ISSUED
2008/04/23

911120
Revision 0

Engineering Services for the Next Generation Nuclear Plant (NGNP) with Hydrogen Production

NGNP Steam Generator Alternatives Study

Prepared by General Atomics
For the Battelle Energy Alliance, LLC

Subcontract No. 00060845
Uniform Filing Code UFC:8201.3.1.2

GA Project 30283

GENERAL ATOMICS

GA 1485 (REV. 08/06E)

ISSUE/RELEASE SUMMARY

☐ R & D ☐ DV&S ☒ DESIGN ☐ T&E ☐ NA	APPVL LEVEL	DISC	QA LEVEL	SYS	DOC. TYPE	PROJECT	DOCUMENT NO.	REV
	5	O	I	N/A	RGE	30283	911120	0

TITLE:

NGNP Steam Generator Alternatives Study

CM APPROVAL/ DATE	REV	PREPARED BY	APPROVAL(S) ENGINEERING	QA	PROJECT	REVISION DESCRIPTION/ W.O. NO.
7 ISSUED APR 23 2008	0	M. Labar R. Phelps J. Saurwein	A. Shenoy	K. Partain	J. Saurwein	Initial Issue A30283-0350

CONTINUE ON GA FORM 1485-1

* See list of effective pages

NEXT INDENTURED DOCUMENT(S)

N/A

COMPUTER PROGRAM PIN(S)

N/A

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LIST OF EFFECTIVE PAGES

Page Number	Page Count	Revision
Cover page	1	0
ii through xxi	20	0
1 through 76	76	0
Back page	1	0
Total Pages	98	

EXECUTIVE SUMMARY

The NGNP Preconceptual Design Report [INL 2007] includes a requirement that the NGNP power conversion system (PCS) be capable of producing steam for potential process heat applications. A suggested configuration for the NGNP heat transport system (HTS) is to use an intermediate heat exchanger (IHX) in a primary coolant loop to transfer reactor heat to a secondary loop containing a steam generator (SG) for the production of steam. Having an IHX in the primary system and the SG in a secondary system has the potential benefits of:

- Providing an additional barrier against the release of radionuclides
- Providing an additional barrier against the ingress of moisture into the primary system. Moisture in the primary coolant of a High Temperature Gas-cooled Reactor (HTGR) is detrimental to maintaining the integrity of the reactor graphite core structures

However, HTGR plants have been satisfactorily demonstrated with steam generators in the primary coolant system. Acceptable means are available to prevent excessive moisture ingress into the primary coolant from steam generators with reactor helium coolant on one side (the primary side) and water/steam on the other side (the secondary side). Accordingly, the study described herein was undertaken to evaluate the relative merits of alternative HTS configurations for the NGNP including configurations with SGs located in the primary system and configurations with SGs located in secondary systems.

Demonstrated HTGR Steam Generators

There have been four HTGR plants operated that have demonstrated Rankine power conversion cycles with SGs in the primary system, Peach Bottom I, Fort St. Vrain, AVR, and THTR. The technology and experience from these plants was used by General Atomics to develop HTGR plant designs with SGs in the primary system for the following plants:

- Large HTGR plant (circa 1972): - Ten larger HTGR plants in the range of 2000 to 3000 MWt each were ordered and in the process of design and license in the early 1970s when the middle-east oil embargo lead to the cancellation of these plant orders (along with about 100 other nuclear plants on order at the time). Preliminary design for a number of the large HTGRs had been completed, Preliminary Safety Analysis Reports (PSARs) had been submitted to the USNRC and licensing had advanced to the stage of construction permit on two of the plants.
- Modular High Temperature Gas-cooled Reactor Steam Cycle (MHTGR) plant [aka Steam Cycle – Modular Helium Reactor (SC-MHR)] (circa 1987) - A conceptual design of the SC-MHR was completed and a Preliminary Safety Information Document (PSID)

was prepared for review with the NRC. Review of the PSID was performed by the NRC over approximately a four year period

- New Production – Modular Helium Reactor (NP-MHR) (circa 1992). – The SC-MHR design concept was adapted to development of a design for the new production reactor plant. The NP-MHR design was advanced to well within the preliminary design stage before the plans for construction of additional production reactors were terminated.

Steam Generator Options for NGNP

As a basis for comparison, one heat transport system configuration with a steam generator in the primary circuit and two heat transport system configurations with a steam generator in a secondary loop were defined. For the current study, helium has been assumed for the secondary fluid for design of the secondary system SGs. The following system design conditions were also assumed:

- SG designs for dual secondary loops, as well as for a single secondary loop (in case high circulator capacity poses too much risk)
- Secondary system SGs of the same type and general arrangement as the SG design described for the SGs located in the primary system (vertically oriented, up-flow boiling, cross-counter flow, once-through shell-and-tube, multiple-tube, helically wound tube bundles).

The two HTS configurations having the SG in a secondary loop were identified as shown in Figures 1 and 2. These are the same HTS configurations selected for evaluation in the companion IHX and secondary heat transport loop study [GA 2008], and the rationale for selection of these configurations are discussed therein.

The HTS configuration shown in Figure 1 (the “serial HTS configuration”) has a single primary loop containing a 612-MWt IHX to supply heat to a secondary heat tranpsort loop. The secondary loop supplies a portion of the hot secondary helium flow to the hydrogen process heat exchanger. The balance of the hot secondary helium flow is mixed with the secondary flow returning from the hydrogen process prior to entering the SG.

The HTS configuration shown in Figure 2 has two parallel primary system loops, one that contains a 65-MWt IHX to transfer heat to the hydrogen production plant via a secondary loop and a second primary loop that contains a 547-MWt IHX to supply heat to the secondary loop that contains the SG.

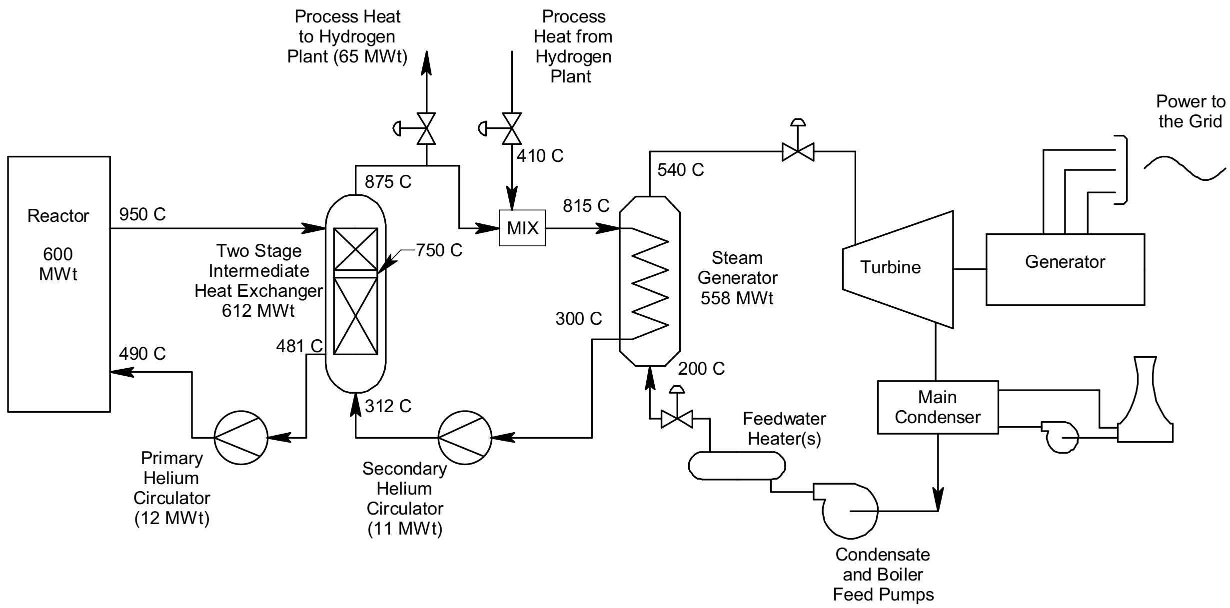

Figure 1. Steam Generator in Secondary Loop – Serial HTS Configuration (Configuration I)

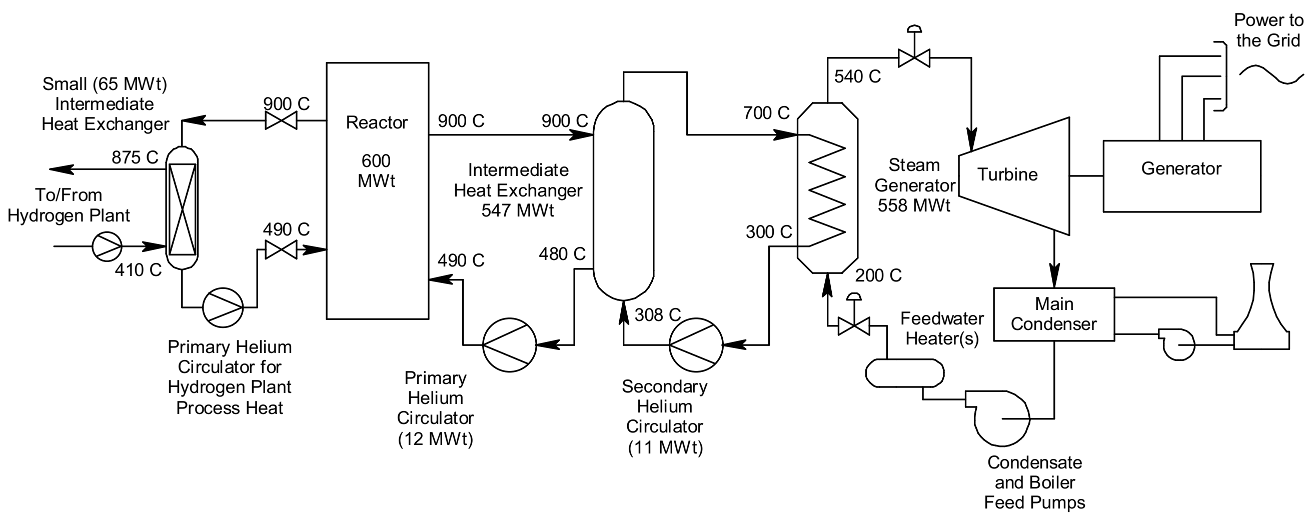

Figure 2. Steam Generator in Secondary Loop – Parallel Primary Loop Configuration (Configuration II)

Both of these configurations with steam generation in a secondary loop has significant investment risk under transient conditions. For example, loss of secondary helium flow without tripping the primary helium flow will result in rapid IHX heaup. In view of the significant cost increases entailed coupled with the significant risk, General Atomics does not recommend these configurations for use in the NGNP program.

Figure 3 shows the HTS configuration selected for this study that includes a steam generator in the primary loop. This configuration includes parallel primary loops. One primary loop contains a small 65-MWt IHX to transfer process heat via a secondary loop to the hydrogen production facilities. The second primary loop contains a SG to generate steam for either process steam users or for the generation of electricity using a Rankine cycle power conversion system. The SG design and the design of the primary circuit containing the SG in this arrangement are the same as developed by the HTGR Program for the SC-MHR plant design [CDSR 1987]. The SC-MHR power conversion system is based on using a non-reheat steam cycle having a steam turbine with a single-flow high pressure (HP) component and double-flow Intermediate-pressure (IP) and Low-Pressure (LP) components. Double isolation valves are used in the steam and feedwater lines at the radionuclide control boundary between the nuclear and non-nuclear portions of the SC-MHR plant.

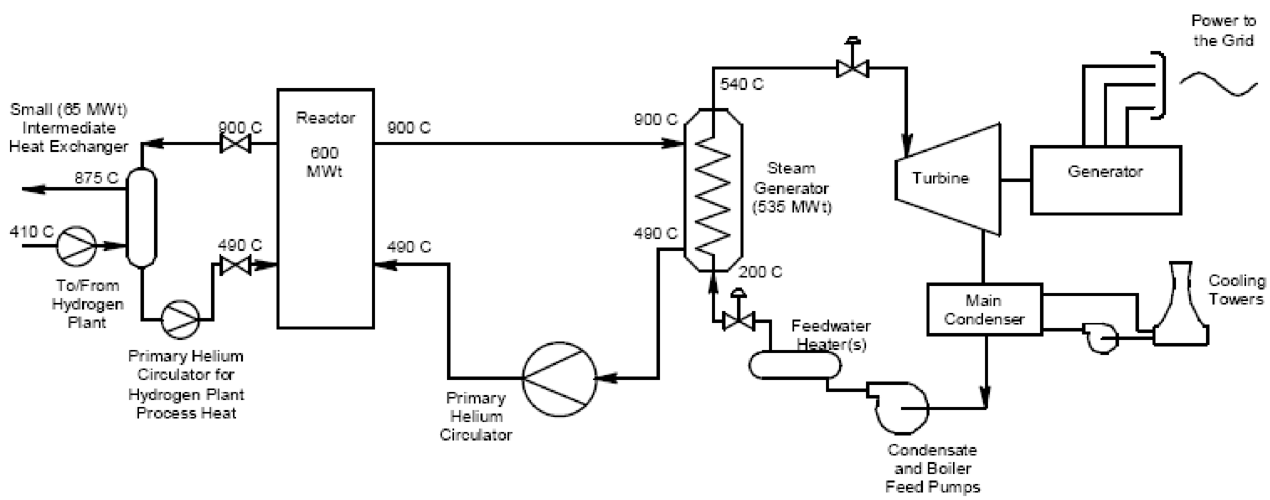

Figure 3. Steam Generator in Primary Loop (Configuration III)

The primary reasons for selecting this configuration for the current study are:

- To provide a configuration for the NGNP that employs a primary coolant system envisioned to be prototypic of a commercially viable steam-electric co-generation plant
- To provide a means of supplying process heat to the hydrogen production process in a parallel loop, de-coupled from steam generation. (Putting the process heat exchanger in series with the steam generator would result in a considerable pressure drop penalty.)

As shown in Figure 3, both of the parallel primary loops require circulators. An SC-MHR requirement intended to be used for the NGNP primary loop He circulators is for the circulators to be mounted on magnetic bearings to avoid bearing lubrication contamination of the primary circuit. The required circulator power for the main SG primary loop is on the order of 10 MW or more if a single circulator in a single SG coolant loop is used as implied by the general arrangement given in Figure 3. This circulator power is greater than that for any currently developed electric motor driven helium circulator mounted on magnetic bearings. While magnetic bearing circulators of up to ~15 MW are considered feasible, there is, nevertheless, some risk that one could be developed on a schedule consistent with the NGNP schedule. The use of two circulators, either in the same primary loop or in two parallel loops, is judged to reduce the required circulator unit power to around 5 MW or so. Development of applicable electric motor driven He circulators mounted on magnetic bearings with this capacity is well advanced. A configuration that has two primary SG loops may therefore be a lower risk option for the NGNP.

In the primary loop(s), the SG is housed in a pressure vessel with its thermal center located below that of the reactor core. The steam generator is a vertically oriented, up-flow boiling, cross-counter flow, once-through shell-and-tube heat exchanger that utilizes multiple tube, helically wound tube bundles. The design employs two bundles, a lower bundle and an upper bundle. The lower bundle contains economizer, evaporator and initial superheater sections and uses 2¼Cr – 1Mo material for the tubing. The upper bundle contains a finishing superheater section and uses Inconel 617 material for the tubing. A bimetallic weld is required to join the two tube materials. The bimetallic weld is located between the two bundles. Previous HTGR steam generator designs used 2¼Cr – 1Mo material for economizer, evaporator and initial superheater tubing and Incoloy 800H for the finishing superheater section. Developing a bimetallic weld between 2¼Cr – 1Mo and Inconel 617 is not expected to be any more difficult than a bimetallic weld between 2¼Cr – 1Mo and Incoloy 800H.

The design provides access for tube leak detection and plugging from both ends of each tube. In addition, the design makes possible the removal and replacement of the steam generator tube bundle through a removable upper vessel head.

The primary benefit of locating the SG in a secondary circuit is the additional barrier provided by the IHX for control of radionuclides. This benefit does, however, entails significant additional costs associated with the following:

- Engineering design development of an IHX with a capacity on the order of 600 MWt (may be more challenging than an IHX with a capacity on the order of 65 MWt). Either size may require provisions for periodic replacement of sections having high operating temperatures but, replacement of all the heat exchanger surfaces for a 65-MWt unit would be less cost prohibitive than for a 600-MWt unit.
- IHX capital cost

- Capital cost of additional systems, structures and components (SSCs) The additional SSCs include the secondary system circulator, secondary system heat transport fluid service systems (purification, storage, and transfer) secondary system piping, secondary system controls, secondary system housing and support structures, etc.
- O&M costs for the additional SSCs.
- Engineering development cost of isolation valves between the primary and secondary to isolate the secondary from the primary. Isolation valves are necessary to realize the potential benefits of incorporating SGs in a secondary system. There are no currently available large-size He isolation valves. There are, however, suitable isolation valves available for steam-water secondary systems.
- Capital cost and O&M cost for the isolation valves.

Other potential benefits of incorporating the SG in a secondary system include:

- The potential for reduced SG cost due to the possibility for (1) using commercial codes and standards for the SG, (2) SG not needing to be configured within tight confines and (3) SG not needing to be subject to nuclear regulatory requirements. But, to realize these advantages, nuclear grade isolation valves would be required between the primary and secondary circuits. These valves would add to the nuclear side cost.
- Incorporating a reheater in a secondary circuit (in series with the SG) should be easier to accomplish than incorporating a reheater in the primary circuit. The incentive for such a reheater would be to reduce moisture in the low-pressure turbine and to increase power conversion efficiency.
- Potential for use of other alternative heat transport fluids in the secondary circuit. Use of CO_2, for example, as the secondary heat transport fluid might enable utilization of steam generation and power conversion experience and technology from the Advanced Gas Reactor (AGR) program in the U.K. There is, however, an inconsistency that would require resolution to make this possible. The maximum AGR CO_2 SG inlet temperature (~640°C) is somewhat lower than the secondary system temperatures indicated in Figure 2.

<u>Economic Comparison</u>

An insight into the impact of the alternative HTS configurations on plant economics was developed from consideration of the HTS capital equipment requirements and the associated equipment costs relative to total plant costs. [GCRA 1993] contains capital equipment costs for modular high temperature gas-cooled reactor steam cycle (SC-MHR) plants. Rough order of magnitude (ROM) capital cost estimates for the alternative HTS configurations and for the entire plant were developed using cost data from [GCRA 1993] with the following simplifying assumptions:

- A scaling factor of 0.65 applies (for estimating HTS capital cost of similar systems with different power capacities)
- The capital costs of heat exchangers having equivalent heat ratings are equivalent regardless of whether the heat exchangers (HEs) are of a shell-and-tube design or a PCHE design. Although PCHEs are more compact than shell-and-tube HEs, they are more expensive to manufacture so, for the ROM cost estimates, the two types were assumed to have equivalent costs for equivalent capacities.

Entire plant cost estimates, complete with buildings, structures and electricity production facilities, were developed to capture the significance of the cost differences for the alternative HTS configurations (the HTS is a small part of the total plant). These cost estimates are summarized in Table 1. The estimated costs include the cost of the SSCs (IHX, circulator, etc) for producing hydrogen process heat because they are an inherent part of the alternatives. However, the plant costs do not include the SSCs for transport of the process heat to the hydrogen production facility nor are the hydrogen production facility costs included because these costs do not impact the relative costs of the alternative HTS configurations on steam-electric co-generation costs.

Table 1. Comparison of ROM Plant Direct Capital Costs for Alternative HTS Configurations

	Main HTS Primary Loop (See Note 1)				Main HTS Secondary Loop (See Note 1)				Process Heat Loop			Plant (See Note 2 & 3)		
	HE Type	Nunber	HE Capacity, MWt	HTS Direct Capital Cost, '07M$	HE Type	Nunber	HE Capacity, MWt	HTS Direct Capital Cost, '07M$	Nunber of IHXs	IHX Capacity, MWt	HTS Direct Capital Cost,'07M$	Total HTS Capital Cost, '07M$	Total Plant Capital Cost, '07M$	Relative Cost Impact (See Note 4)
Reference MHTGR HTS	SG	1	450	71.7	--	--	--	0	0	0	0	71.7	547.6	1.11
NGNP with SG in Primary Coolant Loop (Configuration III)														
Singlle Main Loop	SG	1	600	86.4	--	--	--	0	1	65	20.4	106.8	660.2	1.00
Dual Main Loops	SG	2	300	110.1	--	--	--	0	1	65	20.4	130.5	683.9	1.04
NGNP with SG in Secondary Coolant Loop (Configuration II)														
Singlle Main Loop	IHX	1	600	86.4	SG	1	600	86.4	1	65	20.4	193.2	746.5	1.13
Dual Main Loops	IHX	2	300	110.1	SG	2	300	110.1	1	65	20.4	240.6	794.0	1.20
NGNP with SG in Secondary Coolant Loop (Configuration I)														
Singlle Main Loop	IHX - S1	1	220	45.0	SG	1	600	86.4	0	0	0			
	IHX - S2	1	380	64.2	SG	1	600	86.4	0	0	0	195.6	749.0	1.13
Dual Main Loops	IHX - S1	2	110	57.4	SG	2	300	110.1	0	0	0			
	IHX - S2	2	190	81.8	SG	2	300	110.1	0	0	0	249.3	802.7	1.22

Notes:

1. For the purposes of estimating approximate capital costs, the heat duty of the main heat exchangers was assumed to have a nominal rating of 600 MWt
2. "Plant" as used in this table includes all of the SSCs for electricity generation, process steam production and process heat production but excludes SSCs associated with transport of process heat to the hydrogen production facility and the SSCs for hydrogen production.
3. Capital cost as used here is only the direct capital cost component (indirect costs are not included).
4. Relative to 600 MWt plant with single SG in singe main primary loop.

The ROM cost estimates in Table 1 indicate the following:

- For a NGNP plant with a single main primary loop containing a SG, the plant capital component of production costs would increase by about 11% if the plant capacity was reduced from 600 MWt to 450 MWt. Note, however, the plant capital component of product cost represents only a portion of the product cost. The plant capital component for nuclear plants is typically on the order of 50% of the total product cost.
- The ROM effect of the capital cost component on product cost of using dual SG primary loops with each loop having ½ of the plant capacity is estimated to be about a 4% increase relative to using a single SG primary loop. There would also be an increase in the O&M component of product cost due to the added equipment so the total product cost would be expected to increase on the order of this amount.
- The ROM effect of the capital cost component on product cost of using a single main primary loop containing an IHX coupled to a single secondary loop containing a SG is about a 13% increase relative to using a single SG primary loop. Again, the total product cost would be expected to increase on the order of this same amount.
- The ROM effect of the capital cost component on product cost of using dual main primary loops each containing an IHX coupled to a secondary loop containing a SG is about a 20% increase relative to using a single SG primary loop. Again, the total product cost would be expected to increase on the order of this same amount.
- The ROM effect of the capital cost component on product cost of using a single main primary loop containing staged IHXs coupled to a single secondary loop containing a SG and a take off for (and a return line for) hydrogen process heat is about a 13% increase relative to using a single SG primary loop. Again, the total product cost would be expected to increase on the order of this same amount.
- The ROM effect of the capital cost component on product cost of using dual main primary loops each containing staged IHXs coupled to a secondary loop containing a SG is about a 22% increase relative to using a single SG primary loop. Again, the total product cost would be expected to increase on the order of this same amount.

Relevant conclusions from these results, the relative RB cost information in [GA 2008] for the alternative HTS configurations and the comparative economics of alternative plants in [GCRA 1993] are as follows:

- The most economic NGNP HTS configuration is a single primary main loop containing a single SG and circulator.
- If the required circulator capacity is excessive for a single SG primary loop plant, dual circulators in the single loop could be used, or dual SG primary loops could be used. A

dual primary loop HTS configuration with each loop containing a SG should be competitive with alternative types of steam-electric co-generation plants.

- The commercial plant economics are not expected to be competitive for a plant based on the NGNP having a single SG secondary loop coupled to single IHX primary loop due to the significantly increased capital + O&M cost and decreased availability (relative to the single SG primary loop concept).
- The commercial plant economics for a plant having dual IHX primary loops each coupled to a secondary SG loop are even less attractive than single IHX loop concept (greater capital + O&M and lower availability).
- Economics of commercial plants having staged IHXs primary loops, coupled to secondary SG loops with take-off H_2 process heat are expected to be about the same as the non-staged IHX HTS options.

These ROM economic results and conclusions only indicate trends. More complete design definitions are needed to develop more comprehensive cost estimates to enable more definitive economic analyses.

Plant Control and Protection Comparison

Plant Control and Protection Systems (PCPS) can be developed for each of the three alternative HTS configurations. These can rely on earlier MHR and HTGR control/protection concepts with varying degrees of difficulty. Key concerns are secondary loops incorporated in the reactor heat removal processes, development of dual-production control features, and selecting the most beneficial operational and safety features from the many possible options. At the current level of design detail, no clear selection of one HTS configuration can be derived from projection of the necessary control and protection design efforts because the same overall design scope is expected for any of the HTS configurations. However, it is expected that designs with the SG in a secondary loop will have significantly more complex control and protection systems.

Safety Comparison

The primary safety benefit of locating the SG in a secondary loop is the additional barrier provided by the IHX for control of radionuclides. Locating the SG in a secondary loop reduces the probability of introducing water into the primary system, which can cause oxidation of the core graphite and hydrolysis of the fuel kernels in fuel particles having failed coating layers, thereby increasing the release of radionuclides from the fuel.

The safety analyses contained in [PSID 1992], which was generated for the reference SC-MHR plant [CDSR 1987] were reviewed to gain insights into the relative safety hazards of locating the SG in the primary circuit. The conclusions from this review are as follows:

- Moisture ingress into the primary coolant system from steam generator leakage is not expected to result in unacceptable average or localized oxidation of either the bulk core moderator graphite or the graphite core support components.
- Moisture ingress into the primary coolant system from steam generator leakage is not expected to result in radionuclide releases in excess of regulatory limits.

Placement of the steam generator in a secondary loop connected to the nuclear heat source through an IHX should eliminate issues associated with moisture ingress into the core from the steam generator. However, there are also safety-related issues associated with including an IHX in the primary circuit. These issues include:

- There is the probability of a major pressure difference developing between the primary and secondary sections of an IHX. Either the IHX must be designed to as a Class I primary pressure boundary component, or the secondary system must contain Class I isolation valves near to the IHX, or the secondary system must be designed as the primary pressure boundary.
- There is uncertainty that an IHX can be designed as a Class 1 component having a reasonable lifetime taking into account the creep fatigue damage caused by occasional high pressure differentials at temperature.
- There is uncertainty that suitable isolation valves can be developed. No suitable design of large size, high temperature He leak-tight valves are currently available.
- Designing the secondary system to satisfy the requirements of a Class I primary pressure boundary is expected to cause excessive plant costs.

Maintainability Comparison

The dominate maintainability issue addressed for evaluation of the three alternative HTS configurations relates to the requirements for maintaining SGs and IHXs. The basic conclusions reached on this issue are as follows:

- Provisions are needed in the design of SGs and the plant building/structures for finding and repairing water leaks in the heat transfer surfaces. Designs of helically coiled tube-and-shell SGs have been developed in which individual tubes can be inspected and plugged to repair leaks.

- Provisions are required for resolving leaks in IHXs. A desirable solution would be one analogous to steam generator tube plugging where excess heat transfer area is provided in the design to allow for some leaking surfaces to be isolated. For tube-and-shell IHXs, the approach could be the same as for steam generators. The situation is, however, quite uncertain for compact IHX designs.
- Currently, the only known solution for compact IHXs is heat transfer surface replacement, either as complete heat exchanger replacement or replacement of heat exchanger modules.
- Replacement of either complete IHXs or failed modules is envisioned to be considerably more involved than plugging tubes. As a result, compact IHXs present a much more complicated and uncertain maintenance situation for resolution of leakages.
- Uncertainties concerning IHX maintainability, coupled with the creep-fatigue design uncertainties, indicate high uncertainties for NGNP IHX designs based on compact heat exchanger concepts. High uncertainty translates to high risk and, for the NGNP, the risk seems large for demonstration of the VHTR commercial steam-electric co-generation application.
- The risk might be acceptable for the hydrogen production process heat demonstration application that uses an IHX about 1/10 the heat capacity of the steam-electric co-generation commercial demonstration application.
- The uncertainties associated with the use of tube-and-shell IHX designs are perceived to be less than those of compact IHXs. Tube-and-shell IHXs are, however, considerably larger and, even though they are amendable to tube plugging, are more prone to requiring replacement than steam generators due to higher tube operating temperatures.
- The large size of tube-and-shell IHXs, including impact on building size, translates into high capital cost and replacement, if required, translates into high maintenance costs. These two effects further enforce in the above economic conclusion section that an IHX in a primary coolant system coupled with steam generation in a secondary system would not be economic for commercial application.

Tritium Transport

A design issue of special interest for the NGNP is tritium control. Tritium will be produced in an HTGR by various nuclear reactions. Given its high mobility, especially at high temperatures, some tritium will permeate through the intermediate heat exchanger, steam generator, and hydrogen process vessels, contaminating the product hydrogen and process steam. This tritium contamination will contribute to public and occupational radiation exposures; consequently, stringent limits on tritium contamination in the product hydrogen are anticipated to be imposed by regulatory authorities.

Design options are available to control tritium in an HTGR, but they can be expensive so an optimal combination of mitigating features must be implemented in the design. It would be easier to control tritium transport to NGNP end products if the steam generator is located in a secondary loop (rather than a primary loop) because this HTS configuration would allow for inclusion of a second helium purification system in the secondary loop to remove tritium; however, tritium control will be manageable regardless of whether the steam generator is located within a primary or secondary loop. Consequently, tritium transport control is not considered to be a major factor in determining the location of the steam generator in the NGNP HTS.

Commercial Prototype Comaprison

The conclusions reached on the three alternative HTS configurations with regard to being prototypic of a commercial steam-electric co-generation plant based on the depth of the current study are as follows:

- None of the HTS configurations with an IHX in the primary coolant system coupled to a SG in a secondary system are expected to be economically competitive for a commercial steam-electric co-generation plant and would, therefore, not serve well as an applicable prototype for commercial plant demonstration.
- A VHTR steam-electric co-generation plant having a SG in the primary system should be commercially competitive and would satisfy safety requirements.

Top Level Recommendation

Based on the conclusions of the economic, control and protection, safety, maintainability, tritium transport, and commercial prototype evaluations performed in this study and summarized above, it is recommended that an NGNP plant design that includes the required SG in a primary loop be selected for further design development and better definition of estimated costs and safety performance.

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ACRONYMS AND ABBREVIATIONS

AC	Alternating Current
AGR	Advanced Gas Reactor
ASME	American Society of Mechanical Engineers
AVR	Arbeitsgemeinschaft Versuchsreaktor
BOP	Balance of Plant
CCCT	Combined Cycle Combustion Turbine
CDS	Control Develment Simulator
CFR	Code of Federal Regulations
DBE	Design Basis Event
DC	Direct Current
DOE	Department of Energy
EAB	Exclusion Area Boundary
EPC	Engineering, Procurement and Construction
EPZ	Emergency Planning Zone
FSV	Fort St. Vrain
FW	Feed Water
GA	General Atomics
GNEP	Global Nuclear Energy Partnership
GT-MHR	Gas Turbine Modular Helium Reactor
HE	Heat Exchanger
HMI	Human-Machine Interface
HP	High-Pressure
HPS	Helium Purification System
HTGR	High Temperature Gas Reactor
HTS	Heat Transport System
I&C	Instrumentation and Control
IGCC	Integrated Gasification Combined Cycle
IHX	Intermediate Heat Exchanger
INL	Idaho National Laboratory
IP	Intermediate-Pressure
IPS	Investment Protection System
KAERI	Korean Atomic Energy Research Institute

LP	Low-Pressure
LWR	Light Water Reactor
MHR	Modular Helium Reactor
MW	Mega Watt
N/A	Not Applicable
NGNP	Next Generation Nuclear Plant
NP-MHR	New Production – Modular Helium Reactor
NPR	New Production Reactor
NRC	Nuclear Regulatory Commission
O&M	Operation and Maintenance
PB1	Peach Bottom 1
PCDIS	Protection and Control Data Instrumentation System
PCHE	Printed Circuit Heat Exchanger
PCPS	Plant Control and Protection Systems
PCRV	Pre-Stressed Concrete Reactor Vessel
PCS	Power Conversion System
PSAR	Preliminary Safety Analysis Report
PSID	Preliminary Safety Information Document
RB	Reactor Building
RCCS	Reactor Cavity Cooling System
ROM	Rough Order of Magnitude
RPS	Reactor Protection System
SC-MHR	Steam Cycle – Modular Helium Reactor
SCS	Shutdown Cooling System
SG	Steam Generator
SSC	Systems, Structures and Components
SWEC	Stone and Webster Engineering Corporation
THTR	Thorium High Temperature Reactor
UCO	A mixture of uranium oxide and uranium carbide phases
U.K.	United Kingdom
VHTR	Very High Temperature Reactor

1. INTRODUCTION

1.1 Purpose and Scope

This report describes steam generator options for the NGNP and compares the pros and cons of locating the steam generator in the primary circuit versus a secondary loop.

1.2 Background

The NGNP Preconceptual Design Report [INL 2007] includes a requirement that the NGNP power conversion system (PCS) be capable of producing steam for potential process heat applications. The GA Team concurs with the requirement for the NGNP to produce steam. There are a variety of heat transfer system (HTS) configurations for the production of steam using nuclear heat from the NGNP. One approach is to use an intermediate heat exchanger (IHX) in a NGNP primary coolant loop for transferring reactor heat to a secondary system containing a steam generator (SG). But, locating the steam generator in a secondary loop could conflict with another important requirement that the NGNP be prototypic of a commercial process steam or process steam and electricity cogeneration MHR. Locating SGs in primary coolant loops has been satisfactorily demonstrated in previously operated High Temperature Gas-cooled Reactor (HTGR) plants; namely, the Arbeitsgemeinschaft Versuchs-Reaktor (AVR), Peach Bottom I (PBI), Fort St Vrain (FSV), and the Thorium High Temperature Reactor (THTR).

In this report, an NGNP HTS configuration containing the SG in the primary loop is compared with alternative HTS configurations with SGs in secondary loops. The NGNP steam production objective for all of the alternatives was assumed to be production of representative commercial quality 540°C steam at 2500 psia.

An NGNP alternative that should be considered but was not included in the current study is a combined cycle arrangement that employees a Brayton gas turbine cycle coupled to a bottoming Rankine steam cycle.

2. REVIEW OF MHR STEAM PLANT DESIGNS

There have been four different HTGR plants that have operated and demonstrated steam generator systems with SGs in the primary system, Peach Bottom I, Fort St. Vrain, AVR and THTR. The technology and experience from these plants has been used by General Atomics to develop HTGR plant designs with SGs in the primary system for the following plants:

- Large HTGR plant (circa 1972): - Ten larger HTGR plants in the range of 2000 to 3000 MWt each were ordered and in the process of design and license in the early 1970s when the middle-east oil embargo lead to the cancellation of these plant orders (along with about 100 other nuclear plants on order at the time). Preliminary design for a number of the large HTGRs had been completed, Preliminary Safety Analysis Reports (PSARs) had been submitted to the USNRC and licensing had advanced to the stage of construction permit on two of the plants.
- Modular High Temperature Gas-cooled Reactor Steam Cycle (SC-MHR) plant [aka Steam Cycle – Modular Helium Reactor (SC-MHR)] (circa 1987) - A conceptual design of the SC-MHR was completed and a Preliminary Safety Information Document (PSID) was prepared for review with the NRC. Review of the PSID was performed by the NRC over approximately a four year period
- New Production – Modular Helium Reactor (NP-MHR) (circa 1992). – The SC-MHR design concept was adapted to development of a design for the new production reactor plant. The design NP-MHR was advanced to well within the preliminary design stage before the plans for construction of any additional production reactors were terminated.

The operating experience was reviewed of two of the HTGR plants that demonstrated operation of steam generators in the primary coolant system Fort St. Vrain and AVR. Additionally, the SC-MHR SG design was reviewed. The results of these reviews are contained in the following sections.

2.1 Fort St. Vrain Power Conversion System

2.1.1 System Description

The Fort St. Vrain power conversion system utilized a series of twelve individual steam generator modules divided into two separate primary coolant loops, each containing six modules arranged in parallel. Individual modules were sized to generate about 70 MWt of steam at conventional power plant conditions of 16.54 MPa (2400 psia) turbine throttle pressure and 538°C (1000°F). The steam generator design also included an integral reheater unit that provided for low-pressure steam reheat to 538°C. These units were designed for a “once-through" flow process. Table 2-1 indicates the principal design conditions specified for the Fort St. Vain steam generators.

Table 2-1. Design Conditions for Fort St. Vrain Steam Generator Module

Helium Flow Rate (kg/sec)	35.8	Main Steam Flow Rate (kg/sec)	24.2
Primary Coolant Delta-P (kPa)	96.5	Main Steam Pressure (Mpa)	17.3
Primary Coolant Pressure (MPa)	4.8	Feedwater Temperature (°C)	206
Thermal Capacity (MWt)	70	Main Steam Temperature (°C)	538
Helium Inlet Temperature (°C)	776	Reheat Steam Pressure (MPa)	4.5
Helium Outlet Temperature (°C)	405	Reheat Steam Temperature (°C)	538

Figure 2-1 shows a single steam generator module during fabrication, including the arrangement of the various feedwater and steam lines to and from the heat transfer bundles.

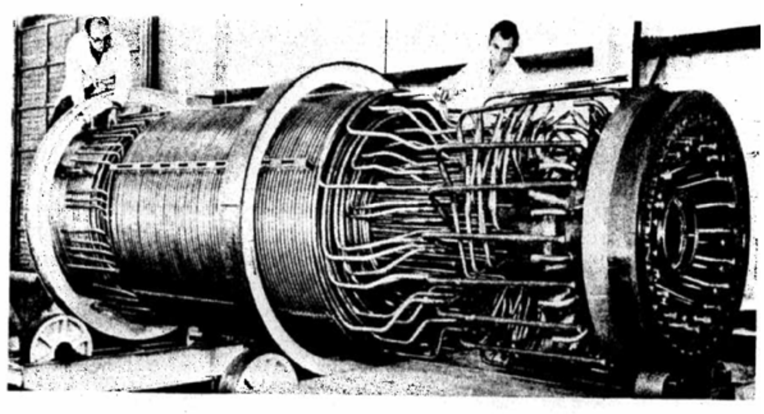


Figure 2-1. FSV Steam Generator Module During Fabrication

Figure 2-2 llustrates a single steam generator module, including the arrangement of the various feedwater and steam lines as they pass through the PCRV bottom head.

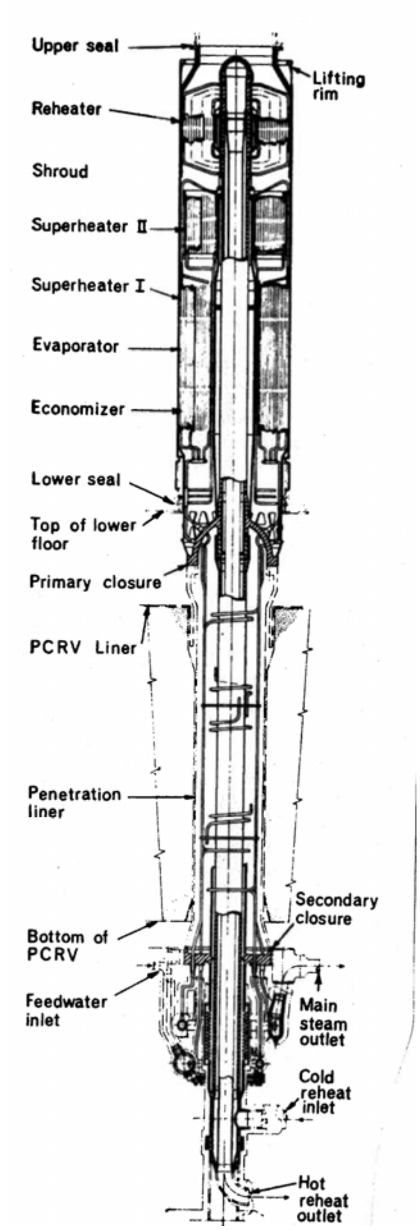


Figure 2-2. FSV Steam Generator Module as Installed in the PCRV Bottom Head

The steam generator modules were all contained within the pre-stressed concrete reactor vessel (PCRV) cavity as part of the primary coolant system. The modules were arranged in a circular fashion with each module at the same radial distance from the vessel centerline. At full reactor power, the hot helium was discharged from the reactor core at 785°C and collected in a plenum below the reactor, from which the flow was directed into each of the twelve modules. Flow to each module was relatively uniform. Inlet temperature to each module could be controlled to some extent by adjusting the primary coolant inlet flow orifices at the entrances to each of the 37 fuel regions of the reactor core.

Upon entering the steam generator, the hot helium first encountered the reheater section of the module, followed by the main steam section. The main steam portion of the module was configured with four sections, commencing with the evaporator at the lower end of the module, followed in series by the economizer section, the evaporator section, the superheater I section and the superheater II section. The super heater II and reheat sections of the steam generator were fabricated from Alloy 800H while the lower-temperature sections of the main steam portions of the unit were fabricated from 2¼ Cr – 1 Mo steel. Helium discharged from the base of the steam generator modules at approximately 406°C and was collected in two separate outlet plenums, one plenum for each primary coolant loop. The two circulators in each loop drew upon these plenums, discharging into a common outlet volume, from which the helium was directed back to the reactor core inlet.

The heat transfer surfaces were arranged in helically-wound coil configurations with support by vertically oriented tube sheets attached to a central column. The bundles of coils were contained by a cylindrical shroud that separated the internal helium flow from the external surrounding helium volume. Incoming feedwater to the main steam inlet sections of each module was distributed into 18 groups of subheader tubes, with each group containing three individual tubes. Elimination of a leak in any one of these tubes by plugging resulted in the loss of three of the 54 individual tubes in the main steam portion of the steam generator.

Feedwater to the economizer/evaporator/superheater I section was designed for counter-current flow relative to the helium primary coolant, while flow in the finishing superheater section was arranged for co-current operation relative to the helium coolant. This arrangement resulted in an "uphill" boiling configuration. Reheat steam flow to the reheater section entered at a temperature of 356°C and exited at 538°C at a pressure of 4.1 MPa (600 psia). The reheater sections of the modules were designed for counter-current steam flow relative to the helium flow.

Because the Fort St. Vrain steam generator modules were contained within the primary coolant system, any substantial steam leak could seriously affect the integrity of the hot graphite reactor core. To prevent damage in the event of an offset tube rupture, provisions were made in the system design to perform a rapid steam-water dump that would effectively empty the steam generator modules into a nearby dump tank in a very short period of time. This system was located below the reactor vessel to minimize the line lengths and response time for this safety system.

The Fort St. Vrain steam generator modules were designed to allow individual on-site handling and initial installation using installed plant equipment provided specifically for the purpose.

Provisions were also made to allow for removal and replacement of a steam generator module should this ever be required.

2.1.2 Steam Generator Performance

The overall thermal performance of the Fort St. Vrain steam generator modules was as expected. The required feedwater, steam, reheat steam, and helium flows were achieved as were the associated design process temperatures. However, secondary losses resulted in overall plant performance somewhat less than expected at power levels below 60%. These losses involved regenerative heat transfer between the various inlet and outlet piping bundles within the PCRV penetration, as well as between the feedwater and steam headers located in the lower regions of the module.

Two tube leaks were experienced over the 17-year operating life of the Fort St. Vrain steam generator modules (1972 through 1989). Each of these leaks occurred in the main steam portions of different modules. In each case, the leak locations were determined and the leaking tube subheaders were plugged. The overall steam generator module design included a 5% margin to accommodate performance loss due to tube plugging.

In each case, these tube leaks were indicated by slow increases in the primary coolant moisture over a period of several hours. As a result, there was no damage to the reactor core due to excessive moisture in the primary coolant while the reactor was operating at its design conditions.

2.2 SC-MHR Steam Generator System

The steam generator system intended for the 350 MW(t) SC-MHR was designed as a single (once-through) steam generator unit (rather than a series of individual modules operating in parallel). Figure 2-3 shows a cross section of the 350 MW(t) SC-MHR steam generator.

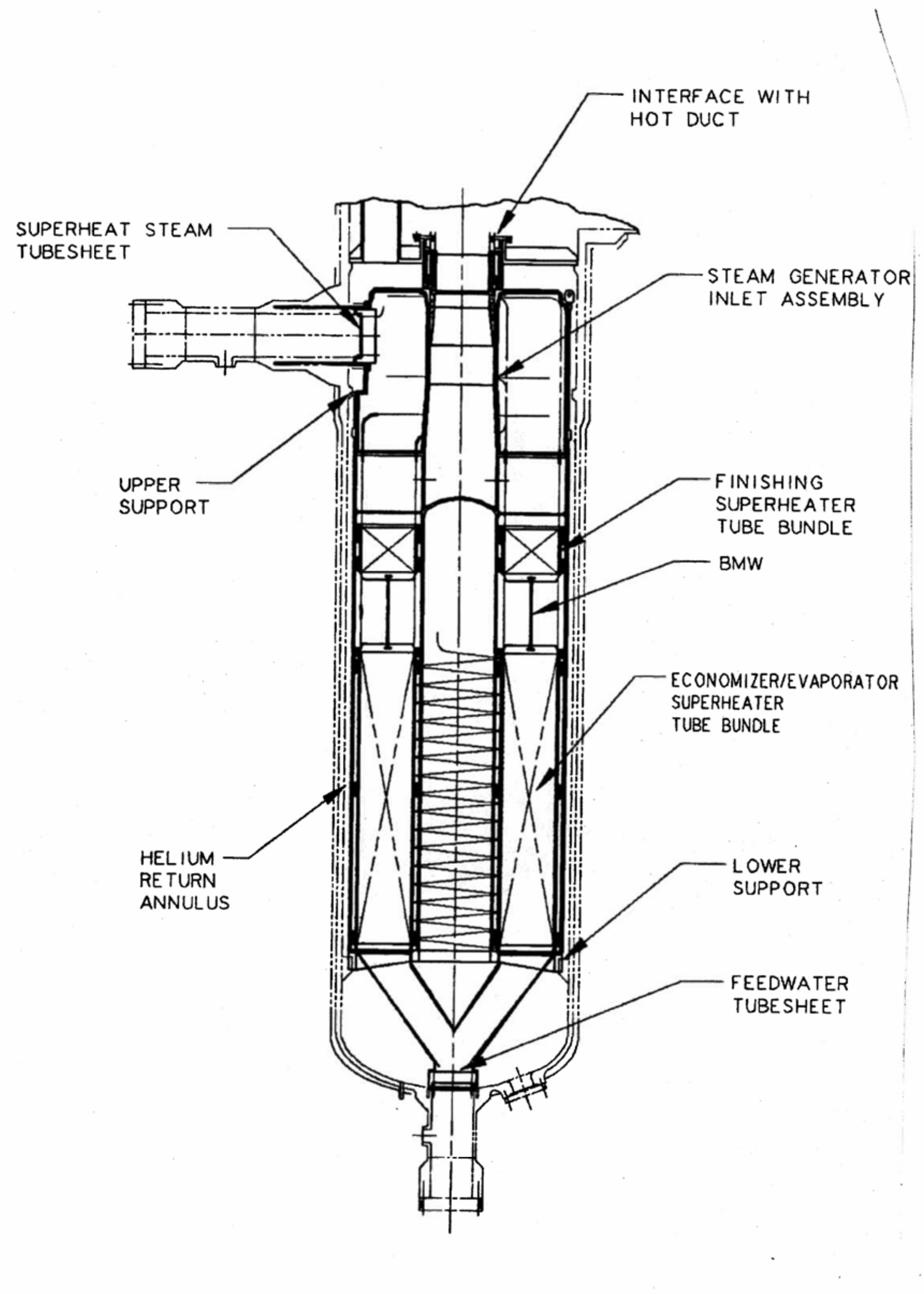


Figure 2-3. 350 MW(t) SC-MHR Steam Generator

In this design, steam is generated by passing the hot primary coolant helium over a system of helically-coiled steam tubes contained in a vertically-oriented enclosure vessel. The helium coolant is circulated through the system by an electric motor-driven, single-stage circulator. Hot helium leaving the reactor vessel flows into the central region of a coaxial cross duct between the reactor vessel and the steam generator vessel. This central region is identified as the hot duct, and connects directly to the inlet of the steam generator. Helium discharged from the steam generator flows upward through an annular space between the tube bundle shroud and the steam generator vessel wall back to the inlet of the primary coolant circulator located at the top of the vessel. Helium discharged from the circulator is ducted back to the reactor inlet through the annular outer region of the cross duct.

Because the steam generator is a once-through design, the feedwater quality is of utmost importance. To this end, 100% of the feedwater flow is passed through a series of full-flow demineralizers prior to being admitted to the steam generators.

2.2.1 Description of Design

Table 2-2 lists the principal design conditions for the 350 MWt steam generator.

Table 2-2. Design Conditions for 350 MWt SC-MHR Steam Generator

Helium Flow Rate (kg/sec)	157.2
Primary Coolant Delta-P (kPa)	34.5
Primary Coolant Pressure (MPa)	6.4
Thermal Capacity (MWt)	350
Helium Inlet Temperature (^{o}C)	687
Helium Outlet Temperature (^{o}C)	259

Main Steam Flow Rate (kg/sec)	121
Main Steam Pressure (Mpa)	17.3
Feedwater Temperature (^{o}C)	193
Main Steam Temperature (^{o}C)	541
Reheat Steam Pressure (MPa)	None
Reheat Steam Temperature (^{o}C)	None

The steam generator assemblyt is approximately 4.1 meters (13.45 ft.) in diameter and 10.3 meters (33.78 feet) in length.

The heat transfer surfaces of the steam generator include an evaporator-economizer section in the lower portion of the enclosure vessel, and a finishing superheater section in the upper portion. There is no provision for a reheater section. In the short space between the evaporator-economizer section and the finishing superheater section, the steam tubes are oriented vertically. The bimetallic weld between the two heat transfer sections is located in these vertical tubes. Materials of fabrication are specified as Alloy 800H for the superheater section and 2¼ Cr – 1 Mo steel in the evaporator-economizer section. In both sections, the steam is designed to flow counter-currently with respect to the primary coolant helium thus resulting in “uphill” boiling. The overall steam generator design included no provision for reheat steam.

As with the Fort St. Vrain steam generators, provision is made in the system design to allow for a rapid steam-water dump of the steam generator contents to minimize water ingress to the primary coolant in the event of a large tube leak. Simultaneously, the feedwater and steam lines are also immediately isolated during this event.

2.2.2 Design Issues

The bimetallic weld between the two sections of the steam generator must be performed under carefully controlled conditions using methods and techniques that ensure these welds satisfy high quality requirements. Although the materials selected for the heat transfer tubes is known to perform satisfactorily under the expected operating conditions, further research into high-temperature materials was planned to assure the integrity of the finished product. Proper heat transfer and structural strength properties must be achieved during fabrication of the steam generator to assure both reliability and duration of operation in high-temperature service. Since the steam generator (if installed in the primary system) represents a primary pressure boundary, its fabrication must comply with requirements of a Class I system. The quality control and quality assurance programs were expected to be of the utmost importance during fabrication of these units.

There is potential for degradation of the steam generator materials due to impurities contained in the primary coolant helium. These include primarily CO, CO_2, CH_4, and moisture (H_2O). These impurities, within the expected ranges of concentration in the primary coolant, can create environments that are conducive to decarburization of both high- and low-chromium alloys, as well as environments in which high-alloy materials may carburize while low-chromium ferritic steels will carburize. This indicates that a helium purification system designed to continuously remove such impurities from the primary coolant is of considerable significance to the long-term integrity of the steam generators.

Careful attention must be paid to the possibilities of regenerative heating between the various internal flow paths within the steam generator structure. Detailed analyses must be performed to assure that no unacceptable mechanical or thermal stresses develop in the structure during all modes of operation, including transients. Effects of seismic disturbances must also be recognized and appropriate structural elements included for accommodating the loads so induced.

2.3 AVR Power Conversion System

The AVR (Arbeitsgemeinschaft Versuchs-Reaktor) was designed as a small pebble bed experimental research reactor capable of generating 46 MWt. The reactor research facility was located at Julich, Germany and was operated from 1968 through 1988. It was equipped with one steam generator coupled to a 15 MWe turbine generator. Table 2-3 lists the principal design conditions for the steam generator. Although the maximum design temperature for the primary coolant helium was 950°C to accommodate various experimental purposes, such as process heat capability, the reactor was not normally operated at this level of outlet temperature.

Table 2-3. Design Conditions for the AVR Steam Generator

Helium Flow Rate (kg/sec)	35.8	Main Steam Flow Rate (kg/sec)	24.2
Primary Coolant Delta-P (kPa)	57.9	Main Steam Pressure (Mpa)	17.3
Primary Coolant Pressure (MPa)	4.8	Feedwater Temperature (^{o}C)	206
Thermal Capacity (MWt)	70	Main Steam Temperature (^{o}C)	538
Helium Inlet Temperature (^{o}C)	776	Reheat Steam Pressure (MPa)	4.5
Helium Outlet Temperature (^{o}C)	405	Reheat Steam Temperature (^{o}C)	538

2.3.1 Design Description

The AVR steam generator was contained inside the reactor vessel, suspended from the vessel closure head. All tubes to and from the steam generator passed through this head. Materials of fabrication for the steam generator were ferritic steels commonly used in boiler systems. The steam generating portions of this unit were divided into four identical but independent sections. In each section, the steam tubes themselves were bent into the form of an involute, which is a curved shape that allows two adjacent tubes of the same length to be arranged parallel to each other over the entire heat transfer cross section thus allowing the water or steam to pass uniformly through the entire circular heat transfer cross section formed by the tube bundle. Figure 2-4 shows the general shape and complexity of the steam generator tubes.

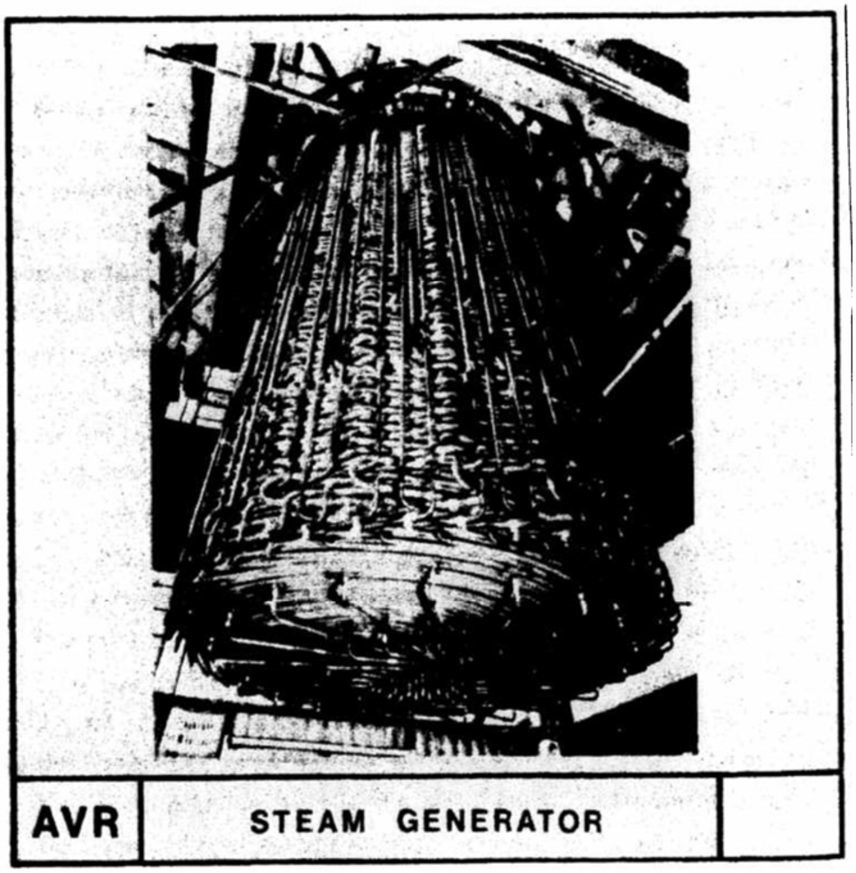


Figure 2-4. AVR Steam Generator Tube Bundle

2.3.2 Steam Generator Performance

The AVR steam generator operated for more than ten years before the first and only tube leak was detected. Since the steam generator had been designed with sufficient excess heat transfer surface to accommodate a loss of almost 10% of its capacity, there was no significant degradation in performance. At the end of 1988, after more than 21 years of plant operation, the AVR steam generator had accumulated more than 150,000 hours of operation at temperatures up to 950°C.

3. STEAM GENERATOR OPTIONS FOR NGNP

Three Heat Transport System (HTS) configuration options have been identified as candidates for a steam-electric co-generation NGNP, one with a steam generator in the primary circuit and two with a steam generator in a secondary loop. These configurations are described and discussed in Sections 3.1 and 3.2.

3.1 Steam Generator in Primary Circuit

A flow and heat balance schematic for the HTS configuration with the steam generator (SG) in the primary circuit (HTS Configuration III) is given in Figure 3-1. The HTS configuration contains two parallel primary loops, one primary loop that contains a small 65-MWt IHX to generate process heat for the hydrogen production facilities and a second primary loop that contains a SG to generate steam for either process steam users or for the generation of electricity using a Rankine cycle power conversion system.

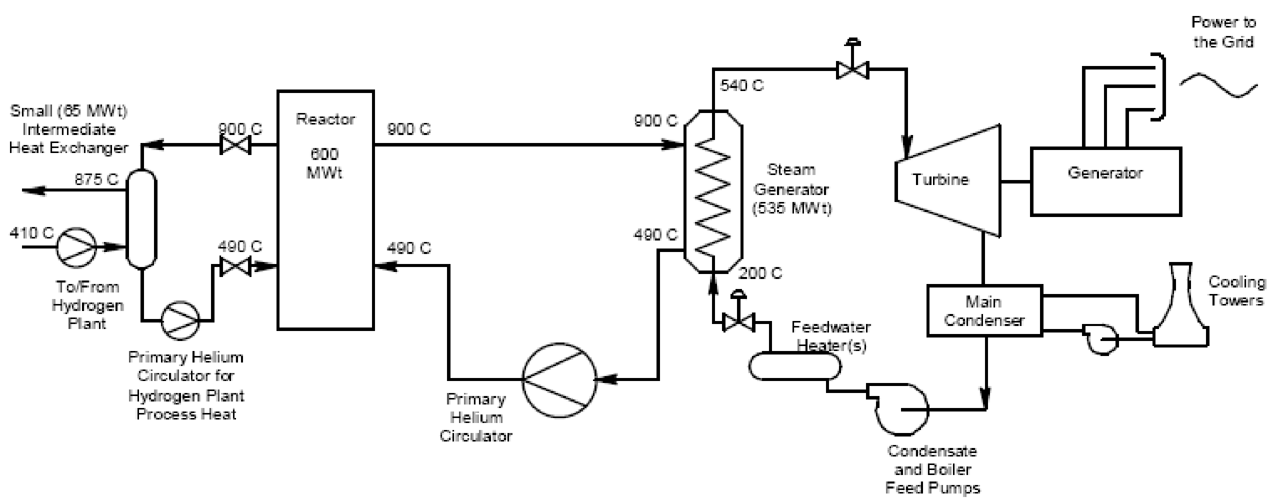


Figure 3-1. Steam Generator in Primary Loop (HTS Configuration III)

The arrangement selected in this study for the both the SG and SG loop is the arrangement developed by the HTGR Program for the SC-MHR plant design [CDSR, 1987]. A simplified flow diagram from [CDSR, 1987] for the SC-MHR plant is shown in Figure 3-2. The SC-MHR power conversion system is based on using a non-reheat steam cycle having a steam turbine with a single-flow high pressure (HP) component and double-flow Intermediate-pressure (IP) and Low-Pressure (LP) components. Double isolation valves are used in the steam and feedwater lines at the radionuclide control boundary between the nuclear and non-nuclear portions of the SC-MHR plant. The primary reasons for selecting this configuration for study are:

- To provide a configuration for the NGNP that employs a primary coolant system envisioned to be prototypic of a commercially viable steam-electric, co-generation plant
- To provide a means of supplying process heat to the hydrogen production plant via a parallel loop, de-coupled from steam generation. Putting the process heat exchanger in series with the steam generator would result in a considerable pressure drop penalty.

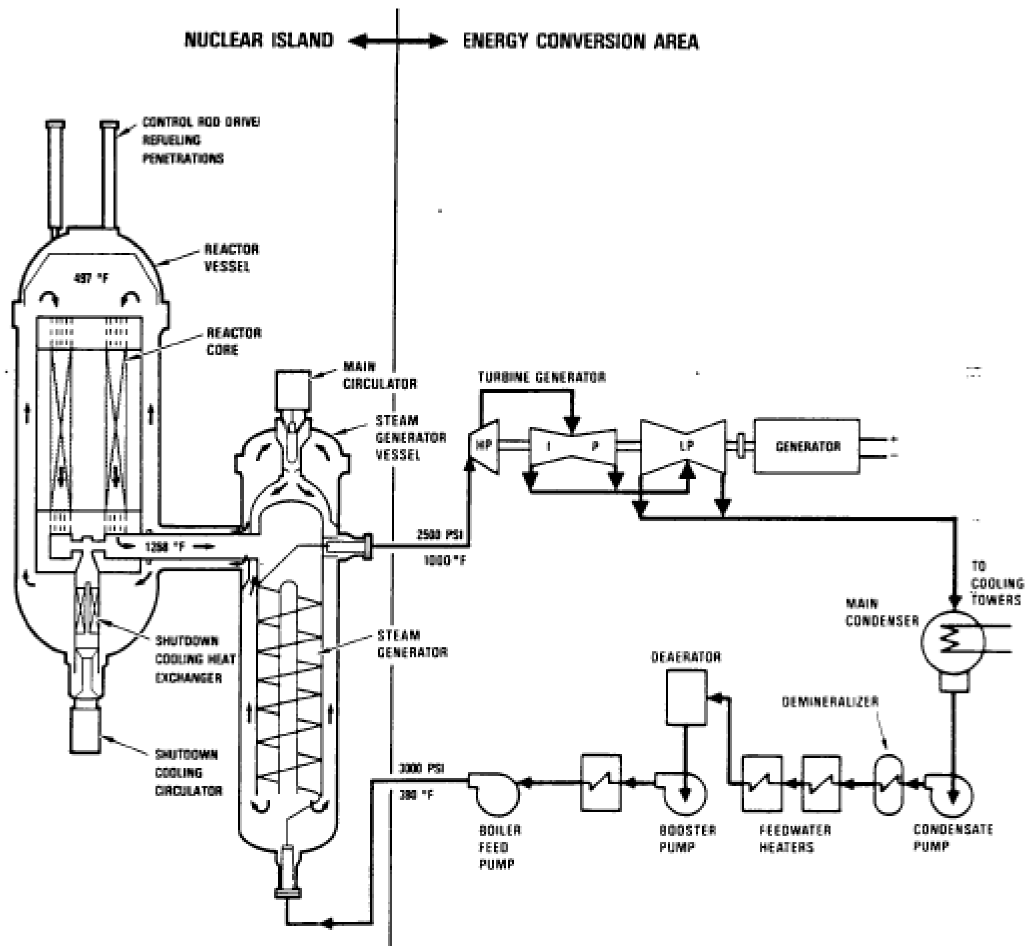


Figure 3-2. Simplified SC-MHR Flow Diagram

A fundamental difference between the NGNP and the SC-MHR plant designs is the primary He coolant SG inlet temperature (core outlet temperature) for the NGNP is 900°C while for the SC-MHR it is 687°C. An option considered for the NGNP to reduce the He inlet temperature to the SG is to return some of the colder SG outlet He flow back to the inlet. However, this option was rejected because it would require a substantial increase (about 2X) in the primary circuit helium mass flow rate and in the primary helium circulator power, thereby having a large negative impact on plant efficiency, and would also complicate the primary system piping. The higher primary coolant SG inlet temperature can potentially be accommodated in design by choice of materials of construction and SG operating conditions.

As shown in Figure 3-1, both of the primary loops require circulators. An SC-MHR requirement intended to be used for the NGNP primary loop He circulators is for the circulators to be mounted on magnetic bearings to avoid bearing lubrication contamination of the primary circuit. The required NGNP circulator power for the main SG primary loop capacity is on the order of 10 MW or more if a single circulator in a single SG coolant loop is used as implied by the general arrangement given in Figure 3-2. This circulator power is greater than that for any currently developed He electric motor driven circulator mounted on magnetic bearings. While magnetic bearing circulators of up to ~15 MW are considered feasible, there is, nevertheless, some risk that one could be developed on a schedule consistent with the NGNP schedule. Alternatives considered include using more than one circulator, in parallel or series, in a single primary SG loop, or using parallel primary SG loops. The use of two circulators, either in the same primary loop or by having two parallel loops, is judged to reduce the required circulator unit power to around 5 MW each. Development of applicable electric motor driven He circulators mounted on magnetic bearings with this capacity is well advanced. Two smaller SGs are expected to be somewhat easier to manufacture than one large SG. A two-primary SG loop option is, therefore, concluded to be a lower risk option for the NGNP.

For the case of a SG in a primary loop, isolation valves are expected to be required in the steam line going from the SG to the secondary system and in the feed water line coming from the secondary system to the SG at the radionuclide confinement boundary between the primary and secondary systems. The design of isolation valves of the required type is well developed.

3.1.1 Steam Generator

The general arrangement of the NGNP HTS developed for this study with the SG in the primary system (based on the SC-MHR arrangement) using a single primary loop is shown in Figure 3-3. The steam generator is housed in a pressure vessel with its thermal center located below that of the reactor core.

The steam generator, Figure 3-4, is a vertically oriented, up-flow boiling, cross-counter flow, once-through shell-and-tube heat exchanger that utilizes multiple tube, helically-wound tube bundles. The design employs two bundles, a lower bundle and an upper bundle. The lower bundle contains economizer, evaporator and initial superheater sections and uses 2¼Cr – 1Mo material for the tubing. The upper bundle contains a finishing superheater section and uses Inconel 617 material for the tubing. A bimetallic weld is required to join the two tube materials.

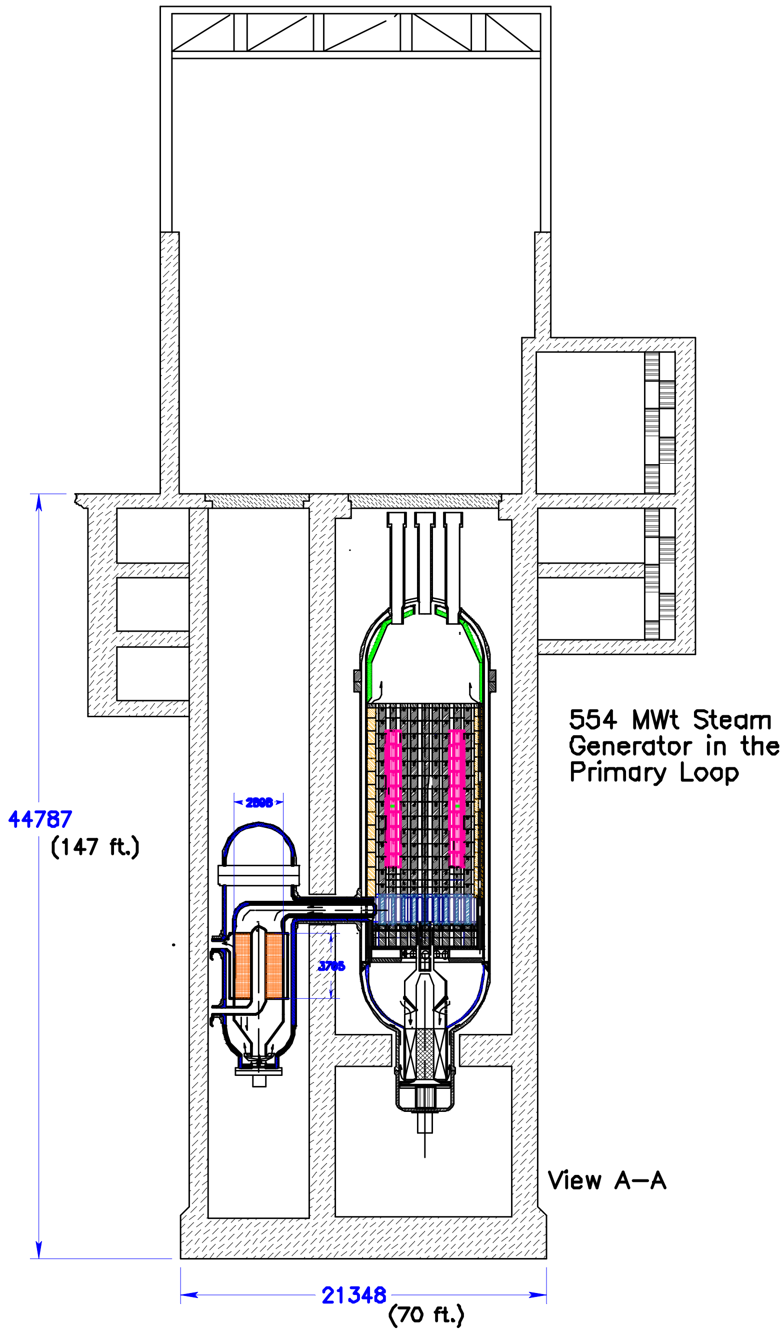


Figure 3-3. NGNP HTS Arrangement with SG in the Primary Loop

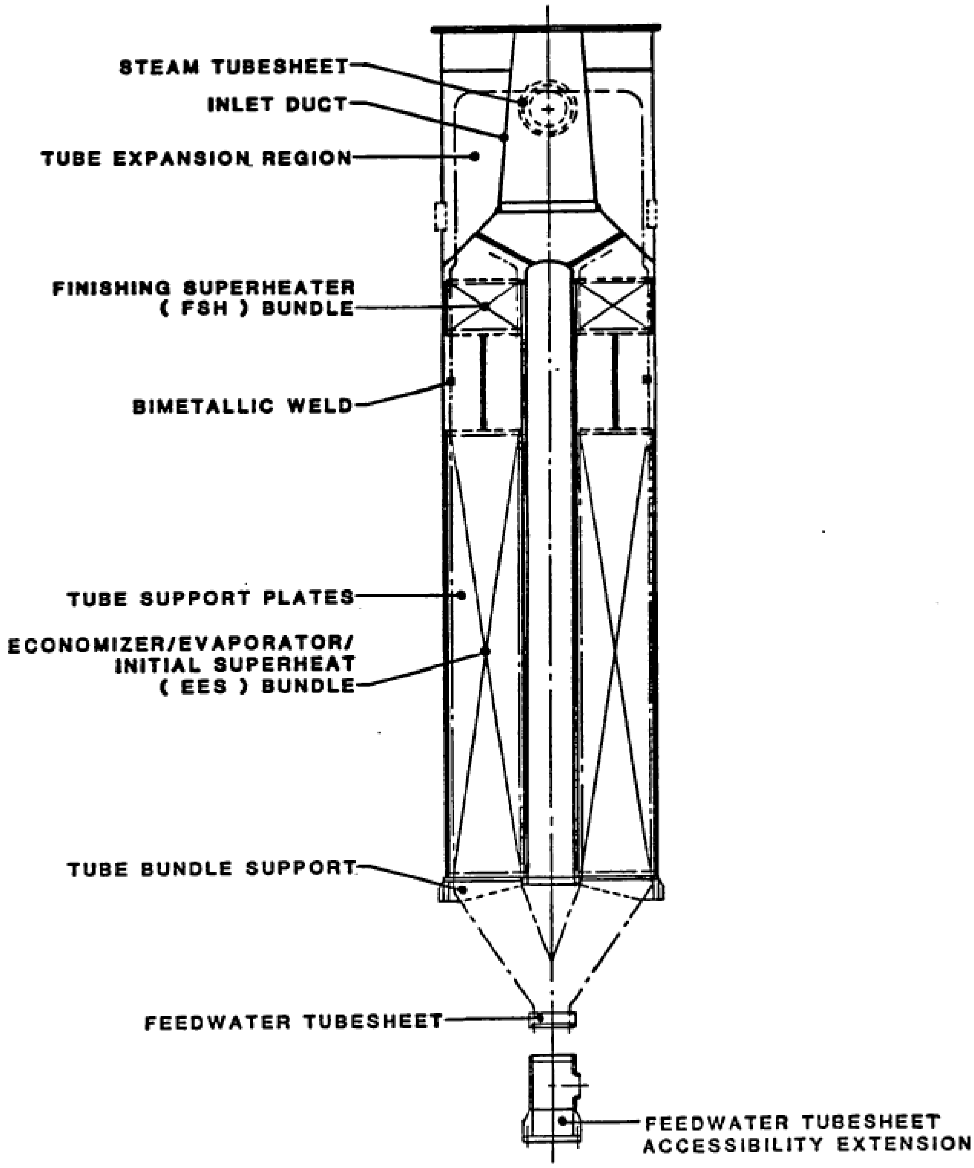


Figure 3-4. SG Configuration

The bimetallic weld is located between the two bundles. Previous HTGR steam generator designs used 2¼ Cr – 1Mo material for economizer, evaporator and initial superheater tubing and Incoloy 800H for the finishing superheater section. Developing a bimetallic weld between 2¼Cr – 1Mo and Inconel 617 is not expected to be any more difficult than a bimetallic weld between 2¼Cr – 1Mo and Incoloy 800H.

The design provides access for tube leak detection and plugging from both ends of each tube. In addition, the design makes possible the removal and replacement of the steam generator tube bundle through a removable upper vessel head. SG design data, for both the single loop and dual loop options is provided in Table 3-1. The SG design data in Table 3-1 indicate acceptable SG operating temperatures for the SG tubing materials when Inconel 617 is used as the material of construction for the finishing superheater.

3.1.2 Rankine Cycle Options

An evaluation performed by Stone & Webster Engineering Corporation (SWEC) for selection of the SC-MHR steam turbine, indicates the non-reheat SC-MHR steam cycle would result in excessive moisture in the low pressure turbine [SWEC 1991]. For the NGNP, this issue could be resolved through the use of a reheat cycle. With the SG in the primary system, two options for providing reheat have been considered:

- Reheating steam using primary system nuclear heat by incorporating a reheater in the primary loop, either as a heat exchanger in a separate vessel or as a separate section in the steam generator. This option would require two additional steam line penetrations in the primary system, one for returning steam from the turbine plant to the primary system for reheating and another for returning the reheated steam from the primary system to the turbine plant.
- Use of steam-to-steam reheat as is done in LWR plants by extracting steam from the high pressure turbine to reheat the main steam prior to entering the low pressure turbine.

Both of these options would require the engineering design development of an appropriate reheat heat exchanger. The first option of putting the reheater in the primary system would involve additional steam line penetrations of the primary system boundary, space for routing of the steam lines within the primary boundary potentially requiring a primary boundary size increase, use of nuclear grade codes and standards applicable for primary system components and be subject to nuclear regulatory requirements. Based on these considerations, putting a reheater into the primary system is judged to be the more expensive option and is not recommended. The most appropriate design option for providing steam reheat is judged to be use of a steam-to-steam reheater in the power conversion system. This option would require the engineering design development of an appropriate reheat heat exchanger but this is judged to be cost effective due to the resultant higher cycle efficiency, potentially less low-pressure turbine engineering design development and longer low-pressure turbine blade life.

Table 3-1. Design Data for SG in Primary Loop

	Single Primary Loop	Dual Primary Loops
Heat Duty, MW	547	274
Bundle OD, mm	2896	2134
Bundle ID, mm	823	838
Bundle Height, mm[1]	3793	3857
He inlet Temperature, °C	900	900
He Outlet Temperature, °C	480	480
He Flow Rate, kg/sec	250	125
He Inlet Pressure, MPa	7	7
He Pressure Drop, kPa	24	24.6
Water Inlet Temperature, °C	200	200
Steam Outlet Temperature, °C	538	538
Water Flow Rate, kg/sec	216.	108
Feedwater Inlet Pressure, MPa	18.2	18.2
Steam Outlet Pressure, MPa	17.2	17.2
Number of Tubes	441	218
Economizer Tube Material	2¼ Cr – 1 Mo	2¼ Cr – 1 Mo
Evaporator Tube Material	2¼ Cr – 1 Mo	2¼ Cr – 1 Mo
Initial Superheater Material	2¼ Cr – 1 Mo	2¼ Cr – 1 Mo
Finishing Superheater Material	Inconel 617	Inconel 617
Tube Mid-wall temperatures, °C		
At feedwater inlet	332	331
At evaporator inlet	483	483
At evaporator exit	551	552
At initial superheater inlet	551	551
At finishing superheater inlet	597	596
At finishing superheater outlet	720	719

[1] *Height of tube bundle active heat transfer surface. Does not include the vertical separation between 2¼Cr-1Mo bundle and the Inconel 617 bundle. The bi-metallioc weld is located in this vertical separation.*

3.2 Steam Generator in Secondary Loop

3.2.1 HTS Configuration

Two alternative HTS configurations with the SG in a secondary loop were selected for consideration. The first HTS configuration (HTS Configuration I) has a single primary loop containing a 612-MWt IHX to supply heat to the secondary loop. The secondary loop supplies a portion of the hot secondary helium to the hydrogen process heat exchanger. The balance of the hot secondary helium is mixed with the helium returning from the hydrogen process prior to entering the SG. In this configuration, the SG is in series with the hydrogen plant in the secondary loop, thus it is referred to as the “serial HTS configuration”). Figure 3-5 provides a flow schematic of this HTS configuration. The second configuration (HTS Configuration II) has two parallel primary loops, one that contains a 65-MWt IHX to supply heat via a secondary loop to the hydrogen production facilities and a second primary loop that contains a 547-MWt IHX to supply heat to a secondary loop containing the SG. Figure 3-6 shows a schematic diagram of this HTS configuration, which is referred to as the “parallel primary loop configuration”.

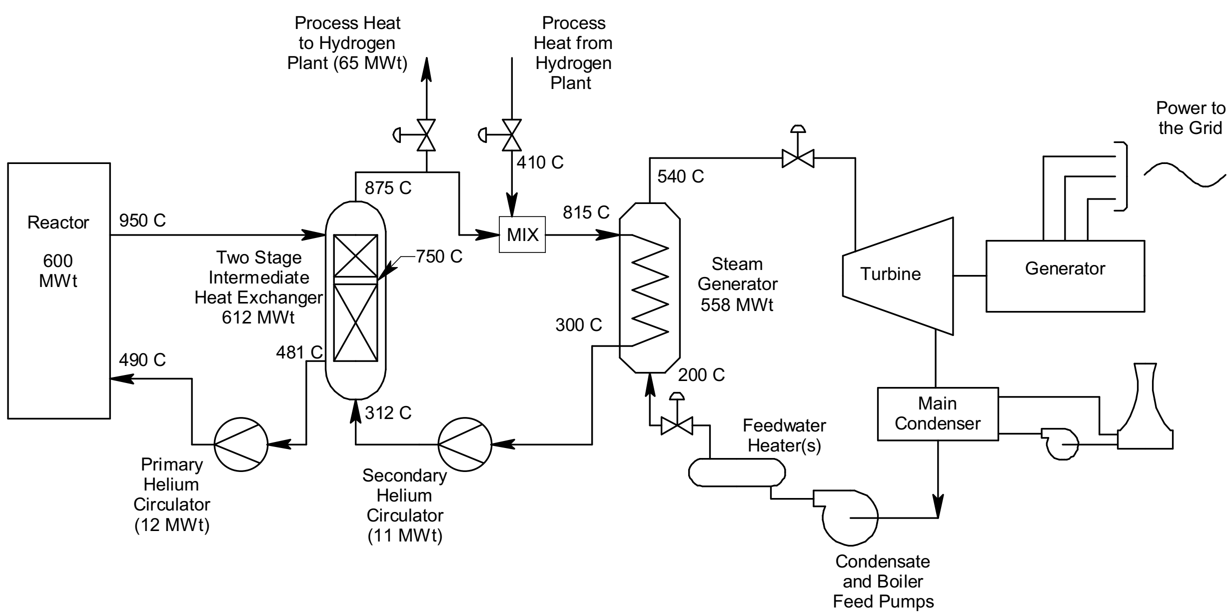


Figure 3-5. SG in Secondary Loop – Serial HTS Configuration (Configuration I)

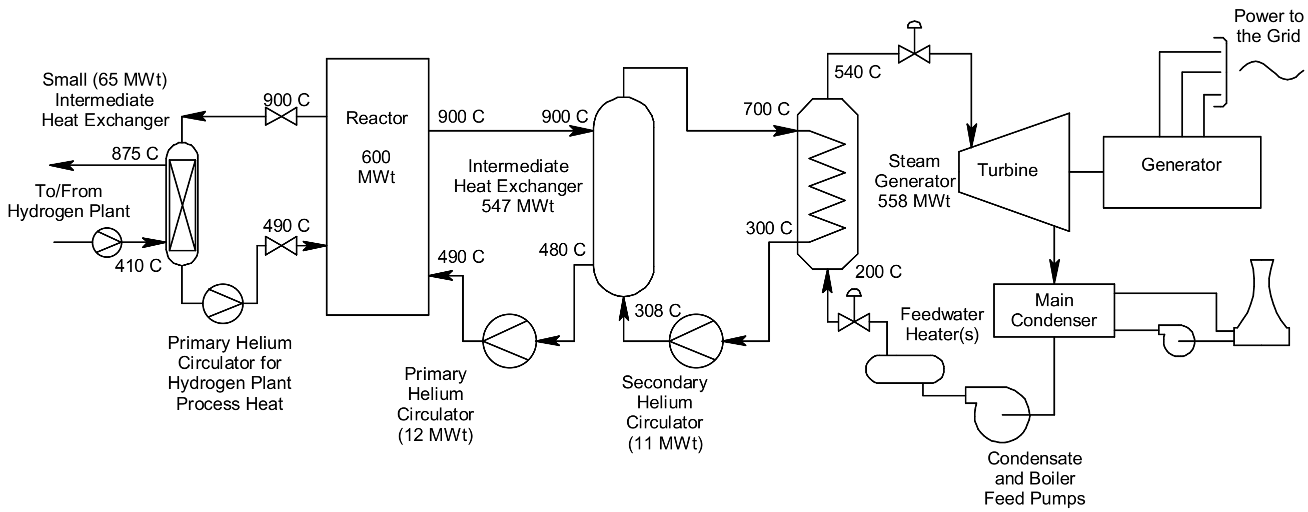


Figure 3-6. SG in Secondary Loop – Parallel Primary Loop Configuration (Configuration II)

Figure 3-5 shows a two-stage IHX in the primary loop, a high temperature stage for primary coolant temperatures from 900°C to 750°C and a low temperature stage for primary coolant temperatures from 750°C to 481°C. The 750°C temperature was selected for the inlet to the low temperature stage to stay within the temperature limit for alloy 800H in Section III of the ASME code but, designs based on using 800H were also studied where the inlet temperature was increased to 800°C. The high temperature stage is to be replaceable and would have a design lifetime shorter than the plant lifetime. The design lifetime of the lower temperature stage would be the plant design lifetime (60 years). A two-stage IHX could also be used for the two parallel primary loop configuration, but this may not be necessary because, with the 700°C IHX secondary outlet temperature design condition given in Figure 3-6, an IHX design having a 60-year lifetime might be possible [GA 2008].

The primary benefit of locating the SG in a secondary circuit is the additional barrier provided by the IHX for control of radionuclides. A particular radionuclide control benefit provided by having the SG in a secondary loop is the reduction in probability of introducing water into the primary system which can cause oxidation of the core graphite and hydrolysis of the coated particle fuel to release radionuclides. This benefit does, however, entail significant additional costs associated with the following:

- Engineering design development of an IHX with a capacity on the order of 600 MWt which may be more challenging than an IHX with a capacity on the order of 65 MWt.

Either size may require provisions for periodic replacement of sections having high operating temperatures but, replacement of all the heat exchanger surfaces for a 65 MWt unit would be less cost prohibitive than for a 600 MWt unit.

- IHX capital cost
- Capital cost of additional systems, structures and components (SSCs) The additional SSCs include the secondary system circulator, secondary system heat transport fluid service systems (purification, storage, and transfer) secondary system piping, secondary system controls, secondary system housing and support structures, etc.
- O&M costs for the additional SSCs.
- Engineering development cost of isolation valves between the primary and secondary to isolate the secondary from the primary. Isolation valves are necessary to realize the potential benefits of incorporating SGs in a secondary system. The secondary system needs to operate at slightly higher pressure than the primary and under this condition, if the SG leaked into the secondary, isolation valves would be required to prevent the secondary moisture from entering the primary. Or, if the secondary system de-pressurized, isolation valves would be required to prevent radionuclides from leaking into the secondary. There are no currently available large size He isolation valves. There are, however, suitable isolation valves available for steam-water secondary systems.
- Capital cost and O&M cost for the isolation valves.

Other potential benefits of incorporating the SG in a secondary system include:

- The potential for reduced SG cost due to the possibility for (1) using commercial codes and standards for the SG, (2) the SG not needing to be configured within tight confines and (3) the SG not needing to be subject to nuclear regulatory requirements. To realize these advantages would require nuclear grade isolation valves between the primary and secondary circuits.
- Incorporating a reheater in a secondary circuit (in series with the SG) should be far easier to accomplish than incorporating a reheater in the primary circuit. The incentive for such a reheater would be to reduce moisture in the low-pressure turbine and to increase power conversion efficiency.
- Potential for use of other alternative heat transport fluids in the secondary circuit. Use of CO_2, for example, as the secondary heat transport fluid might enable utilization of steam generation and power conversion experience and technology from the Advanced Gas Reactor (AGR) program in the U.K. There is, however, an inconsistency that would require resolution to make this possible. The maximum AGR CO_2 SG inlet temperature (~640°C) is somewhat lower than the secondary system temperatures indicated in Figure 3-6.

3.2.2 Steam Generator

For the current study, helium has been assumed for the secondary fluid for design of the secondary system SGs based primarily on the following considerations:

- For the configuration with the hydrogen process heat supply in series with the secondary system heat supply (Figure 3-5), the secondary heat transfer fluid needs to be the same as the fluid used to interface with the hydrogen process which currently has been chosen to be helium.
- Helium is compatible with the high temperature conditions used in the Figure 3-5 configuration.
- For control of radionuclides, the secondary loop pressure should be slightly higher than the primary system pressure such that any leakage through the IHXs is into, rather than out of, the primary system. Helium would be the most compatible secondary fluid for this leakage condition.

The following other system design conditions were assumed based on the same considerations identified above for the SG in the primary circuit:

- SG designs for dual secondary loops, as well as for a single secondary loop (in case high circulator capacity poses too much risk)
- No by-pass in secondary loop to reduce SG inlet temperature
- No reheater in secondary loop (use steam-to-steam reheater in tertiary power conversion system).
- Secondary system SGs of the same type and general arrangement as the SG design described above for the SGs located in the primary system (vertically oriented, up-flow boiling, cross-counter flow, once-through shell-and-tube, multiple tube, helically wound tube bundles).

The chosen type of SG design could be located inside the radionuclide containment boundary should secondary system isolation valves prove impractical and because:

- The design is completely compatible with helium heat transfer fluid operating conditions
- The design is not likely to carry a significant cost premium because of its efficient design features.

SG design data for the parallel primary loop configuration shown in Figure 3-6, for both single and dual primary loop options, are provided in Table 3-2. SG design data for the serial HTS

Table 3-2. Design Data for SG in Secondary Loop – Parallel Primary Loop Configuration

	Single Primary Loop	**Dual Primary Loops**
Heat Duty, MW	558	279
Bundle OD, mm	3962	2743
Bundle ID, mm	762	762
Bundle Height, mm[2]	5289	5587
He inlet Temperature, °C	700	700
He Outlet Temperature, °C	300	300
He Flow Rate, kg/sec	268	134
He Inlet Pressure, MPa	7	7
He Pressure Drop, kPa	17	21.2
Water Inlet Temperature, °C	200	200
Steam Outlet Temperature, °C	538	538
Water Flow Rate, kg/sec	221.	110
Feedwater Inlet Pressure, MPa	19.1	19.1
Steam Outlet Pressure, MPa	17.2	17.2
Number of Tubes	440	218
Economizer Tube Material	2¼ Cr – 1 Mo	2¼ Cr – 1 Mo
Evaporator Tube Material	2¼ Cr – 1 Mo	2¼ Cr – 1 Mo
Initial Superheater Material	2¼ Cr – 1 Mo	2¼ Cr – 1 Mo
Finishing Superheater Material	Incoloy 800H	Incoloy 800H
Tube Mid-wall temperatures, °C		
At feedwater inlet	244	245
At evaporator inlet	398	399
At evaporator exit	450	451
At initial superheater inlet	450	451
At finishing superheater inlet	497	498
At finishing superheater outlet	616	617

configuration shown in Figure 3-5, for both single and dual primary loop options are provided in Table 3-3. The SG design data in Tables 3-2 and 3-3 indicate acceptable SG operating temperatures for the identified SG tubing materials of construction.

[2] *See Foot Note 1 on Table 3-1.*

Table 3-3. Design Data for SG in Secondary Loop– Serial HTS Configuration

	Single Primary Loop	**Dual Primary Loops**
Heat Duty, MW	558	279
Bundle OD, mm	3353	2743
Bundle ID, mm	762	762
Bundle Height, mm[3]	5563	4527
He inlet Temperature, °C	815	815
He Outlet Temperature, °C	300	300
He Flow Rate, kg/sec	208	104
He Inlet Pressure, MPa	7	7
He Pressure Drop, kPa	23.4	11.7
Water Inlet Temperature, °C	200	200
Steam Outlet Temperature, °C	538	538
Water Flow Rate, kg/sec	221	110
Feedwater Inlet Pressure, MPa	18.6	18.8
Steam Outlet Pressure, MPa	17.2	17.2
Number of Tubes	442	218
Economizer Tube Material	2¼ Cr – 1 Mo	2¼ Cr – 1 Mo
Evaporator Tube Material	2¼ Cr – 1 Mo	2¼ Cr – 1 Mo
Initial Superheater Material	2¼ Cr – 1 Mo	2¼ Cr – 1 Mo
Finishing Superheater Material	Incoloy 800H	Incoloy 800H
Tube Mid-wall temperatures, °C		
At feedwater inlet	245	244
At evaporator inlet	415	413
At evaporator exit	486	481
At initial superheater inlet	487	482
At finishing superheater inlet	539	534
At finishing superheater outlet	671	667

[3] *See Foot Note 1, Table 3.-1*

4. COMPARISON OF STEAM GENERATOR OPTIONS

4.1 Plant Economics

An insight into the impact of the alternative HTS configurations on plant economics can be gained from consideration of the HTS capital equipment requirements and the associated equipment costs relative to total plant costs. Figure 4-1 is a schematic of the major equipment items for the alternative HTS configurations identified in Section 3. The quantities of major equipment items required for each of the options is also given in Figure 4-1.

[GCRA 1993] contains capital equipment costs for modular high temperature gas-cooled reactor steam cycle (SC-MHR) plants. Capital costs, in terms of 1992$, are identified for a one-module 450-MWt SC-MHR prototype plant as well as for follow-on 4-module plants. The one-module SC-MHR plant has a single primary HTS loop containing a single SG supplying steam to a non-reheat Rankine cycle power generation system. The basic arrangement of the SC-MHR HTS for the one-module plant is the same as that indicated in Figure 4-1, Sub Figure IIIa, but without the primary loop containing the IHX to supply heat to a hydrogen production process.

Table 4-1 contains the direct costs for the SC-MHR one-module plant HTS equipment from [GCRA 1993] The SC-MHR HTS capital equipment costs, including the SG pressure vessel and supports, total $51.72 million in 1992 dollars. The total direct capital cost for the SC-MHR one-module plant is $395.18 million, in 1992 dollars. This data indicates that the SC-MHR HTS equipment represents about 13% of the total direct capital costs. This same percentage, 13%, for the HTS would be expected to apply the total plant capital cost where the total plant capital cost is the sum of the direct and indirect costs plus interest costs during construction.

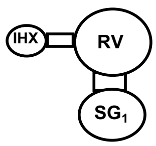
The following assumptions were made to develop a rough order of magnitude (ROM) capital cost estimates for the alternative HTS configurations shown schematically in Figure 4-1 using the cost data in Table 4-1:

- A scaling factor of 0.65 applies (for estimating HTS capital cost of systems with different power capacities)
- The capital costs of primary system heat exchangers having equivalent heat ratings are equivalent regardless of whether the heat exchanger is of a shell and tube design or a PCHE design. Although PCHEs are more compact that shell-and-tube HEs, they are more expensive to manufacture so, for the ROM cost estimates, the two types were assumed to have equivalent costs for equivalent capacities.

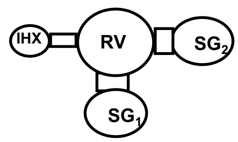
NGNP Indirect Cycle Configuration Options
Rankine Cycle Power Generation, Major Equipment Items

III. SG in Primary Coolant (PC) Loop

a. Single PC loop + parallel H2 IHX loop
b. 2 parallel PC loops + parallel H2 IHX loop



Sub Fig. IIIa.

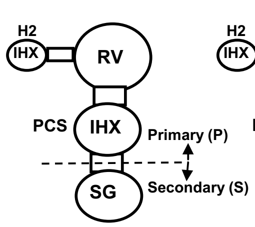


Sub Fig. IIIb

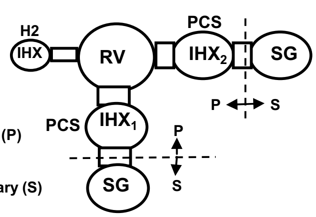
	Major Equipment Items	**Qnty**
Sub Fig. IIIa		
	Reactor Assembly	1
	SG & Circulator Assembly	1
	H2 IHX & Circulator Assembly	1
	Stm TG System	1
	Sum	4
Sub Fig. IIIb		
	Reactor Assembly	1
	SG & Circulator Assembly	2
	H2 IHX & Circulator Assembly	1
	Stm TG System	1
	Sum	5

II. SG in Secondary Loop

a. Single PCS loop + parallel H2 IHX loop
b. 2 parallel PCS loops + parallel H2 IHX loop



Sub Fig. IIa.

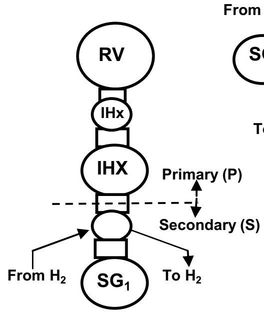


Sub Fig. IIb

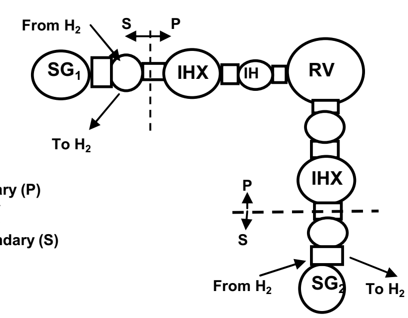
Sub Fig. IIa		
	Reactor Assembly	1
	PCS IHX & Circulator Assembly	1
	SG & Circulator Assembly	1
	H2 IHX & Circulator Assembly	1
	Stm TG System	1
	Sum	5
Sub Fig. IIb		
	Reactor Assembly	1
	PCS IHX & Circulator Assembly	2
	SG & Circulator Assembly	2
	H2 IHX & Circulator Assembly	1
	Stm TG System	1
	Sum	7

I. Staged IHX, SG in Secondary Loop, Process Heat in Series with SG

a. Single PCS loop, staged IHXs,
b. 2 PCS loops, staged IHXs



Sub Fig.Ia.



Sub Fig. Ib

Sub Fig. Ia		
	Reactor Assembly	1
	PCS Hot Stage IHX	1
	PCS IHX Cold Stage & Circ Assy	1
	H2 Process Mixing Chamber Assy	1
	SG & Circulator Assembly	1
	Stm TG System	1
	Sum	6
Sub Fig. Ib		
	Reactor Assembly	1
	PCS Hot Stage IHX	2
	PCS IHX Cold Stage & Circ Assy	2
	H2 Process Mixing Chamber Assy	2
	SG & Circulator Assembly	2
	Stm TG System	1
	Sum	10

Figure 4-1. Major Equipment Items in Alternative NGNP HTS Configurations

Table 4-1. 450 MWt SC-MHR One Module Plant HTS Equipment Costs

HTS Equipment Item	Cost, 92M$*
Main Helium Circulator	8.26
Steam Generator	20.17
HTS Internals	5.90
HTS Service System Equipment	2.83
Subtotal	37.16
HTS Installation Cost	0.16
HTS Installed Cost	37.31
SG Vessel & Supports	13.47
SG Vessel w/Installation Cost	14.41
Total SC-MHR HTS with SG Vessel	51.72
Correction for Inflation	
Ratio of Implicit Price Deflator, '92 - '07	1.3856
Single Loop NGNP SG HTS, 07M$	71.66
Correction for NGNP Size (0.65 scale factor)	
SC-MHR HTS Rating, MWt	450
NGNP HTS Rating, MWt	600
Single Loop NGNP SG HTS, '92M$	86.40

* Except as noted

The resultant ROM plant capital cost estimates for NGNP plants having the alternative HTS configurations summarized in Figure 4-1 are itemized in Table 4-2. The last column of Table 4-2 identifies the ROM effect of the plant capital cost component on product cost. Note that capital cost is only a part of the product cost. For example, if the capital cost component of the product cost was 50%, and if the capital cost component was to increase by 10%, the product cost would increase only 5%.

Table 4-2. Comparison of ROM Plant Direct Capital Costs for Alternative HTS Configurations

	Main HTS Primary Loop (See Note 1)				Main HTS Secondary Loop (See Note 1)				Process Heat Loop			Plant (See Note 2 & 3)		
	HE Type	Nunber	HE Capacity, MWt	HTS Direct Capital Cost, '07M$	HE Type	Nunber	HE Capacity, MWt	HTS Direct Capital Cost, '07M$	Nunber of IHXs	IHX Capacity, MWt	HTS Direct Capital Cost,'07M$	Total HTS Capital Cost, '07M$	Total Plant Capital Cost, '07M$	Relative Cost Impact (See Note 4)
Reference MHTGR HTS	SG	1	450	71.7	--	--	--	0	0	0	0	71.7	547.6	1.11
NGNP with SG in Primary Coolant Loop (Configuration III)														
Singlle Main Loop	SG	1	600	86.4	--	--	--	0	1	65	20.4	106.8	660.2	1.00
Dual Main Loops	SG	2	300	110.1	--	--	--	0	1	65	20.4	130.5	683.9	1.04
NGNP with SG in Secondary Coolant Loop (Configuration II)														
Singlle Main Loop	IHX	1	600	86.4	SG	1	600	86.4	1	65	20.4	193.2	746.5	1.13
Dual Main Loops	IHX	2	300	110.1	SG	2	300	110.1	1	65	20.4	240.6	794.0	1.20
NGNP with SG in Secondary Coolant Loop (Configuration I)														
Singlle Main Loop	IHX - S1	1	220	45.0	SG	1	600	86.4	0	0	0			
	IHX - S2	1	380	64.2	SG	1	600	86.4	0	0	0	195.6	749.0	1.13
Dual Main Loops	IHX - S1	2	110	57.4	SG	2	300	110.1	0	0	0			
	IHX - S2	2	190	81.8	SG	2	300	110.1	0	0	0	249.3	802.7	1.22

Notes:

1. For the purposes of estimating approximate capital costs, the heat duty of the main heat exchangers was assumed to have a nominal rating of 600 MWt

2. "Plant" as used in this table includes all of the SSCs for electricity generation, process steam production and process heat production but excludes SSCs associated with transport of process heat to the hydrogen production facility and the SSCs for hydrogen production.

3. Capital cost as used here is only the direct capital cost component (indirect costs are not included).

4. Relative to 600 MWt plant with single SG in singe main primary loop.

The results in Table 4-2 indicate the following:

- For a NGNP plant with a single main primary loop containing a SG, the ROM plant capital component of production costs would increase by about 11% if the plant capacity was reduced from 600 MWt to 450 MWt.
- The ROM effect of the capital cost component on product cost of using dual SG primary loops with each loop having ½ of the plant capacity is estimated to be about a 4% increase relative to using a single SG primary loop. Note that there would also be an increase in the O&M component of product cost due to the added equipment so the total product cost would be expected to increase on the order of this same percentage amount.
- The ROM effect of the capital cost component on product cost of using a single main primary loop containing an IHX coupled to a single secondary loop containing a SG is about a 13% increase relative to using a single SG primary loop. Again, the total product cost would be expected to increase on the order of this same amount.
- The ROM effect of the capital cost component on product cost of using dual main primary loops each containing an IHX coupled to a secondary loop containing a SG is about a 20% increase relative to using a single SG primary loop. Again, the total product cost would be expected to increase on the order of this same amount.
- The ROM effect of the capital cost component on product cost of using a single main primary loop containing staged IHXs coupled to a single secondary loop containing a SG and a take off for (and a return line for) hydrogen process heat is about a 13% increase relative to using a single SG primary loop. Again, the total product cost would be expected to increase on the order of this same amount.
- The ROM effect of the capital cost component on product cost of using dual main primary loops each containing staged IHXs coupled to a secondary loop containing a SG is about a 22% increase relative to using a single SG primary loop. Again, the total product cost would be expected to increase on the order of this same amount.

The economic significance of these relative cost differences can be qualitatively evaluated using the economic comparison of alternative plants contained in [GCRA 1993]. This reference shows the electricity busbar generation cost for a mature 4x450 MWt MHTGR steam cycle plant (i.e., a SC-MHR) to be approximately equivalent to that for equivalently sized coal fired plants, either Pulverized Coal plants or Integrated Gasification Combined Cycle (IGCC) plants. [GCRA 1993] also shows Combined Cycle Combustion Turbine (CCCT) plants to have lower generation costs than either the SC-MHR or coal plants. There has, however, been significant real escalation (cost increase above average rate of inflation) in the cost of natural gas since [GCRA 1993] was prepared to the point where CCCT plants are no longer an economic choice for new generation capacity additions.

With the exception of the intensifying need to abate the environment impact of coal plants, no significant cost escalations are known to have occurred that would significantly skew the costs of coal and nuclear plants relative to each other. Assuming there has been relatively little real cost escalation difference between coal plants and nuclear plants, the relative economics between the coal plants and an SC-MHR plant should be relatively the same except for coal plant cost increases to meet environmental requirements (e.g., costs for CO_2 sequestration, a carbon tax, or other). With this assumption and the [GCRA 1993] busbar cost data, the Table 4-2 relative cost differences indicate the following:

- Adjusting the reactor power from 450 MWt to 600 MWt for a single primary loop plant with the SG in the primary loop (Configuration III) would cause the SC-MHR busbar cost to go from being marginally less economic (than the coal plants as shown in [GCRA 1993]) to being marginally more economic than the coal plants. Coal plant cost adders needed to meet environmental requirements would enhance the SC-MHR competitiveness relative to the coal plants.
- A dual primary loop SC-MHR plant with the SGs in the primary loops would have a busbar generation cost about equal to equivalently sized coal plants without added environmental costs. However, the dual loop SC-MHR plant should still have an economic advantage relative to coal plants when costs are added to the coal plants to meet environmental requirements.
- SC-MHR plants with with the SGs in secondary loops (Configurations I or II) would probably not be competitive with equivalently sized coal plants even if the coal plant costs were increased (a few percent as expected) to meet environmental requirements.

In the foregoing, the buildings and structures costs were assumed to be the same for the three HTS alternative configurations. However, as part of this study and the companion IHX and HTS alternatives study [GA 2008], URS Washington Division developed Reactor Building layouts for the each of these configurations as listed in Table 4-3. In layouts 1 through 4, the SGs are in secondary loops. These alternatives are variations on HTS configurations I and II. In RB layout 5, the SGs are in primary loops. In this layout, there are two primary loops with SGs with each SG sized for 300-MWt heat transfer duty, and a parallel primary loop to deliver heat to the hydrogen process via a 65-MWt IHX. Figure 4-2 shows the layout prepared for the HTS configuration with the SGs in the primary loop.

Table 4-3. Key Characteristics of RB Design Alternatives

Case	Description	RB Dimensions	
		Diameter	Embedment Depth
Reference Design Parallel primary loops	Includes one primary loop with a direct Brayton cycle power conversion system and a second primary loop to transport heat to a 65-MWt IHX that transfers the heat to a secondary loop via which the heat is transported to the hydrogen processes	28,960 mm (95 feet)	42,670 mm (140 feet)
Layout 1 Parallel primary loops with two PCS loops	Each loop contains one compact-type IHX with one SG immediately outside the RB in the secondary loop. Each IHX and SG is sized for ~273 MWt. There is a separate dedicated primary having a small 65-MWt IHX for transferring heat to the hydrogen processes.	24,160 mm (79 feet)	44,960 mm (148 feet)
Layout 2 Parallel primary loops with two PCS loops	Same as alternative 1 except that each IHX and SG pair is located at the same radial distance from the reactor centerline.	29,950 mm (98 feet)	44,960 mm (148 feet)
Layout 3 Parallel primary loops with four PCS loops	Each PCS loop has a helical-coil-type IHX sized for ~150-MWt. The secondary system has a two-loop arrangement with one SG sized for ~300 MWt in each loop Thus, two IHXs are providing heat to each SG. There is a separate dedicated primary loop having a small 65-MWt IHX for transferring heat to the hydrogen processes.	28,350 mm (93 feet)	52,430 mm (172 feet)
Layout 4 Serial configuration with one primary loop	The single primary loop contains one two-stage compact IHX with one SG in the secondary loop. The IHX and SG are sized for ~600 MWt	24,380 mm (80 feet)	44960 mm (148 feet)
Layout 5 Parallel primary loops with SG in primary loop	Each PCS loop has one SG sized for 300MWt heat transfer. There is a separate dedicated primary loop having a small 65-MWt IHX for transferring heat to the hydrogen processes.	20,960 mm (69 feet)	44,960 mm (148 feet)

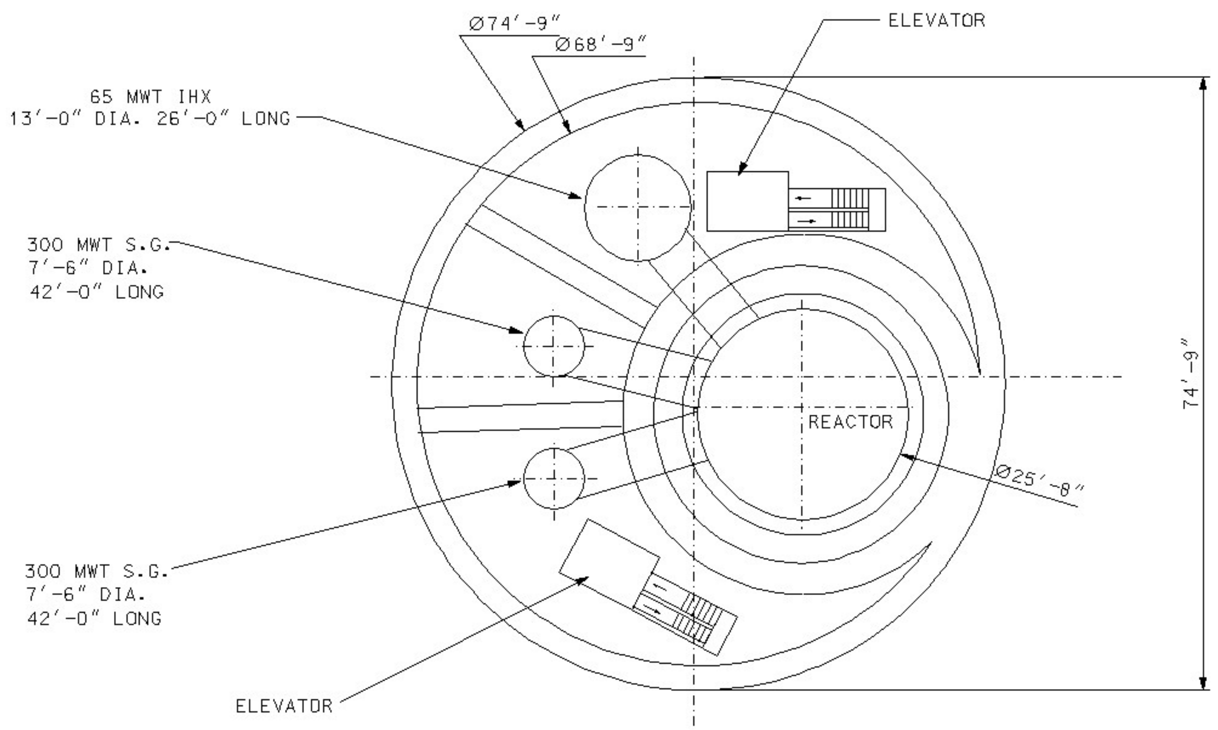


Figure 4-2. Parallel Primary Loops with Steam Generators in the Primary Loops

The relative cost of each of the RB layouts was evaluated with respect to the NGNP pre-conceptual RB design presented by the GA Team in [PCDSR 2007]. The relative costs were estimated based on the following assumptions.

- All constructions costs are 2007 dollars
- The "Greenfield" site is based in INL – Idaho
- The footprint for the NGNP Reactor Building prototype was used to scale capital costs for the alternative design building and concrete silo configurations
- All mechanical, architectural, electrical and steel liner costs are extrapolated costs based on the total volume of the below grade structure
- Capital costs reflect building costs only and exclude MHR plant equipment. Site-work includes lava rock excavation up to depths of 172'-00"
- Capital cost productivity for nuclear safety class 1 construction is reflected in all costs

- Limitations on ease of constructability of the concrete silos increases as the silo depth increases
- Physical constraints and increase costs are anticipated as the depth of the silo escalates
- Structural costs for the building decrease as the footprint of the above ground structure decreases due to reduction in the diameter of the concrete silo's footprint
- The indirect costs account for construction services, home office engineering and services, field office engineering and services, owner's cost
- Excludes initial core costs

Table 4-4 summarizes the relative capital costs of the different HTS configurations.

Table 4-4. Summary of Capital Costs Impact for RB Alternatives

Scope of Work	Prototype ($M)	Layout 1	Layout 2	Layout 3	Layout 4	Layout 5
Site-work	8.6	-11%	7%	13%	-27%	-45%
Concrete	38.9	-13%	-2%	-0.5%	-19%	-32%
Structural Steel	10.1	0%	0%	0%	-27%	-45%
Mechanical Systems	2.2	0%	0%	0%	-27%	-45%
Lighting	0.4	0.0%	0.0%	0.0%	-26%	-44%
Steel Liner	13.0	-8%	5%	9%	-27%	-45%
Total Direct Costs	73.2	-9%	0.6%	3%	-23%	-38%
Indirect Costs	181.2	-10%	1%	-5%	-28%	-43%
Total	254.4	-10%	1%	3%	-23%	-38%

The NGNP Reactor Building cost information in Table 4-4 indicates that:

- The RB for any of the alternatives with SGs in secondary loops will be more costly than for an HTS configuration with dual primary loops and the SGs in the primary loops
- The RB capital cost for the dual-primary-loop configuration with the SGs in the primary loops was estimated to be 38% lower than the RB capital cost for the reference plant desgn given in [PCDSR 2007].

These results reinforce the conclusions reached above on the relative economic competitiveness of SC-MHR plants compared to coal plants. Conclusions relevant to commercial plants from these relative economic results are as follows:

- The most economic HTS configuration for a commercial plant based on the NGNP would be a single primary main loop containing a single SG and circulator.

- If the required circulator capacity is excessive for a single circulator in a single SG primary loop plant, dual circulators in the single loop could be used, or dual SG primary loops could be used. A dual primary loop HTS configuration with each loop containing a SG should be competitive with alternative types of steam-electric co-generation plants.
- The commercial plant economics are not expected to be competitive for a plant based on the NGNP having a single SG secondary loop coupled to single IHX primary loop due to the significantly increased capital + O&M cost and decreased availability (relative to the single SG primary loop concept).
- The commercial plant economics for a plant having dual IHX primary loops each coupled to a secondary SG loop are even less attractive than single IHX loop concept (greater capital + O&M and lower availability).
- Economics of commercial plants having staged IHXs primary loops, coupled to secondary SG loops with take-off H_2 process heat are expected to be about the same as the non-staged IHX HTS options.

These ROM economic results and conclusions only indicate trends. More complete design definition(s) is/are needed to develop more comprehensive cost estimates to enable more definitive economic analyses.

4.2 Plant Operation and Control

This section discusses reactor protection and control system conceptual designs, as they relate to NGNP steam plant configurations discussed in Section 3.

The unique inherent features of the Modular Helium Reactor (MHR) assure protection of the general public against fission product release from reactor core loss-of-cooling events. In addition, the inclusion of a safety-related Reactor Protection System and non-safety Investment Plant Control Data and Instrumentation Systems (PCDIS) provide a “defense in depth” strategy that ensures the MHR’s inherent loss-of-cooling protection will be vary unlikely. This approach is required for modern nuclear power plants. Also related to a complete “defense in depth” protection strategy are the Essential AC Electric System and the Essential DC Electric System, as well as other plant systems, such as the Reactor System, which contain end-action hardware to perform safety-related and non-safety actions.

4.2.1 Reactor Protection System and Investment Protection System

The HTS configurations discussed in Section 3 will each provide reactor protection and investment protection actions as follows:

- Detect and provide corrective action in event of changes in neutron flux, primary coolant flow rate, and temperature indicate neutron flux elevations in the reactor beyond the range of normal reactor operation.
- Detect and provide corrective action if changes in the Reactor Building (including changes in temperature, pressure and radiation levels) indicate the presence of primary coolant at levels that could potentially expose the general public to low-level radiation effects.
- Detect and provide corrective action if conditions of pressure, temperature or flow indicate an interruption of normal cooling functions.
- Detect and provide corrective action if upset of reactor power utilization processes creates a condition which could damage reactor and primary coolant containment components.
- Detect and provide corrective action if conditions of pressure and temperature, within and around the Vessel System (VS) primary coolant boundary, indicate a level of operation that exceeds the normal VS design levels.
- Detect and provide corrective action if conditions of environment or service to the reactor system indicate potential interruption of processes necessary to protect the reactor (for example non-1E electric systems) and are not suited for a particular environmental event. Conditions such as an earthquake fall into this category.

In addition to the automatic actions above, the Protection Systems also provide information to the reactor operator as part of the Control Room (CR) interface, discussed in Section 4.2.2 and Section 3.10 of [PCDSR 2007]. This reference also provides a list of additional Protection System Design requirements which must be applied to any of the NGNP plant designs.

4.2.1.1 Design Basis Events

Specific events associated with Protection System actions, such as reactor trip, SCS startup, Reactor Building Isolation, or steam generator isolation, are each referred to as a Design Basis Event (DBE). DBEs are within the “beyond design” cut-off of 1×10^{-5} occurrences per plant year, and will result in corrective actions by the Protection System. In previous MHR Steam Plant designs, these events were classified as “safety-related” or “non-safety,” depending on the need for “safety-related” end-actions. Table 4-5 and Table 4-6 show DBEs for the various HTS configurations discussed in Section 3. The Roman numerals are marked with the DBEs particular to one or two of the HTS configurations.

I. Steam generators in secondary loops, with IHXs for both the SG loops and the hydrogen plant.

II. Steam generators in secondary loops with a small dedicated IHX for the hydrogen loop and larger, dedicated IHXs for each steam generator.

III. Steam Generators in primary loops with a small dedicated IHX for the hydrogen loop.

Table 4-5. NGNP Design Basis Events for Reactor Protection System

DBE NUMBER	"SAFETY-RELATED" DESIGN BASIS EVENTS
1	Rapid, sustained control rod withdrawal
2	Slow, sustained control rod withdrawal
3	Loss of primary helium circulation
4	Turbine trip/ Loss of offsite power
5	Total loss of FW flow/ condenser vacuum
6	Rapid depressurization of primary helium to Reactor Building
7	Steam leak to primary or secondary coolant **(III)** or **(I)** & **(II)**
8	Slow primary coolant leak to Reactor Building (TBD variations)
9	Loss of secondary helium circulation **(I)**, **(II)**
10	Rapid depressurization of secondary loop **(I)**, **(II)**
11	Leak/ detection of radioactivity from primary to secondary loop **(I)**, **(II)**
12	Moisture ingress to primary coolant **(III)**

In Table 4-5, the events are classified as "safety-related" because a control rod trip or isolation of the Reactor Building might occur as a result of any of these events. Control rod trip and Reactor Building isolation are both NGNP "safety-related" end-actions. The DBEs in Table 4-6 do not require "safety-related" end-actions.

Table 4-6. NGNP Design Basis Events for Investment Protection System

DBE NUMBER	“NON-SAFETY” DESIGN BASIS EVENTS
13	Detection of radioactivity in hydrogen plant process loop **(III), (II)**
14	Loss of hydrogen plant helium circulator(s)
15	Loss of SCS reactor vessel cooling function
16	Detection of Shutdown Cooling Heat Exchanger (SCHE) leak
17	Helium pressurization system failure

Table 4-7 indicates instrumentation needed to obtain the process measurements for “safety-related” and “non-safety” protection actions. Instrumentation will be provided by the Investment Protection System (IPS), Reactor Protection System (RPS) and other reactor and steam plant systems. Table 4-7 shows expected measured parameters for input to the Protection System logic and the primary interface system for each. For example the reactor nuclear power measurement impacts both the reactor and concrete structure where the ex-core neutron detectors are placed. The “safety-related” instrumentation development efforts below will comprise an important part of the HTS control/protection design. These areas are reactor-specific and will affect each of the HTS configurations nearly equally.

- Nuclear Power Instrumentation — Power-range ex-core neutron detectors will be placed in six detector wells, equally spaced around the reactor vessel. Each well extends from the lower region of the reactor core to the refueling floor. Access to the detector wells is from the refueling floor. Neutron detection equipment includes Intermediate and Power Range Monitoring Channels, and Source Range Detector Assemblies and Monitoring Channels. The latter are retractable in-core devices operating at elevated temperatures. These entail a special NGNP development effort.
- Primary Helium Flow Rate — A method for deriving total mass flow rate for flow through the helium circulators was developed for the Fort St. Vrain plant. It is expected that a comparable method can be developed for the plants described above. The method must be applied to varying degrees in each of the HTS configurations, but the combined flow rate instrumentation package, which includes pressure, temperature, speed and Δp, is expected to be a common design.

Table 4-7. Protection System Process Measurements

Process Measurement	Instrumentation Required	Safety Designation	Interface System in SG Plants I, II or III
Reactor Power	Neutron Flux	Safety-related	Reactor System and Building **(All)**
Primary Helium Flow Rate	Primary Circulator Instrumentation — P, Δp and speed	Safety-related	Primary Circulator Systems **(All)**
Reactor Exit Temperature	Temperatures at Steam Generator Inlet or IHX Inlet	Safety-related	Steam Generator **(III)** or IHX Systems, **(I)** and **(II)**
Reactor Inlet Helium Temperature	Temperature at Reactor Inlet	Safety-related	Primary Circulator Systems **(All)**
Turbine Trip Parameter	Turbine Stop-Valve Status	Safety-related	BOP **(All)**
Moisture Content of Primary Coolant	Moisture Monitoring system	Safety-related **III** Non-safety **I & II**	Reactor Moisture Monitoring System **(III)**, BOP **(I & II)**
FW Flow Rate	FW Flow	Safety-related	BOP **(All)**
Reactor Building Temperature	Reactor Building Temperatures	Safety-related	Reactor Building **(All)**
Reactor Building Pressure	Reactor Building Pressures	Safety-related	Reactor Building **(All)**
Reactor Building Radiation Level	Radiation Detectors	Safety-related	Reactor Building **(All)**
IHX Secondary SG Helium Flow Rate	Circulator P, T, Δp and Speed	Safety-related	IHX Secondary Circulator System, **(I) and (II)**, NA in **(III)**
IHX Secondary Radioactivity Level	Radiation Detectors	Safety-related	IHX Secondary Circulator System, **(I) and (II)**, NA in **(III)**
He Leak to SCHE Water – Pressure increase detection	SCHE Cooling Water Pressure	Non-safety	Shutdown Cooling System **(All)**
Hydrogen Plant Measurements	(TBD)	Non-safety	Hydrogen Plant **(All)**
Small IHX Secondary Radioactivity Level	Radiation Detectors	Non-safety	Hydrogen Plant, **(II & III)**, NA in **(I)**

- Reactor Temperature Instrumentation — Development of a reactor temperature instrumentation scheme, with consideration of vessel penetration methods and refueling access, is another significant effort to be completed. The Russian program might contribute to this.

4.2.1.2 Design Basis Protection Transients

The Protection Systems incorporate setpoints, processed data, and protection-action “Request” pathways, plus end-action hardware to perform the necessary Protection System reaction to a DBE. The Protection System processors contain logic which initiates specific protection actions — this is called the Decision Logic. The Protection System’s 2-out-of-4 hardware implementation for these plants is the same as is explained in Section 3.10 of [PCDSR 2007].

Protection System transients occur when the decision logic requests a reactor trip or some other protection action. The reactor trip transient events fall into the broad categories below:

- An uncontrolled increase in neutron flux
- Detection of a primary coolant release directly into the Reactor Building
- Development of internal plant conditions which require interruption of the normal reactor cooling process, such as water-ingress (SG tube leak into primary coolant), significant escape of primary helium through leakage paths connected through the Reactor Building (secondary system radiation events), and loss of BOP heat removal capability (FW loss or condenser vacuum loss etc).
- An automatic action caused by an external event, such as a Turbine Trip following a loss-of-offsite-power, an earthquake, etc. which results in disruption of normal plant operation and which in turn could impair reactor cooldown without immediate reactor trip
- An operator initiated reactor trip

Figures 4-3 and 4-4 show the “safety-related” logic for reactor trip and parallel “non-safety” actions for Plant Protection. These figures illustrate differences in the Reactor Protection Logic for the three HTS configurations. Figure 4-3 shows the logic for Reactor Protection if the SG are placed in secondary loops. Figure 4-4 shows the logic for Reactor Protection if the SGs are placed in primary loops). These figures show “safety-related” logic paths — namely, “Control Rod Trip” or “Reactor Building Isolation” — as red pathways. Inputs on the left of the figure flow toward the right, to the box marked CONTROL ROD TRIP, or elsewhere on the figure. A reactor trip, and possible parallel actions (shown by the blue pathways), result from these inputs. Note that the red and blue colorings distinguish “safety-related” and “non-safety” actions.

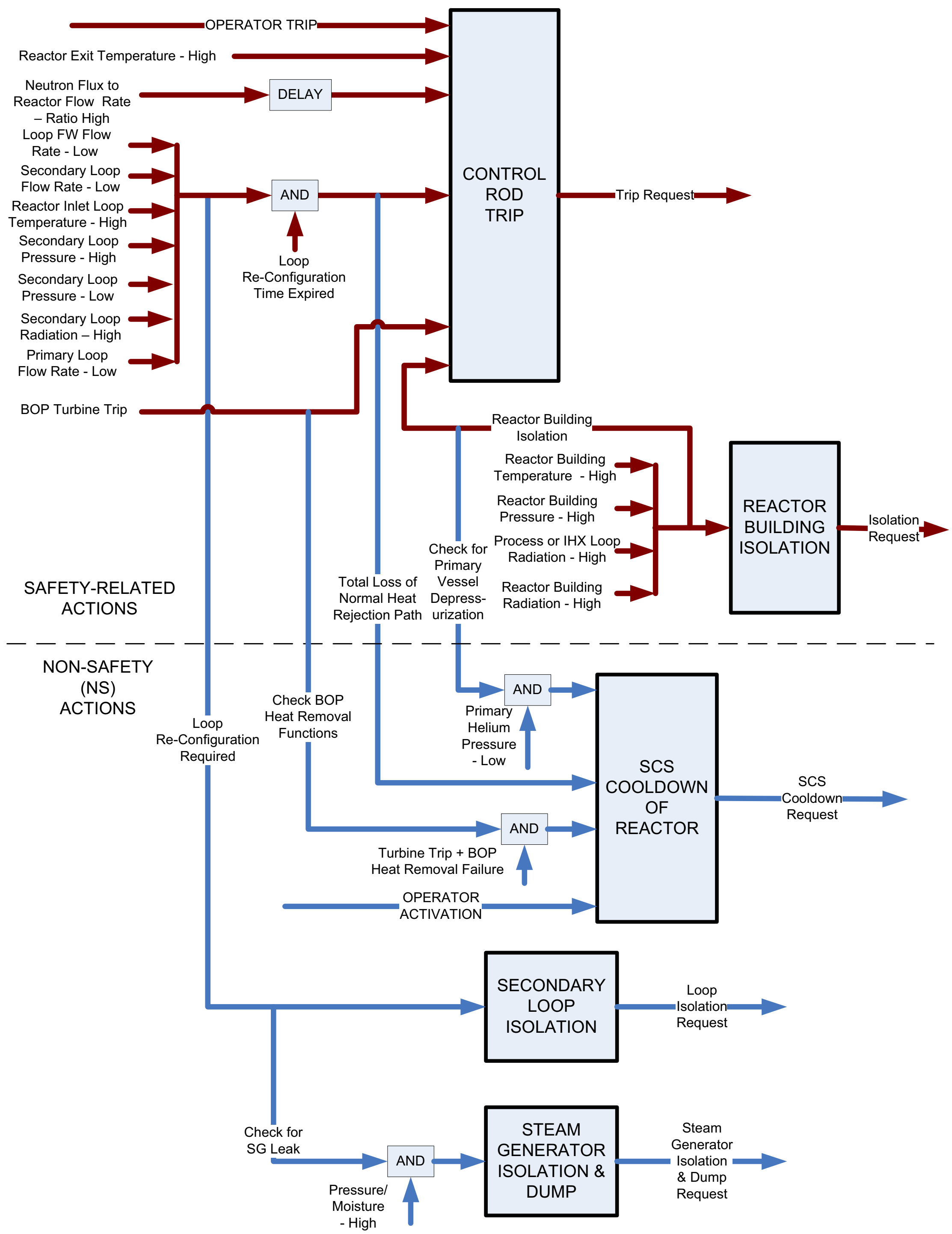


Figure 4-3. Protection Logic with Steam Generators in Secondary Loops

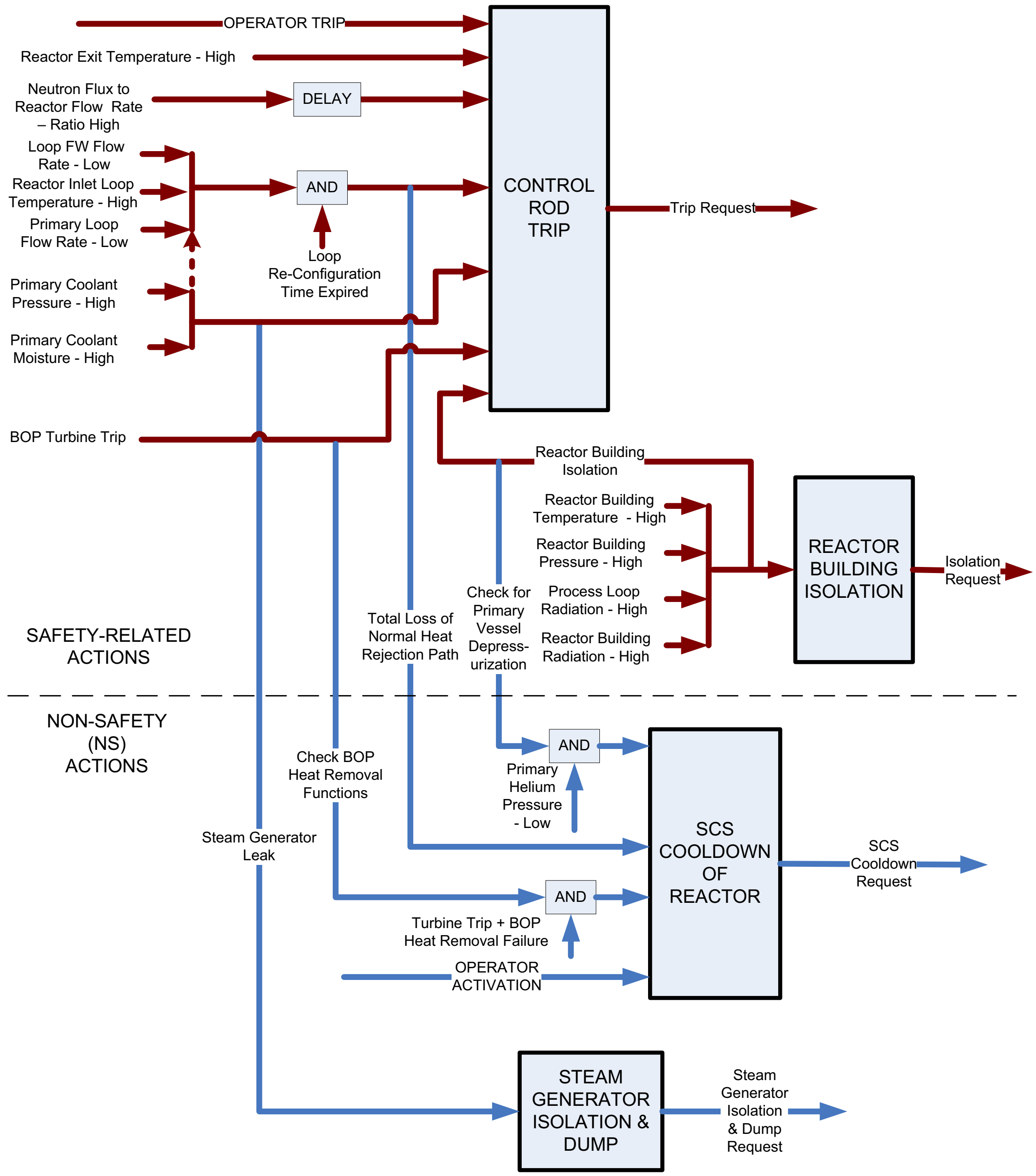


Figure 4-4. Protection Logic with Steam Generators in Primary Loops

Combined actions of the Protection Systems and the Plant Control, Data, and Instrumentation System (PCDIS) maintain normal cooling (instead of SCS cooling) whenever possible. This allows the most rapid cooling of the reactor (by comparison with SCS cooling) and assures protection of Steam Generators from thermal stress damage during reactor cooldown operations.

Differences between the protection logic shown in Figures 4-3 and 4-4 arise from the SGs being located in secondary or primary loops. These differences will affect the Protection System design, depending on which configuration is selected. Interpretation of the differences in transient response is continued below:

- Reactor Trip only — Events which flow directly into the box labeled CONTROL ROD TRIP on Figure 4-3 or 4-4 (for example an operator initiated trip or a slow, sustained control rod withdrawal [DBE 2 from Table 4-3]) require a reactor trip but do not require parallel SCS cooldown (SCS COOLDOWN OF REACTOR). Instead, the plant control system (the PCDIS) begins reactor cooldown with normal cooling functions[4]. DBE 1 is another event of this type. If the Protection System determines that this event has occurred (and not another, such as DBE 3) the reactor will be tripped without activating SCS cooling because this is the proper action for rapid sustained control rod withdrawal where all normal cooling functions remain intact. However, events which cause a reactor trip and impair normal cooling may need the SCS and other parallel actions, as explained below.
- Reactor Trip plus SCS — The SCS is activated in parallel with reactor trip if inputs to the Protection System indicate that normal cooling has been interrupted. An example of this type of event is DBE 5, which invokes SCS cooling in addition to turbine trip (a BOP function) and reactor trip because the final BOP cooling sources are also lost in this event. However, if a turbine trip were to occur because of DBE 4 (loss of offsite power) the SCS is not needed if the turbine bypass system heat-removal functions remain available.
- Reactor Trip plus Loop Isolation — With the SGs in secondary loops, DBE 9, 10, and 11 each require SECONDARY LOOP ISOLATION. This is included in the Protection Logic shown in Figure 4-3. If only one SG loop is operating during one of these events, the Protection System issues a reactor trip and starts SCS cooldown as well. (Because the BOP heat-removal functions cannot be used without a SG operating.) However, when one-out-of-two loop isolation occurs successfully during one of these events, normal control and "non-safety" protection actions allow a smooth transition to single-loop plant operation without a reactor trip. (Note the allowance for "Loop Re-Configuration Time" in Figure 4-3.) Protection Logic for DBE 9, 10, and 11 would not be required for a

[4] Normal cooling with the BOP functions is used because the "defense in depth" strategy requires use of the RCCS to be unlikely (multiple failures, etc). Therefore, it is desirable to retain normal cooling to cool the reactor following a reactor trip. The SCS is the next choice because it is designed to cool the reactor to lower temperatures quicker than the RCCS and thereby minimize interruption of normal operations. The defense-in-depth objective is maximized by using normal cooling first, then SCS cooling if normal cooling is unavailable.

configuration with "primary loop" SGs (Figure 4-4). However, these plants do require STEAM GENERATOR ISOLATION AND DUMP and parallel "safety-related" reactor trip as a precaution against core damage. STEAM GENERATOR ISOLATION AND DUMP is needed only as a "non-safety" action in regard to steam generator protection for plants with steam generators in secondary loops. It is expected that the SGI&D hardware will be significantly less rigorous if the SGs are in secondary loops.

- Reactor Trip plus SG Isolation and Dump — When the SGs are in primary loops, as mentioned above, DBE 7 requires STEAM GENERATOR ISOLATION AND DUMP and a reactor trip (see Figure 4-4). It should be noted that, in the event of primary-coolant steam ingress (well above operator alarm levels), reactor trip is required even though reactor cooldown may be managed by operator action using the remaining SG loop in cases of one-out-of-two loop failure. SCS COOLDOWN OF REACTOR would not activate unless the control systems failed to re-configure the plant for one loop operation or the BOP cooling function was impaired. In these cases, SCS cooldown would also be activated. It should be noted that a more detailed level of design will be required to enable the instrumentation/decision-making capability for loop by loop discrimination of events and subsequent Protection System action. This will also require more instrumentation than previous MHR steam plants. Detailed analysis will be needed, as well, to verify proper reactor damage prevention strategies in steam ingress events occurring at very high reactor temperatures.
- Reactor Building Isolation plus Reactor Trip — All events which activate the REACTOR BUILDING ISOLATION functions (DBE 7 and 8) because of Reactor Building temperature, pressure and radiation level monitors, also cause a reactor trip to occur. Although a major depressurization of the vessel system (DBE 7) and loss of primary coolant would require SCS cooldown, lesser events (DBE 8) would not need the SCS. Normal cooling is used for reactor cooldown in these events. The SCS logic contains a check to determine if primary cooling is impaired and the SCS should be called for. Similar logic to check the magnitude primary coolant activity escaping the Reactor Building via secondary pathways is included in the REACTOR BUILDING ISOLATION function.

Protection Actions for "Non-Safety" Events (Table 4-6) show DBE 13 through 17. These events may invoke Protection System end-actions through "safety-related" hardware such as Reactor Building Isolation Valves, but are handled by "non-safety" decision logic. The "non-safety" decision logic set-points are lower than "safety-related" setpoints, but would activate the same hardware function. In previous MHR design efforts, the Investment Protection System (IPS) refers to "non-safety" portions of the Protection System. Different nomenclature may eventually be used for NGNP. However, the "non-safety" functions will be designed using the same methods, requirements and redundancy (two-out-of-four logic) that are used in the "safety-related" Reactor Protection System (RPS). One of these functions would isolate the hydrogen plant processes to protect plant personnel and equipment in the event that secondary radiation exceeded predetermined values (DBE 13). It might also be the case that the REACTOR BUILDING ISOLATION FUNCTION would include the same or similar detection measurements to assure that all paths leading from the Reactor Building are protected by "safety-related" hardware. In this case, "safety-related" decision logic would activate "safety-related" hardware (elevating DBE 13 to the "safety-related" category, but using a different strategy, allowing radiation detection and closure of the isolation valves at higher secondary radiation levels). Secondary or process loop radiation pathway counts for each of the HTS configurations are: **(III) = 2; (II) = 6; (I) = 4**.

4.2.1.3 Protection System Actions and Steam Plant Configurations

Table 4-8 shows Protection System actions and provides more information about the effect of the HTS configurations on the Protection System design.

4.2.1.4 Plant Control, Data, and Instrumentation System [PCDIS]

Similar applications of the MHR and larger HTGR plants have been considered in the past. These have lead to a consistent set of requirements which apply, at a top level, to the three HTS configurations described in Section 3. Documentation has addressed power operation, startup, shutdown, and abnormal operation, and has included control algorithms, control software specifications, control architecture, and various results for an integrated control design effort. Top-level requirements from these efforts should also apply here and are listed below.

- Utilize a "single point" operation command center for all plant operations, with inclusion of a "Remote Shutdown" facility compatible with licensing and operational requirements
- Develop information design strategies which quickly identify abnormal events or impending events (warning and alarm information), and which support the ability to quickly restore and operate the reactor and secondary systems following an abnormal event.
- Provide real-time information data systems to support all plant operation, including various plant activities such as communication, surveillance, radiation monitoring, and BOP activities. Also provide clear actions-taken and status-of-plant histories
- Use digital computer technology for implementation of Control and Protection algorithms, measurement processing, issuance of commands to end-action hardware, and providing operator PCDIS and Protection Systems information
- Provide redundant hardware reliability features

Table 4-8. Protection System Action and Steam Plant Configurations

END-ACTION	PROTECTION FUNCTION NAME	PRIMARY HARDWARE IN SG PLANTS I, II OR III	END-ACTION METHOD	SYSTEM PERFORMING PROTECTION END-ACTION
1	Control Rod Trip	Reactor System **(All SG Plants the same)**	De-energize Control Rod Holding Coils (backup — Reserve Shutdown System)	Reactor Neutron Control System
2	Reactor Building Isolation	Reactor Building **(No secondary isolation in SG Plant III - 1 IHX to isolate. SG Plant I has 2 IHXs to isolate. SG Plant II has 3 IHXs to isolate.**	Close Reactor Building Isolation Valves and Loop Isolation Valves (if loop radiation detected above safety-related level)	Reactor Building Isolation System
3	Secondary Loop Isolation	Secondary IHX **(Needed only for Steam Plant I & II. See above.)**	Close Isolation Valves on a Per-Loop Basis	Loop Isolation System
4	Steam Generator Isolation and Dump System	Steam Generator Isolation Valves & Dump System **(Needed only for Steam Plant III. SG Plants I & II isolate SGs at Reactor Building. BOP performs SGI&D outside RB.)**	Close Isolation Valves on a Per-Loop Basis	Steam Generator Isolation and Dump System
5	SCS	Shutdown Cooling System **(All SG Plants the same)**	Shutdown Operating Circulators and Start SCS Control Sequence	SCS Control System
6	BOP Turbine Trip	Balance of Plant **(All SG Plants the same)**	Activate Turbine Stop Valves	Turbine Protection System
7	H_2 Process Isolation	Process IHX **(SG Plants II & III the same. SG Plant I isolates only Secondary IHXs. See action 2 above.)**	Shutdown Process circulators. Close Process IHX Isolation valves.	Process Helium Supply-Return System
8	HSS Charging Isolation	Helium Purification System **(All SG Plants the same)**	Close HSS Charge Line Isolation Valves	Helium Charging System
9	SCHE Isolation and Drain	SCHE Isolation System **(All SG Plants the same)**	Close SCHE Isolation Valves. Open SCHE Drain	Shutdown Cooling Heat Exchanger Isolation System

- Provide operation manuals and procedures to assist operators in planning and performing plant operations.

The PCDIS design effort consists of input from control designers, control vendors, Architect-Engineer design teams, etc. Control Room consoles (and “Control Architecture”), digital processors, electronics, control support facilities, plant and reactor control systems design specs for vendor and AE control procurement and installation efforts, instrumentation design, instrumentation lists (including data base requirements), Human-Machine Interface (HMI) assessments and requirements, Control Room layout Sketches, I & C design drawings and as-built drawings, etc. all come under the PCDIS design task. The PCDIS ultimately provides overall integration of the design processes. As in past programs, a Control Development Simulator (CDS) model will be developed and used to obtain Protection and Control System algorithm sets. The CDS is necessary to develop the control features of each Steam Plant (or the selected plant), provide real-time Human-Machine Interface (HMI) assessments, and provide a basis for full-scope NGNP Simulator recommendations.

Although the above efforts are significant, and will produce specific results for a specific plant selection, the overall scope is expected to be similar regardless of which HTS configuration is selected.

4.2.1.5 Control of MHR as Multi-Loop Steam and H2 Production Plant

A preliminary assessment of the control functions for the three HTS plant configurations has shown that past Steam Plant control design strategies are applicable to a dual-function Steam Plant. Earlier MHR and HTGR nuclear-steam plant design strategies, including Fort St. Vrain, the large HTGR plants and the NPR/MHR, all incorporate similar control philosophies which recognize reliance on the inert helium coolant, the strong negative temperature effect on reactivity, the large thermal capacity of the core and other features inherent in MHR.

Figures 4-5, 4-6, and 4-7 show the tentative control systems for each of the three HTS configurations. The control design should incorporate several of the design features from earlier GA Steam Plants as follows:

- REACTOR POWER CONTROL — Sequential control rod withdrawal/insertion using stepping motors and ex-core flux measurements for neutron flux control.

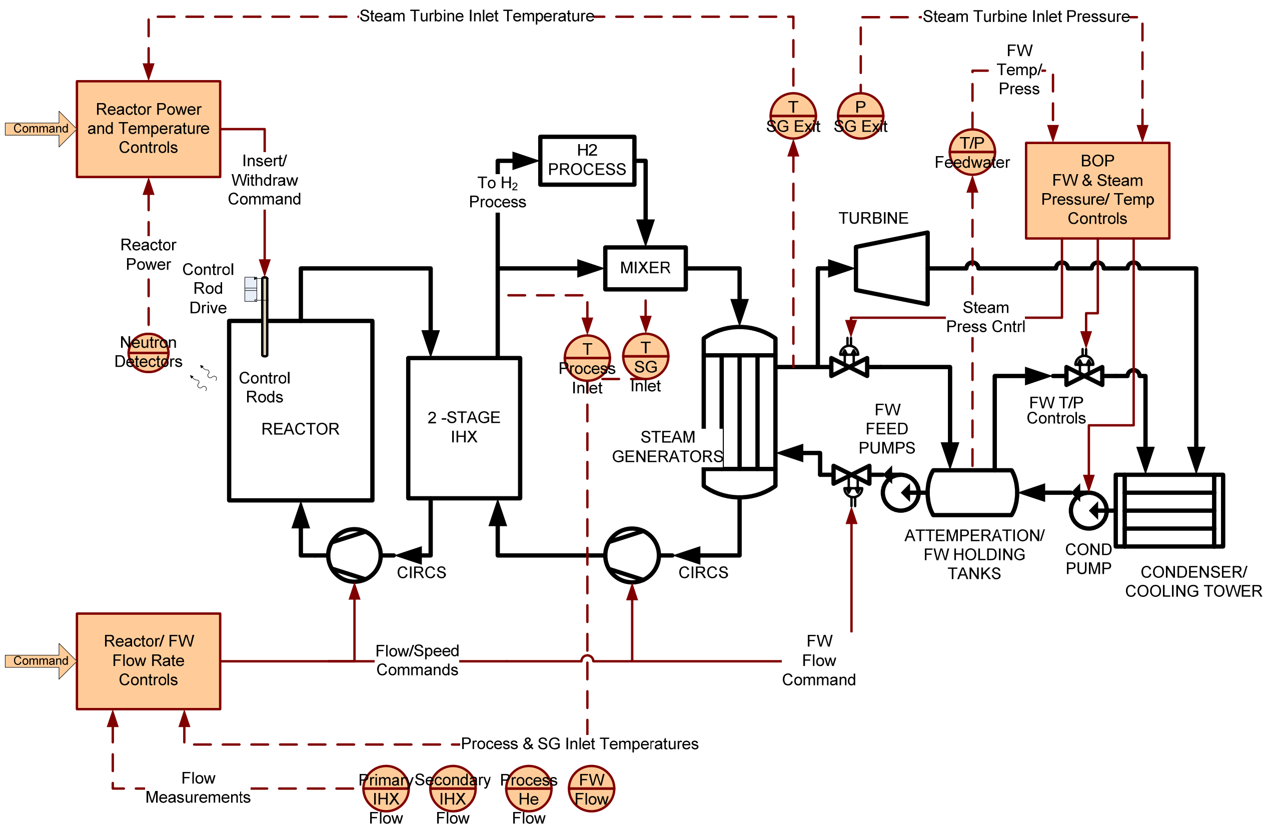


Figure 4-5. Plant Control System for Indirect Serial HTS Configuration with 2-Stage IHX, Configuration I

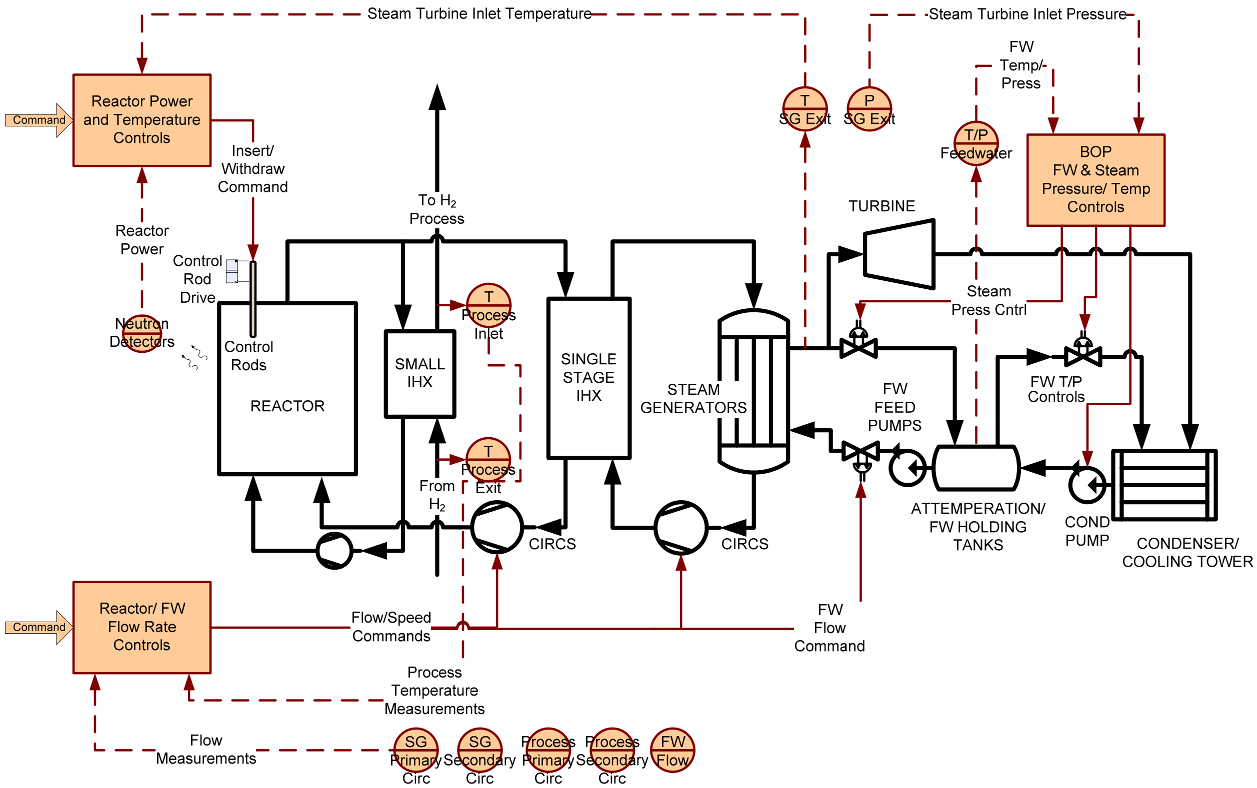


Figure 4-6. Plant Control System for Indirect Parallel Primary Loop HTS Configuration, Configuration II

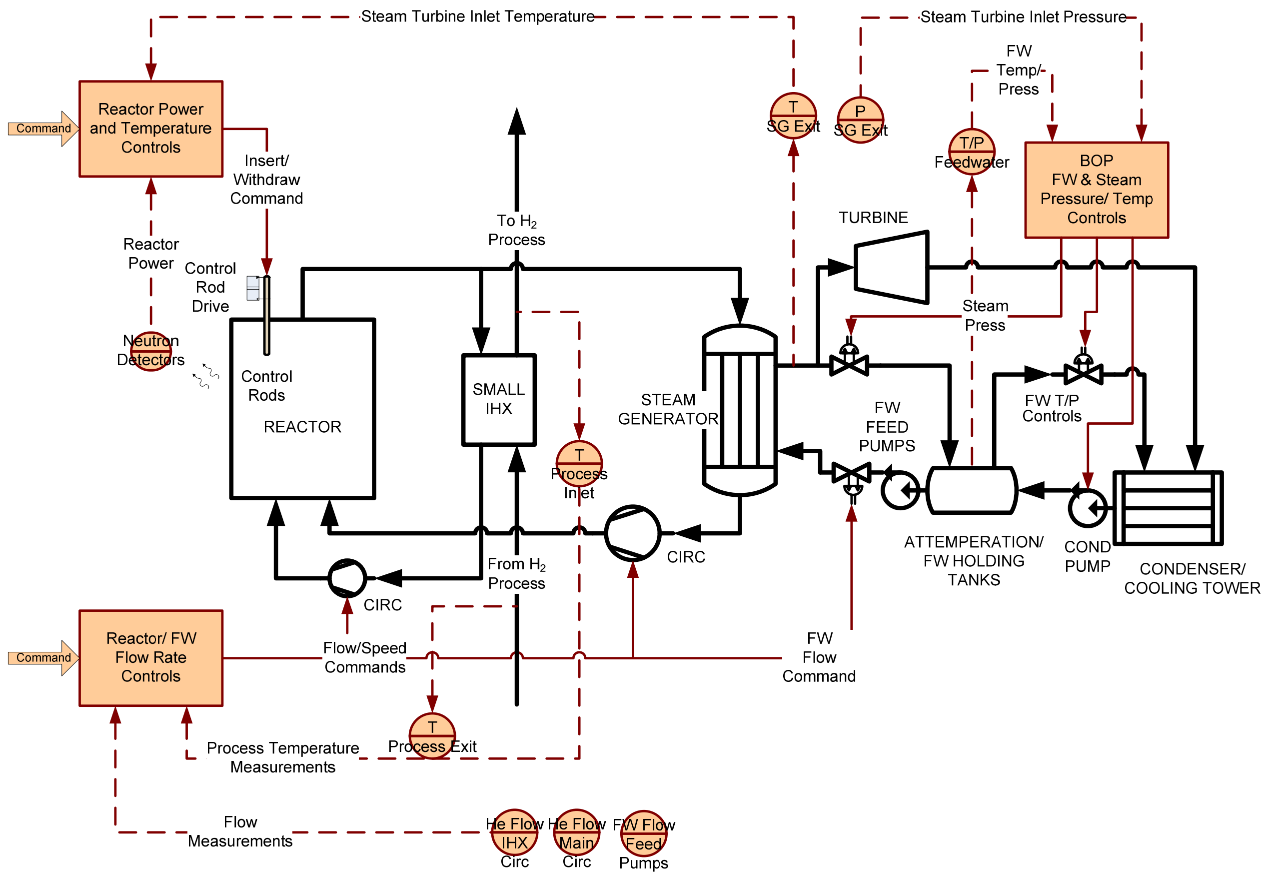


Figure 4-7. Plant Control System for Configuration with Primary Loop SG and H2-Loop IHX, Configuration III

- REACTOR, SECONDARY AND PROCESS HELIUM FLOW RATE CONTROL — Variable-frequency motor driven circulators and circulator implemented measurements to determine flow rates for adjustment of flow rates during reactor power change.

- STEAM GENERATOR TEMPERATURE CONTROL — SG exit temperature control, commanding reactor power setpoint, with reactor flow rate control tightening for good load-following and step response.

- BOP CONTROLS — Steam Turbine inlet pressure control and Steam Generator FW inlet pressure/temperature control provide end-to-end steady-state balance of reactor power and heat rejection processes.

- FEEDWATER FLOW RATE CONTROL — Variable-frequency motor driven feed pumps, flow control valves, with feed water flow measurement and control accessible to the Reactor Plant Control system to allow full command of the reactor power dissipation processes.

Table 4-9 shows expected production configurations for each of these plants.

Table 4-9. Dual Production Plant Operating Configurations

Production Mode	Reactor MW Electric	Reactor MW Hydrogen	Production Objective
Full Reactor Temperature. Both Electric and Hydrogen Production	535	65	Achieve maximum output capacity with hydrogen production and electric system operating at full capacity. Electric production is “base load” or very limited load following.
Lowered Reactor Temperature with Electric Production <u>Only</u>	535+	0	Achieve maximum electric output functionality. This mode is used to demonstrate electric production capability such as load following to below 50% output, step load change, etc.
Limited Electric/ Hydrogen Production	TBD	TBD	This mode used to achieve stable hydrogen production at lowered reactor power, and would allow single steam loop operation as a means of recovery from upset conditions.

The Hydrogen Production capability requires Reactor Plant control features to manage IHX heat balance, secondary helium flow rates, and reactor temperatures during transient operation. Table 4-10 illustrates the necessary control features implied by Figures 4-5, 4-6, and 4-7.

Table 4-10. Transient Effects Resulting from Controlled Parameters

Type of Change in Plant Operation	Direction of change from Steady State	Controlled Parameter Change/Effect
Change of electric output to lower value while Turbine Inlet steam temperature remains near steady state. Used in all modes, but is key to Electric Only mode.	↓ ↓ ↓ ↕ ↓	He primary flow [He_p] reduced in response to electric output reduction. He secondary flow [He_s] reduced in response to electric output reduction. FW flow [w_{FW}] reduced in response to electric output reduction. Turbine inlet steam temperature [T_{SG}] is held at or near steady state by automatic Steam Temperature Control action that adjusts reactor power to maintain T_{SG} at the required setpoint value [T_{SG} Control]. Reactor power is reduced by the T_{SG} Control, as T_{SG} is held at the setpoint value.
Begin elevation of reactor temperatures to begin hydrogen production. Might be combined with change below to begin hydrogen production when starting from lowered temperature, Electric Only mode.	↓ ↕ ↑	He_p reduced (slightly). w_{FW} remains fixed. The T_{SG} Control holds T_{SG} at the setpoint value, while Reactor and IHX temperatures adjust, but the reactor power returns to the steady state level. Helium temperatures at Reactor and IHX exit rise slightly (assuming no cool helium from process is being mixed in).
Adjust helium flow rates to deliver H_2 production heat to H_2 Process. Used in latter phase of plant startup to Full Electric/H_2 Production mode.	↑ ↕ ↕ ↑	Process flow, He_p and He_s are increased on a predetermined schedule at rates of 0.1 to 0.2 % per minute. Cooled helium is returned to the mixing point [T_M]. **[Configuration (I) only]** Steam Generator helium inlet temperature at the mixing point [T_M] remains near steady state, depending on process return and reactor temperatures. (Note: Additional cooling may be needed to maintain satisfactory temperature conditions for the process circulator in the early phase of this operation.) The T_{SG} Control holds T_{SG} at the setpoint value while Reactor and IHX exit temperatures rise. Reactor power is increased by the T_{SG} Control, which will automatically offset process power extraction while maintaining T_{SG} at the setpoint value.

Table 4-10 shows how the control can readjust temperature through control of reactor power and various flow rates. Several small scale effects — power change while holding temperature, temperature change while holding power, and redistribution of power between process and steam — are shown. These effects are mentioned in Table 4-10 separately. In actual operation — transition from one operating state to another — these effects would occur simultaneously. Additional feedback control systems, not explicitly shown in Figures 4-5, 4-6, and 4-7, adjust process temperature during scheduling of process and IHX/SG flow rates. It should be noted that considerable analytical design effort will be required to develop control system algorithms for these plants. Secondary and multiple loop configurations clearly add to the scope of this effort.

4.2.1.6 Plant Control Equipment Determined by Steam Plant Configurations

General control features of the control equipment and control architecture for the NGNP Electric/Hydrogen Production Plant were discussed in [PCDSR 2007]. These features will remain the same for each of the Steam Plant designs which are discussed above. Major considerations are listed again below:

- Separation of Control/Protection Functions — Separate information networks and control interfaces are needed for safety-related operator actions. Safety information provides the operators with warnings, alarms, equipment condition readouts, and progress of automatic Investment Protection System or PCDIS actions.

- Multi-Level Information Hierarchy — Figure 3.10-5 of [PSDSR 2007] shows levels-of-information features that would be provided in a modern nuclear plant. A top level "Plant Information Network" gathers information from lower levels, including plant instrumentation and control hardware interface levels, and makes this information available to the operators. Operational decisions by operators are based on all information throughout the information hierarchy — including information from outside the plant.

- Modern digital display interfaces — Operator display features in the NGNP plant will probably be of this type.

- "Command View" arrangement — All control associated buildings, consoles, displays, lighting, viewing areas, etc achieve supervisory overview, minimize Control Room staffing, optimize operations, minimize downtime, enhance maintenance activities, and create wide visibility for all reactor and plant operations. Previous HTGR programs, such as the CEGA Tritium Production Plant (NPR/MHR), supported this approach and offer specific design selections which may be utilized for NGNP.

Control System development for each specific Steam Plant configuration, although similar in scope, differ in the area of Plant Control design. Table 4-11 shows some expected Plant Control equipment similarities and differences between the Steam Plant configurations.

Table 4-11. Control System Action and Steam Plant Configurations

CONTROL ACTION	FUNCTION NAME	PRIMARY HARDWARE IN SG PLANTS I, II OR III	END-ACTION METHOD	SYSTEM PERFORMING CONTROL ACTION
1	Neutron Flux Control	Reactor System **(All SG Plants the same control algorithm)**	Measure Neutron Flux. Command through stepping motor withdrawal/ insertion of Control Rod Bank	Reactor Neutron Control System through PCDIS
2	Turbine Inlet/ Main Steam Temperature Control	BOP and Reactor System **(All SG Plants the same except different dynamics imposed by secondary, direct, split, combined etc variations may require a different FB control algorithm for each Plant.)**	Measure Main Steam Temperature and Primary Flow Rate. Command Neutron Flux through PCDIS FB Control Algorithm	Reactor Neutron Control System through PCDIS
3	Turbine Inlet Steam Pressure Control	BOP **(All SG Plants the same control algorithm)**	Steam Extraction/Heat Recovery, Throttling or TBD	BOP through PCDIS
4	Steam Generator Inlet Pressure Control	BOP **(All SG Plants the same control algorithm)**	Condensate Heat Recovery and Pressure/ Temp Control or TBD	BOP through PCDIS
5	Steam Generator Flow Rate Control	BOP **(All SG Plants the same except different feed forward command strategies imposed by secondary, direct, split, combined etc. More instrumentation in SG Plants I & II. All require different control algorithms)**	Variable-Frequency Pump Motor Speed Control and FB Algorithm to Flow Control Valves	BOP through PCDIS

Table 4-11 (Cont.) Control System Action and Steam Plant Configurations

6	Primary Flow Rate Control	Primary Circulator System **(All SG Plants the same except different feed forward command strategies imposed by secondary, direct, split, combined etc. More instrumentation in SG Plants II & III. Least in SG Plant I. All require different control algorithms, but III is least complex.)**	Variable-Frequency Circulator Motor Speed Control FF Command and Flow Measurement to FB Algorithm for Incremental Flow Adjustment	Primary Circulator System through PCDIS
7	Secondary Flow Rate Control	Secondary Circulator System **(<u>Not needed for SG Plant III</u>. SG Plants I and II similar except different feed forward command strategies because SG Plant II has Process IHX. More instrumentation needed in SG Plant II. Different control algorithms required for I & II.)**	Variable-Frequency Circulator Motor Speed Control FF Command and Flow Measurement to FB Algorithm for Incremental Flow Adjustment	Secondary Circulator System through PCDIS
8	Process Flow rate Control	Process Circulators **(All SG Plants the same except feed forward command requires different FF command algorithms.)**	Variable-Frequency Circulator Motor Speed Control FF Command and Incremental Flow Adjustment	Process Circulators through PCDIS
9	Process Temperature Control	Process, Primary and Secondary Circulator Systems **(All SG Plants use same technique of helium to helium (IHX) or helium to steam (SG) flow ratio adjustment on transition to full production level power with measurement and FB control of process temperature as a new feature in all SG plants. But each requires different FF and FB command algorithms. Issues of relative design complexity, precision of final reactor/process temperature adjustment, etc not determined.)**	Automatic FB Control Follow-up to FF Flow Command Subsequent to or Preceding Plant Transition Between Modes (e.g. Remains in Stand-By/Tracking Mode during <u>Electric Only</u> operation of plant)	All Circulator Systems through PCDIS

Table 4-11 shows "end-action" methods for the nine control functions listed in the table. Except for "Process Temperature Control" (CONTROL ACTION 9) the control functions are similar to Steam Plant control functions developed in previous MHR designs. However the following new MHR design considerations should be addressed in further control development efforts:

- Re-configuration of the Steam Plant from multiple to single-loop operation is needed following a single-loop upset event (see Section 4.2.1) or to support various hydrogen production options. The control design may draw from the Fort St. Vrain plant, which used multiple steam generator loops, but the objectives were different. Use of indirect IHX loops, management of the IHXs, and flexibility allowances in the production processes presents "plant re-configuration" design issues not addressed previously. For example, there is a 50% reduction in hydrogen plant output in re-configuring Configuration I from two loops to one because Configuration I does not include a dedicated process IHX. The single-loop upset re-configuration actions in this plant might affect the hydrogen process output differently than if the same event occurred in Configurations II or III.
- Reactor Trip can occur from a variety of operating conditions in the dual-function, multi-loop plants discussed here. Correct control system response to manage Reactor Trip and to protect against SG "overcooling" has to be developed for all reasonable scenarios.
- Helium circulator flow scheduling during transient operations will be more complex than in previous designs and will require more instrumentation for control. This is especially true for the two "indirect" configurations. Conversely, design of the SGI&D features with SGs in secondary loops may be much simpler.
- Process helium circulators may need temperature protection during some operations. Cooling facilities (part of the H_2 process, helium flow equipment) would then need additional control functions.
- Operational features, not determined in past designs, will be needed for these plants. It will be necessary to determine what portions of the plants will be needed, and at what minimum level the hydrogen plant can be operated when, for example, demonstration/testing of the H_2 process function is the only desired objective.
- Application of the control and protection system design for these plants has not been reviewed beyond a cursory level. This will probably require specific plant configurations to be developed. If for example the production ratio requirements were changed in Configuration I to allow a higher ratio of H_2 to electric output, the changes might be easier to make than in the other two configurations. On the other hand, if a gas-turbine plant was included in parallel with a single SG plant, control and other changes to accommodate the gas-turbine plant might involve more Hydrogen Plant interaction in the Configuration I design.

4.2.2 Plant Operation and Control Conclusions

Plant Control and Protection Systems can be developed for each of the three HTS Configurations. These can rely on earlier MHR and HTGR control/protection concepts with varying degrees of difficulty. Key concerns are secondary loops incorporated in the reactor heat removal processes, development of dual-production control features, and selecting the most beneficial operational and safety features from the many possible options.

At the current level of design detail, no clear selection of one HTS configuration can be derived from projection of the necessary control and protection design efforts. The same overall design scope is expected for any of the configurations. At one level of comparison — differences between the indirect plants and the plant with primary coolant fed to the steam generators — some differences are noted in the area of Protection System and Control System design. Configuration III requires a more rigorous strategy to protect the reactor and vessel system because of potential steam ingress directly into the primary coolant. This may also require more expensive facilities for Steam Generator Isolation and Dump. On the other hand, Configuration III requires the least “safety-related” instrumentation and contains the fewest IHX-failure-related “radiation pathways” for primary coolant leakage from the Reactor Building (through secondary piping penetrations). For similar reasons, control algorithm design might be somewhat easier for Configuration III as well. Also, new safety concerns such as rapid depressurization of the secondary systems (DBE 10) have to be addressed.

Adaptability to NGNP requirement changes, such as changing the desired ratio of process hydrogen output to plant electric output, might favor Configuration I. It is not certain that operating a gas-turbine power conversion plant with a single steam generator plant and the hydrogen plant would also favor this design. However, none of the operational aspects of such a change are meaningful unless more specific plant features are available. It is recommended that modification of the NGNP requirements should also include an update of plant operation and control features.

4.3 Safety, Reliability, and Maintainability

4.3.1 Safety

Certain safety implications arise by locating the steam generator within the primary coolant system. With the steam generator in the primary system, there is the possibility of direct communication between the water in the steam generator and the primary helium coolant. Since the water pressure in the steam generator tubes is designed to be greater than that of the primary coolant, any tube leaks will allow moisture to enter the helium and chemically interact with the reactor core graphite. The core will suffer corrosion as a result of CO, CO_2, and CH_4 production.

Locating the steam generator in the primary loop requires that the steam and feedwater systems be equipped with a steam-water dump system that, in the event of a water leak into the primary coolant, can be used to rapidly empty the steam generator of its water content. In addition, isolation valves need to be provided on both the steam generator feedwater and steam piping for isolating the steam generator. To minimize the potential for leakage of water from the steam generator into the primary coolant, the steam generator must be designed, fabricated and operated into accordance with the applicable requirements for Class I components of the ASME B&PV Code.

Whether the steam generator is located in the primary or secondary loop, the need for maintenance of the feedwater quality is also important. A full-flow demineralization system is required for the feed system, and attention to water quality must be an ongoing process.

Insights into the potential consequences of water leakage from steam generators into the primary system can be obtained from the safety analysis results contained in [PSID 1992] for the MHTGR plant defined in [CDSR 1987]. [PSID 1992] contains safety analysis results for the following moisture ingress design basis events:

- A steam generator tube leak equivalent to the rupture of a single steam generator tube, Design Basis Event (DBE) No 6.
- A moderate steam generator tube leak, the same as in DBE No. 6, but without forced cooling, DBE No. 7.
- A small steam generator moisture leak with failure of the moisture monitors, DBE No. 8.
- A small steam generator leak with failure of a steam generator dump valve to recluse, DBE No. 9.

There are two key safety related consequences of moisture ingress, oxidation of core graphite and the release of fission products. Summaries of the [PSID 1992] analysis results with respect to these key safety related issues for each of the above moisture ingress events are provided below.

Moisture inleakage – DBE No 6 [PSID 1992, Section 15.7]

DBE No. 6 is a steam generator tube leak equivalent to the rupture of a single steam generator tube. The event sequence is:

- Moderate steam generator tube leak occurs [5.7 kg/sec/12.5 lbm/sec)]

- Moisture monitors detect the leak
- Reactor is tripped using outer control rods
- Main cooling loop is shutdown
- Steam generator is isolated at feedwater and steam headers
- Steam generator inventory is emtied successfully to dump tanks and dump valves recluse
- Shutdown Cooling System (SCS) is started successfully, thus restoring forced circulation cooling
- The reactor vessel remains pressurized, primary coolant boundary integrity is maintained, and no radionuclide release occurs

The moisture ingress results in localized oxidation of the bulk moderator core graphite. The most oxidation occurs in the core bottom reflector blocks because their surface area to volume ratio is greater than for the core support blocks and posts and because they are hotter than the core support blocks and posts. The average fractional burnoff throughout the entire mass of core bottom reflector blocks for this event is about 2×10^{-4} weight fraction and the maximum local (hot channel) fractional burnoff is 9×10^{-4}. The core support blocks and posts incur less burnoff that occurs mainly on their surfaces. These fractions are sufficiently small that, when coupled with the factor of 3 to 4 safety margin on the core support components, no loss of core support capability occurs during this event.

Steam inleakage results in fission-product release to the primary coolant by three mechanisms: (1) hydrolysis of UCO particles having failed coatings, (2) liberation of sorbed fission products in the bulk moderator graphite which is oxidized, and (3) steam-induced vaporization and recirculation of fission products plated out on metallic surfaces. The noble gas release to the primary coolant is calculated to be on the order of 60 Ci. The iodine release is about 108 Ci. The release of metallic fission products from the oxidized bulk moderator graphite is estimated to be about 1 Ci; the release of metallics from steam-induced recirculation is 43 Ci. No venting of the fission products occurs from the pressure vessel and they are fully contained with the primary system. Therefore, no offsite dose results. Eventually, the re-entrained fission products plate out once again on the surfaces of the primary circuit. Other radionuclides are removed by the Helium Purification System (HPS) and by natural radioactive decay.

Moisture Inleakage Without SCS Cooling - DBE No. 7, [PSID 1992, Section 15.8]

DBE No. 7 is a moderate steam generator tube leak the same as in DBE No. 6 but without forced cooling. The event sequence proceeds the same as for DBE No. 6 up to starting the SCS but SCS does not start on demand. DBE No. 7 then proceeds as follows:

- Core heat removal is by convection, conduction, and radiation to the Reactor Cavity Cooling System (RCCS)
- Pressure relief valve opens once to release a fraction of the primary coolant, resulting in offsite dose

The moisture ingress results in oxidation of the bulk moderator core graphite. The most oxidation occurs in the central part of the core and is relatively uniform with respect to core radius. There is no significant localized oxidation damage even in the hottest coolant channels. Only about 28% of the total water leakage is calculated to be available to react with the core because of the lack of circulation between the steam generator vessel and the reactor vessel. The average fractional burnoff throughout the entire mass of active core fuel elements is about 5.2×10^{-4} weight fraction. The average fractional burnoff throughout the entire mass of core bottom reflector blocks for this event is about 4×10^{-4} weight fraction and the maximum local (hot channel) fractional burnoff is 8×10^{-4}. The core support blocks and posts incur less burnoff that occurs mainly on their surfaces. These fractions are sufficiently small that, when coupled with the factor of 3 to 4 safety margin on the core support components, no loss of core support capability occurs during this event.

Fission products are released to the primary coolant by four mechanisms: (1) hydrolysis of UCO particles having failed coatings, (2) liberation of sorbed fission products in the bulk moderator graphite which is oxidized, (3) diffusion (due to elevated temperatures) of fission products out of fuel particles that have failed and (4) steam-induced vaporization and recirculation of fission products plated out on metallic surfaces. The noble gas release to the primary coolant is calculated to be on the order of 300 Ci. The iodine release is about 440 Ci. The release of metallic fission products from the oxidized bulk moderator graphite is estimated to be about 1.7 Ci; the release of metallics from newly failed fuel and from steam-induced recirculation is about 140 Ci.

Nominally, no venting of the fission products occurs from the pressure vessels and they are fully contained with the primary system. However, the relief valve may open once and reseat. If that occurs, less than 15% of the circulating gases and particulates will be released from the vessels. The resultant dose consequences meet the dose limits of 10CFR100 by a factor of margin of about 8500 or more.

<u>Moisture Inleakage with Moisture Monitor Failure - DBE No. 8, [PSID 1992, Sec 15.9]</u>

DBE No. 8 is a small steam generator moisture leak with failure of the moisture monitors. The event sequence analyzed is:

- Moisture inleakage at 0.05 kg/s (0.1 lbm/sec) in the steam generator

- Moisture monitors fail to detect high moisture level
- Control rods compensate to hold power at initial full power level
- Reactor trips automatically on high pressure
- Main loop trips automatically on high pressure. Steam generator isolation valves function properly
- Within 20 minutes, steam generator is dumped manually. The integrated leakage totals 841 kg (1850 lbm)
- Shutdown Cooling System (SCS) starts on demand
- The reactor vessel remains pressurized, primary coolant boundary integrity is maintained, and no radionulide release occurs

The moisture ingress results in oxidation of the bulk moderator core graphite. The most oxidation occurs in the hotter bottom half of the more recently fueled higher power regions of the core. There is no significant localized oxidation damage even in the hottest coolant channels. The average fractional burnoff throughout the entire mass of active core fuel elements is about 1.3×10^{-3} weight fraction. The average fractional burnoff throughout the entire mass of core bottom reflector blocks for this event is about 1.6×10^{-3} weight fraction and the maximum local (hot channel) fractional burnoff is 6.1×10^{-3}. The core support blocks and posts incur less burnoff that occurs mainly on their surfaces. These fractions are sufficiently small that, when coupled with the factor of 3 to 4 safety margin on the core support components, no loss of core support capability occurs during this event.

Steam inleakage results in fission-product release to the primary coolant by three mechanisms: (1) hydrolysis of UCO particles having failed coatings, (2) liberation of sorbed fission products in the bulk moderator graphite which is oxidized, and (3) steam-induced vaporization and recirculation of fission products plated out on metallic surfaces. The noble gas release to the primary coolant is calculated to be on the order of 116 Ci. The iodine release is about 254 Ci. The release of metallic fission products from the oxidized bulk moderator graphite is estimated to be about 13 Ci; the release of metallics from steam-induced recirculation is 113 Ci. The nominal circulating noble gas activity is about 23 Ci. No venting of the fission products occurs from the pressure vessel and they are fully contained with the primary system. Therefore, no offsite dose results.

Moisture Inleakage with SG Dump Failure - DBE No. 9, [PSID 1992, Sec 15.10]

DBE No. 9 is a small steam generator leak with failure of a steam generator dump valve to recluse. The event sequence analyzed is:

- Moisture inleakage at 0.05 kg/s (0.1 lbm/sec) in the steam generator

- Control rods compensate for reactivity effect of moisture and hold power at initial full power level
- Moisture monitors detect the leak
- Reactor trips on outer control rods
- Plant Protection and Instrumentation System (PPIS) trips the main cooling loop
- Steam Generator Isolation System functions properly
- Steam generator inventory is dumped. The integrated inleakage totals 18.1 kg (3.9 lbm)
- Dump System valves fail to recluse and the dump tank reaches the primary coolant pressure.
- Shutdown Cooling System (SCS) provides core cooling.
- The reactor vessel remains pressurized, primary coolant boundary integrity is maintained, and no radionuclide release occurs

The moisture ingress results in oxidation of the bulk moderator core graphite. The most oxidation occurs in the hotter bottom half of the core. There is no significant localized oxidation damage even in the hottest coolant channels. The average fractional burnoff throughout the entire mass of active core fuel elements is about 4.7×10^{-5} weight fraction. The average fractional burnoff throughout the entire mass of core bottom reflector blocks for this event is about 8×10^{-5} weight fraction and the maximum local (hot channel) fractional burnoff is 3×10^{-4}. The core support blocks and posts incur less burnoff that occurs mainly on their surfaces. These fractions are sufficiently small that, when coupled with the factor of 3 to 4 safety margin on the core support components, no loss of core support capability occurs during this event.

Steam inleakage results in fission-product release to the primary coolant by three mechanisms: (1) hydrolysis of UCO particles having failed coatings, (2) liberation of sorbed fission products in the bulk moderator graphite which is oxidized, and (3) steam-induced vaporization and recirculation of fission products plated out on metallic surfaces. The noble gas release to the primary coolant is calculated to be on the order of 124 Ci. The iodine release is about 83 Ci. The release of metallic fission products from the oxidized bulk moderator graphite is estimated to be about 0.3 Ci; the release of metallics from steam-induced recirculation is 137 Ci. The nominal circulating noble gas activity is about 23 Ci. The steam generator dump tank sustains the primary coolant pressure resulting from failure of the Dump System valves to recluse, and no offsite dose occurs.

The conclusions that can be reached based on the above MHTGR safety analysis results with regard to the safety implications of an NGNP HTS configuration with steam generation in the primary system are as follows:

- Moisture ingress into the primary coolant system from steam generator leakage is not expected to result in unacceptable average or localized oxidation of either the bulk core moderator graphite or the graphite core support components
- Moisture ingress into the primary coolant system from steam generator leakage is not expected to result in radionuclide releases in excess of regulatory limits

Placement of the steam generator in a secondary loop should eliminate issues associated with moisture ingress into the core from the steam generator. However, an intermediate heat exchanger (IHX) would be required to be installed between the reactor and the steam generator. Since the secondary coolant system (helium, CO_2 or other) should operate at a slightly higher pressure than the primary system, a leak in the IHX would allow secondary system coolant to enter the primary coolant, which should be of considerably less concern as regards damage to the graphite core. Such a heat exchanger will require use of very high temperature materials.

There is the possibility of developing a major pressure difference between the primary and secondary sections of an IHX. Either the IHX must be designed to accommodate a number of time-at-temperature pressure differentials for the IHX design lifetime or, the secondary system contain isolation valves near to the IHX that could be closed quickly to allow equilibration of the IHX internal pressures. There is uncertainty that an IHX can be designed with a reasonable lifetime taking into account the creep fatigue damage caused by occasional high pressure differentials at temperature. Likewise, there is uncertainty that suitable isolation valves can be developed because none currently exist. Isolation valves will also be required to create a boundary between the primary and secondary systems to avoid the need to design the secondary system to function as a Class I pressure boundary.

In all cases, in-service inspection (ISI) of the primary pressure boundary is an important safety issue and must be considered in the design of the steam generator and/or IHX pressure boundary. Procedures using remote equipment must be developed and the means to use such procedures and equipment must be considered in both the design of the steam generator and IHX.

4.3.2 Maintainability and Reliability

Maintenance of steam generators is expected to include finding and eliminating tube leaks. The steam generator design should include excess heat transfer surface area (5 to 10%) to accommodate loss of performance due to plugging leaking tubes. Further, the design of the inlet and outlet configurations of the tubes must allow for access to both ends of each tube, with enough physical space to perform the operations associated with tube leak checking and plugging. The plant design must consider the potential radiation fields that could exist in the areas where steam generator maintenance activity is expected. Proper design installation should attempt to assure the existence of very low radiation fields in these areas. Any tube plugging operation must be capable of being performed in a minimum amount of time consistent with high work quality.

While it is unlikely that a steam generator will have to be removed, such an eventuality should be considered in the design of the steam generator installation and in the design of the reactor building. The reactor building and overall plant arrangement should take into consideration access for cranes with sufficient lifting capacity for steam generator replacement. A similar situation exists with respect to the intermediate heat exchanger. Again, access and lifting capacity should be considered.

As in the case of steam generators, some provisions need to be made for resolving leaks in IHXs for the NGNP. A desirable solution would be one analogous to steam generator tube plugging where excess heat transfer area is provided to allow for some leaking surfaces to be isolated. For tube-and-shell IHXs, the approach could be the same as for steam generators. The situation is, however, quite uncertain for IHX designs based on compact concepts. In the absence of a specific compact IHX design, the possibility for IHX heat transfer surface isolation is not known. Currently, the only known solution for compact IHXs is heat transfer surface replacement, either as complete heat exchanger replacement for replacement of heat exchanger sections. Replacement of either complete IHXs or failed sections is envisioned to be considerably more involved than plugging tubes. As a result, compact IHXs present a much more complicated maintenance situation for resolution of leakages.

The IHX maintenance issues, coupled with the creep-fatigue design issues, indicate high uncertainties for NGNP IHX designs based on compact heat exchanger concepts. High uncertainty translates to high risk and, for the NGNP, the risk seems large for the steam-electric co-generation application. The risk might be acceptable for the hydrogen production process heat demonstration application that uses about 1/10 the heat of the steam-electric co-generation application. This much smaller size should translate into simpler and easier replacement of either failed heat exchanger sections or the complete heat exchanger. Plant design provisions should be more readily incorporated to enable IHX replacement with advanced or improved designs if required to obtain acceptable performance.

The uncertainties associated with the use of tube-and-shell IHX designs are perceived to be less than those of compact IHXs. Tube-and-shell IHXs are, however, considerably larger and, even though they are amendable to tube plugging, are more prone to requiring replacement than steam generators due to higher tube operating temperatures. They would be subject to the same differential pressure creep-fatigue damage mechanisms as compact IHX designs. The tube-and-shell large size, including impact on building size, translates into high capital cost and replacement, if required, translates into high maintenance costs. Cumulatively, these two effects further enforce the conclusion reached in Section 3 that an IHX in a primary coolant system coupled with steam generation in a secondary system would not be economic for commercial application.

4.4 Tritium Transport to NGNP End Products

A design issue of special interest for the NGNP is tritium control. Tritium will be produced in an HTGR by various nuclear reactions. Given its high mobility, especially at high temperatures, some tritium will permeate through the intermediate heat exchanger, steam generator, and hydrogen process vessels, contaminating the product hydrogen and process steam. This tritium contamination will contribute to public and occupational radiation exposures; consequently, stringent limits on tritium contamination in the product hydrogen are anticipated to be imposed by regulatory authorities.

Design options are available to control tritium in an HTGR, but they can be expensive so an optimal combination of mitigating features must be implemented in the design. Tritium control will be manageable regardless of whether the steam generator is located within the primary- or secondary coolant circuit of the NGNP, but it will be relatively easier if the steam generator is located in the secondary circuit because that configuration allows for the inclusion of a second helium purification system (HPS) in the secondary coolant circuit. However, overall plant economics will likely favor locating the steam generator in the primary circuit.

The following sources of tritium production have been identified, primarily from early surveillance programs at operating HTGRs (steam-cycle plants), and they can be reasonably well quantified for the NGNP: (1) ternary fission, (2) neutron activation of He-3 in the primary He coolant, (3) neutron activation of lithium impurities in fuel-compact matrix and core graphite, and (4) neutron capture reactions in boron used in control materials. Ternary fission will be the dominant source of tritium production, but this tritium will be largely retained in the TRISO-coated fuel particles. He-3 activation will generate a relatively modest fraction of the total tritium produced in the reactor; however, since it is born in the primary coolant, it will likely be an important source of tritium in the primary helium and, hence, of product contamination as well.

Tritium strongly chemisorbs on irradiated nuclear graphite at elevated temperatures. Consequently, a large fraction of the tritium entering the primary helium will be absorbed on the huge mass of graphite in the core. In operating HTGRs, the core graphite was observed to be a far more important sink for tritium removal than the HPS. However, a large fraction of this stored tritium can be released if water is introduced into the primary coolant.

As part of the Contamination Control Study [Hanson 2008], plant mass balances for tritium (H-3) were calculated with the TRITGO code for three different notional NGNP plant configurations: (1) a single two-stage IHX supplying a small hydrogen production plant and a SG in the secondary circuit, (2) a small IHX supplying a hydrogen plant and a large IHX coupled to a SG in the secondary heat transport system, and (3) a small IHX supplying a hydrogen production plant and a large SG in the primary heat transport system. While the uncertainties in these predictions are large, the results indicate that significant tritium permeation through the heat exchangers should be expected for all three configurations.

The prediction that tritium contamination will be a design issue for the NGNP is supported by the observed tritium behavior in operating HTGRs. Tritium has been monitored in all operating HTGRs to characterize its transport behavior and to demonstrate compliance with regulatory requirements for occupational exposures and environmental discharges [e.g., Hanson 2006]. The most prototypical H-3 data for a prismatic-core NGNP are expected to be from those the Japanese HTTR which has a prismatic core, an IHX, and has operated with a reactor outlet temperature of up 950 ^{o}C. While it is known H-3 transport has been investigated in HTTR, the results have not been published at this writing. The second most relevant H-3 surveillance data should be that from the Fort St. Vrain (FSV) HTGR.

Based upon the surveillance data from FSV and other steam-cycle HTGRs (Dragon, Peach Bottom 1, AVR and THTR), tritium will contaminate the process steam to some degree regardless of the location of the steam generator in the NGNP. However, it is noteworthy that for these earlier steam-cycle plants, all of which had their steam generators located in the primary circuit, tritium contamination control was not a significant operational or compliance issue. The environmental radioactive discharges from FSV were much less than the average US LWR with the exception of H-3 releases which were comparable to PWR releases on a Curie basis and actually higher on a Ci/GW(e)-yr basis. While the FSV H-3 releases to the environment were well below regulatory limits and presented no operational difficulties, tritium was nevertheless the dominant off-site dose contributor during plant operation. Compliance with environmental release regulations was also not an issue for the other operating HTGRs, but typically tritium was again the dominant off-site dose contributor.

Without engineered mitigating design features, the relative amount of tritium permeation through the heat exchangers of the NGNP will likely be higher than through the steam generators of previous operating HTGRs. First, more tritium will be released into the primary coolant of the NGNP because of the higher core temperatures in the NGNP compared to the earlier steam-cycle plants (the exception may be the AVR which operated with a core outlet temperature of 950 ^{o}C for a significant period of time). Secondly, the metal temperatures in the heat exchangers of the NGNP will be significantly higher than the metal temperatures in the steam generators of the previous steam-cycle plants (including AVR which had a cocurent superheater), and the permeation rate is exponentially temperature dependent.

Once programmatic limits on the allowable tritium contamination levels in the product hydrogen are adopted and a comparison has been made with the expected H-3 contamination levels in a specific NGNP plant design, trade studies can be conducted to determine which design option for H-3 control, or combinations thereof, is optimal for that plant design. At this point, the addition of a large helium purification system to the secondary coolant loop for tritium removal appears to be essential for the hydrogen plant loop. Also, the allowable Li impurity in core graphite should be reduced to the extent practical, and the B_4C granules in the lumped burnable poison and in the control rods should be coated to improve tritium retention (and resistance to hydrolysis). Tritium permeation barrier coatings, especially Al-based coatings, have the potential to dramatically reduce product contamination levels if a practical means can be identified for applying them to a printed-circuit type IHX.

For the steam production circuit, tritium control will be manageable regardless of whether the steam generator is located within the primary- or secondary coolant circuit of the NGNP, but it will be relatively easier if the steam generator is located in the secondary circuit because that configuration allows for the inclusion of a second purification system in the secondary coolant circuit.

With the steam generator in the primary circuit, the size of the HPS can be increased, but the dominant tritium sink in the primary circuit is expected to be the core graphite. Consequently, rather large increases in the HPS would be required to significantly reduce the amount of permeation into the secondary steam.

The cost of a large primary circuit HPS can be mitigated by taking the design approach used for the NP-MHR. Because of its tritium production mission, the predicted tritium release rates into primary He were quite significant; consequently, the NP-MHR had a large primary circuit HPS. However, only the front-end unit operations required for tritium (and hydrogen) removal, including copper-oxide oxidizer beds and molecular sieve driers, were scaled up compared to earlier commercial steam-cycle plant designs. After being processed through the front end of the HPS, half of the flow was returned to the primary circuit, and the remaining half was further processed through the LN_2-cooled charcoal beds for removal of the noble gases and residual chemical impurities.

While locating the steam generator in the secondary circuit would facilitate tritium control, the cost penalty for the inclusion of an extra loop with a large IHX and another large circulator is judged to be excessive. Consequently, it is expected that any steam generator will be located in the primary circuit of the NGNP and that tritium control will prove manageable for that configuration as it did for all previous operating steam-cycle HTGRs.

4.5 Degree to Which NGNP is Prototypic of a Commercial Plant

In preparing [PCDSR 2007], GA developed criteria for selection of the NGNP reactor power level from the NGNP mission requirements as defined in the Energy Policy Act of 2005 and the INL NGNP Preliminary Project Management Plan, and from NGNP mission recommendations provided by GA's utility advisors. The key selection criteria were determined to be:

1. Demonstration of reactor power capacity (product of power level and capacity factor).
2. Provide basis for the commercial VHTR plant engineering, procurement and construction (EPC) cost.
3. Provide basis for the commercial VHTR plant EPC schedule.
4. Support NGNP deployment in 2016 – 2018 time frame.
5. Provide basis for Design Certification of the commercial VHTR plant by the Nuclear Regulatory Commission.
6. Provide basis for operation and maintenance costs of the commercial VHTR plant.
7. Provide basis for fuel costs for the commercial VHTR plant

In applying these criteria to selection of the recommended power level for NGNP, a full-size 550/600 MWt reactor was judged to best satisfy the evaluation criteria. The conclusion was reached that the NGNP needed to be full-sized such that construction, licensing, and operation of the NGNP would eliminate much of the uncertainty associated with utility/user costs to build, license, and operate a commercial VHTR. The elimination of such uncertainty was judged to be essential to demonstrate to potential utility/users that a VHTR would not only be economically competitive with, but also enjoy a cost advantage over alternate means of electricity and/or process heat generation (without which there would be no incentive for a utility/user to build a VHTR).

The above evaluation criteria are considered to be equally applicable to selection of the preferred NGNP HTS configuration. These criteria lead to selection of full-sized systems that are fully prototypic of a commercial plant. Additionally, to be deployable as a commercial plant, the plant must not only be economically competitive with, but also have a cost advantage over alternative plants. In view of the economic evaluations contained in Section 3 and the operational and maintenance uncertainties identified in Section 4.3, none of the HTS configurations with an IHX in the primary coolant system coupled to a SG in a secondary system are expected to be economically competitive for a steam-electric co-generation plant. On the other hand, a VHTR plant having a SG in the primary system should be competitive and should meet satisfy requirements. A plant design for NGNP using this HTS configuration is recommended for further design development and for better definition of estimated costs and safety performance.

5. CONCLUSIONS AND RECOMMENDATIONS

Pre-conceptual design studies for the NGNP have resulted in the recommendation that the NGNP should produce steam for process heat or for generation of electricity using the Rankine cycle. The NGNP would then become a steam-electric co-generation plant for demonstrating commercialization of Very High Temperature Reactor (VHTR) technology to satisfy the mission requirements of the Energy Policy Act of 2005.

There are a variety of HTS configurations for the production of steam using nuclear heat from the NGNP. One approach is to use an IHX in a NGNP primary coolant loop for transferring reactor heat to a secondary loop containing a SG. Another approach is to locate a SG in the primary cooling system.

Three HTS configuration options for NGNP were identified for steam generation, one with a SG in the primary system and two HTS configurations with a SG in a secondary loop. Comparative evaluations were performed of the three HTS configurations. The evaluations addressed the relative economics, control and protection requirements, safety, maintainability and suitability of being prototypic of a commercial plant. The resultant recommendations and conclusions from these evaluations are as follows:

5.1 Economics

Conclusions from ROM comparative capital and O&M cost evaluations are as follows::

- For a NGNP plant with a single main primary loop containing a SG, the ROM plant capital component of steam production cost would increase by about 11% if the plant capacity was reduced from 600 MWt to 450 MWt.
- The ROM effect of the capital cost component on steam product cost of using dual SG primary loops with each loop having ½ of the plant capacity is estimated to be about a 4% increase relative to using a single SG primary loop. There would also be a similar ROM increase in total steam product cost because the O&M component of product cost due to the added equipment would be expected to increase on the order of this same percentage amount.
- The ROM effect of the capital cost component on steam product cost of using a single main primary loop containing an IHX coupled to a single secondary loop containing a SG is about a 13% increase relative to using a single SG in a primary loop. Again, the total steam product cost would be expected to increase on the order of this same amount.
- The ROM effect of the capital cost component on steam product cost of using dual main primary loops each containing an IHX coupled to a secondary loop containing a SG is

about a 20% increase relative to using a single SG primary loop. Again, the total steam product cost would be expected to increase on the order of this same amount.

- The ROM effect of the capital cost component on steam product cost of using a single main primary loop containing staged IHXs coupled to a single secondary loop containing a SG and a take off (and a return) line for hydrogen process heat is about a 13% increase relative to using a single SG primary loop. Again, the total steam product cost would be expected to increase on the order of this same amount.
- The ROM effect of the capital cost component on steam product cost of using dual main primary loops each containing staged IHXs coupled to a secondary loop containing a SG is about a 22% increase relative to using a single SG primary loop. Again, the total product cost would be expected to increase on the order of this same amount.

The relative economic competitiveness of commercial SC-MHR plants with new coal plants was evaluated based on the above relative ROM cost differences and the cost data in [GCRA 1993]. For the purposes of these evaluations, a commercial VHTR steam-electric co-generation plant was assumed to be similar to the SC-MHR plant in [GCRA 1993]. The conclusions from these relative economic competitiveness evaluations are:

- Adjusting the reactor power from 450 MWt to 600 MWt for the [GCRA 1993] multiple module SC-MHR plant should cause the SC-MHR busbar cost to go from being marginally less competitive with the coal plants (pulverized coal and integrated gasification combined cycle) to being marginally more economic than the coal plants. The cost adders needed today for coal plants to meet environmental requirements would enhance the 4 x 600 MWt SC-MHR plant competitiveness relative to the coal plants.
- A dual loop 4 x 600 MWt SC-MHR plant would have a busbar generation cost about equal to equivalently sized coal plants without added environmental costs but should have an economic advantage relative to the coal plants when the cost adders needed to meet environmental requirements are included.
- SC-MHR plants with IHXs in the PCSs coupled to SGs in secondary loops would probably not be competitive with equivalently sized coal plants even if the coal plant costs were adjusted to meet environmental requirements.

In the foregoing, the buildings and structures costs were assumed to be the same for all of the NGNP alternative HTS configurations. Information on the relative cost differences in the Reactor Building capital costs for alternative HTS configurations is contained in [GA 2008]. The NGNP Reactor Building (RB) cost information in [GA 2008] indicates that:

- The RB for any of the alternatives with SGs in secondary loops is more costly than for the HTS configuration with dual SG primary loops.

- The RB capital cost for the dual SG primary loop configuration was estimated to be 38% less expensive than the RB capital cost for the reference plant given in [PCDSR 2007].

These results reinforce the above conclusions reached on the relative economic competitiveness of SC-MHR plants compared to coal plants. The conclusions relevant to commercial VHTR plants from these relative economic results are as follows:

- The most economic commercial steam-electric VHTR co-generation plant based on the NGNP would be a multiple module plant that employs single primary coolant loops with each loop having a single SG and circulator. This type of plant should enjoy a cost advantage relative to alternative steam-electric co-generation plants..
- If the required circulator capacity is excessive for a single circulator in single SG primary loop plants, dual circulators in the single loops could be used, or dual primary coolant loops could be used. A commercial multiple module VHTR plant based on dual primary coolant SG loops should retain a cost advantage relative to alternative types of steam-electric co-generation plants.
- The economics of commercial steam-electric VHTR co-generation plants that employ primary loops with IHXs coupled with SGs in secondary loops are not expected to be competitive due to the significantly increased capital + O&M cost and decreased availability relative to plants with the SGs in the primary circuit.

RECOMMENDATION: Conceptual VHTR plant designs having alternative HTS configurations should be developed to the same level of detail as done in [GCRA 1993] to enable preparation of more definitive cost estimates and comparative economic evaluations for use in selection of the most suitable HTS configuration. Conceptual VHTR plant designs should be prepared for two equivalent VHTR plants, one with steam generation in the primary system and one with steam generation in a secondary system coupled to the primary system by means of IHX(s). The plant conceptual designs should be for commercial plants. The NGNP design should be established to demonstrate all of the necessary plant characteristics needed to resolve the commercial plant uncertainties (risks).

5.2 Control and Protection

Conclusions and recommendations with regard to consideration of the control and protection requirements for the three alternative HTS configurations for NGNP are as follows:

- Plant Control and Protection Systems can be developed for each of the three HTS Configurations. These can rely on earlier MHR and HTGR control/protection concepts with varying degrees of difficulty. Key concerns are secondary loops incorporated in the reactor heat removal processes, development of dual-production control features, and selecting the most beneficial operational and safety features from the many possible options.

- At the current level of design detail, no clear selection of one HTS configuration can be derived from projection of the necessary control and protection design efforts. The same overall design scope is expected for any of the configurations but the following differences are noted:

HTS Configuration III requires a more rigorous strategy to protect the reactor and vessel system because of potential steam ingress directly into the primary coolant. This may also require more expensive facilities for Steam Generator Isolation and Dump. On the other hand, this configuration requires the least "safety-related" instrumentation and contains the fewest IHX-failure-related "radiation pathways" for primary coolant leakage from the Reactor Building (through secondary piping penetrations). For similar reasons, control algorithm design might be somewhat easier for this configuration as well. Adaptability to NGNP requirement changes, such as changing the desired ratio of process hydrogen output to plant electric output, might favor HTS configuration I.

RECOMMENDATION: The preparation of comparative control and protection system designs for comparable VHTR plants should be part of the development of the more definitive plant designs. Any control and protection system advantages/disadvantages of the comparable plants with the alternative HTSs would then be more definitively identified.

5.3 Safety

The primary benefit of locating the SG in a secondary circuit, as in HTS Configurations I and II, is the safety benefit of the additional barrier provided by the IHX for control of radionuclides. Locating the SG in a secondary loop provides a reduction in the probability of introducing water into the primary system which can cause oxidation of the core graphite and hydrolysis of the coated particle fuel to release radionuclides.

The safety analysis results contained in [PSID 1992] performed for the reference MHTGR-SC plant were reviewed to gain insights into the relative safety hazards of locating SGs in primary coolant loops. The conclusions reached based on this review are as follows:

- Moisture ingress into the primary coolant system from steam generator leakage is not expected to result in unacceptable average or localized oxidation of either the bulk core moderator graphite or the graphite core support components.
- Moisture ingress into the primary coolant system from steam generator leakage is not expected to result in radionuclide releases in excess of regulatory limits.

- Placement of the steam generator in a secondary loop connected to the nuclear heat source through an IHX should eliminate issues associated with moisture ingress into the core from the steam generator.

However, there are also safety-related issues associated with including an IHX in the primary circuit. These issues include:

- There is the probability a major pressure difference developing between the primary and secondary sections of an IHX. Either the IHX must be designed to as a Class I primary pressure boundary component, or the secondary system must contain Class I isolation valves near to the IHX, or the secondary system must be designed as the primary pressure boundary.
- There is uncertainty that an IHX can be designed as a Class 1 component having a reasonable lifetime taking into account the creep fatigue damage caused by occasional high pressure differentials at temperature.
- There is uncertainty that suitable isolation valves can be developed. No suitable design of large size, high temperature He leak-tight valves exist. Isolation valves will also be required to create a boundary between the primary and secondary systems to avoid the need to design the secondary system to function as a Class I pressure boundary.
- Designing the secondary system to satisfy the requirements of a Class I primary pressure boundary is expected to cause excessive plant costs.

RECOMMENDATION: The comparative safety performance of comparable VHTR plants should be evaluated based on more definitive plant designs in the same fashion as in the preparation of comparable economics as recommended in Section 5.1.

5.4 Maintainability

The dominate maintainability issue addressed for evaluation of the three alternative HTS configurations relates to the requirements for maintaining SGs and IHXs. The basic conclusions reached on this issue are as follows:

- Provisions are needed in the design of SGs and the plant building/structures for finding and repairing water leaks in the heat transfer surfaces. Designs of helically coiled tube-and-shell SGs have been developed in which individual tubes can be inspected and plugged to repair leaks.
- Provisions are required for resolving leaks in IHXs. A desirable solution would be one analogous to steam generator tube plugging where excess heat transfer area is provided in the design to allow for some leaking surfaces to be isolated. For tube-and-shell IHXs,

the approach could be the same as for steam generators. The situation is, however, quite uncertain for IHX designs based on compact concepts.

- Currently, the only known solution for compact IHXs is heat transfer surface replacement, either as complete heat exchanger replacement or replacement of heat exchanger sections.
- Replacement of either complete IHXs or failed sections is envisioned to be considerably more involved than plugging tubes. As a result, compact IHXs present a much more complicated and uncertain maintenance situation for resolution of leakages.
- Uncertainties concerning IHX maintainability, coupled with the creep-fatigue design uncertainties, indicate high uncertainties for NGNP IHX designs based on compact heat exchanger concepts. High uncertainty translates to high risk and, for the NGNP, the risk seems large for demonstration of the VHTR commercial steam-electric co-generation application.
- The risk might be acceptable for the hydrogen production process heat demonstration application that uses about 1/10 the heat of the steam-electric co-generation commercial demonstration application.
- The uncertainties associated with the use of tube-and-shell IHX designs are perceived to be less than those of compact IHXs. Tube-and-shell IHXs are, however, considerably larger and, even though they are amendable to tube plugging, are more prone to requiring replacement than steam generators due to higher tube operating temperatures.
- The large size of tube-and-shell IHXs, including impact on building size, translates into high capital cost and replacement, if required, translates into high maintenance costs. These two effects further enforce in the above economic conclusion section that an IHX in a primary coolant system coupled with steam generation in a secondary system would not be economic for commercial application.

RECOMMENDATION: As part of the effort to develop comparable VHTR steam-electric co-generation conceptual plant designs as recommended in Section 5.1, a reference conceptual design of an IHX should be developed that identifies the primary-to-secondary leakage requirements and the design provisions for meeting the leakage requirements. A part of this effort would be to define the primary pressure boundary. If isolation valves are defined as primary pressure boundary components, sufficient design and analysis work must be done to establish isolation valve feasibility and required design features in sufficient detail to enable preparation of cost estimates.

5.5 Tritium Transport

A design issue of special interest for the NGNP is tritium control. Tritium will be produced in an HTGR by various nuclear reactions. Given its high mobility, especially at high temperatures, some tritium will permeate through the intermediate heat exchanger, steam generator, and hydrogen process vessels, contaminating the product hydrogen and process steam. This tritium contamination will contribute to public and occupational radiation exposures; consequently, stringent limits on tritium contamination in the product hydrogen are anticipated to be imposed by regulatory authorities.

Design options are available to control tritium in an HTGR, but they can be expensive so an optimal combination of mitigating features must be implemented in the design. It would be easier to control tritium transport to NGNP end products if the steam generator is located in a secondary loop (rather than a primary loop) because this HTS configuration would allow for inclusion of a second helium purification system in the secondary loop to remove tritium; however, tritium control will be manageable regardless of whether the steam generator is located within a primary or secondary loop. Consequently, tritium transport control is not considered to be a major factor in determining the location of the steam generator in the NGNP HTS.

5.6 Commercial Prototype

The conclusions reached on the three alternative HTS configurations with regard to being prototypic of a commercial steam-electric co-generation plant based on the depth of the current study are as follows:

- None of the HTS configurations with an IHX in the primary coolant system coupled to a SG in a secondary loop are expected to be economically competitive for a steam-electric co-generation plant and would, therefore, not serve well as an applicable prototype for commercial plant demonstration.
- A VHTR steam-electric co-generation plant having a SG in the primary system should be competitive and would satisfy safety requirements. A plant design for NGNP using this HTS configuration is recommended for further design development and better definition of estimated costs and safety performance.

5.7 Overall Recommendation

Based on the conclusions of the economic, control and protection, safety, maintainability, tritium transport, and commercial prototype evaluations performed in this study, it is recommended that an NGNP plant design that includes the required SG in a primary loop be selected for further design development and better definition of estimated costs and safety performance.

6. REFERENCES

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