**HTGR HIGH-TEMPERATURE
PROCESS-HEAT DESIGN AND
COST STATUS REPORT**

MASTER

**VOLUME II
APPENDICES**

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Appendix A

DESIGN DETAILS — 850°C IDC REACTOR VESSEL

PCRv Structure. As in previous 1170 MWt plant studies, a decision was made to embody the following within the PCRv:

- Four IHX units
- Four circulators (positioned above the IHXs in the same cavity)
- Three CACS units

The major features of the PCRv are given in Table A-1.

The PCRv dimensions are sized to layout considerations. The minimum circumferential ligaments between cavities and the space required for the linear prestressing tendons in the top head determine the outside diameter of the vessel. The height of the PCRv is dictated by the space required for the IHX and the main circulator components. Maintaining the required head thicknesses, the core cavity height is extended by almost six feet in order to accommodate the duct from the main circulator cavity to the core upper plenum, which is at an angle of 48° to the horizontal; all the other major components, such as the CAHE and auxiliary circulators, etc., are designed to fit within the available space of the PCRv height as established above. Because of the 48° inclined duct in the PCRv top head and other complex ducting on the secondary side of the IHX, the PCRv ligaments and the accompanying prestressing intensities have to be verified by analysis and suitable adjustments made to the PCRv size and prestressing as required. Provision has been made for all the secondary ducting to exit the PCRv vertically downward at the bottom, and cutouts are shown in the PCRv support ring at these locations. Routing of these pipes from the underside of the PCRv was a design endeavor performed by the architect-engineer.

Table A-1

MAIN FEATURES OF PCRV FOR 850°C IDC PLANT

PCRV concrete strength	6500 psi
LPS tendon strength (at GUTS)	2478 kips
CPS cable strength (at GUTS)	41.3 kips
Refueling scheme	In-vessel refueling (see memo 631:110:TFII:81 dated 4/29/81 for details of design)
Closures	
Intermediate heat exchanger cavity (with main circulator on top)	Precast concrete prestressed ring
CAHE cavity	Steel dome
CAHE type	Compact bayonet

A plan view of the PCRV is shown in Figure A-1. The plan shows an arrangement with a centralized core cavity and orientation of the major equipment side wall cavities to yield a PCRV of minimum diameter. An elevation view of the PCRV is shown in Figure A-2, illustrating the primary system gas flow paths. The primary coolant passes through the lower hot duct from the core to the IHX and returns (through an inclined duct) to the core cavity upper plenum via the main circulator cavity located above the IHX, traveling downward on the shell side, accumulating heat from the primary coolant and exiting the PCRV at the bottom onto a cluster of four PCPVs located outside the reactor containment building. Pipe chases are provided for those secondary inlet and outlet pipes in the PCRV. The major PCRV parameters are given in Table A-2.

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Table A-2

MAJOR PCR V PARAMETERS FOR 850°C IDC PLANT

Type	Multi-cavity PCR V
Overall dimensions	
Diameter, ft	87.00
Height, ft	90.50
Core cavity, quantity	1
Diameter, ft	31.5
Height, including in-vessel refueling, ft	66.00
Intermediate heat exchanger/ main circulator cavity, quantity	4
Diameter:	
Mid height, ft	12.14
Top, ft	11.14
Depth from top of PCR V, ft	78.75
CAHE cavity, quantity	3
Circulator cavity:	
Diameter:	
Mid height, ft	6.67
Top, ft	8.00
Depth from top of PCR V, ft	21.25
CAHE bundle cavity:	
Diameter:	
Mid height, ft	6.00
Top, ft	7.50
Depth from bottom of PCR V, ft	20.50
Maximum cavity pressure, psig	776
PCR V support	Concrete ring support with center pedestal

PCR V Liners, Penetrations, and Closures. The steel cavity liners, penetrations, and penetration closures form the continuous gas-tight boundary of the PCR V. The liner and penetration anchors transmit loads from internal equipment support structures and axial loads from closure to the PCR V concrete. A liner cooling system is included to remove the heat transmitted through the thermal barrier before it reaches the concrete. The liners, penetrations, and closures are similar to those of recent HTGR-SC designs where similar components are housed. The HTGR-PH, however, requires a new closure design for the intermediate heat exchanger cavity; this new design is briefly outlined below.

The top cap of the cavity liner is welded to the liner after the heat exchanger is installed. The prestressed concrete closure, containing a housing for the main circulator, is placed in position on the top of the PCR V, concentric with the cavity top cap. The bottom end of the circulator housing is welded to the liner top cap, forming an annulus between the top cap and closure. This annulus is filled with grout by means of small penetrations extending through the closure. The closure is retained with the PCR V vertical tendons.

An internal dome closure, located in the upper end of the IHX cavity, separates the primary coolant from the secondary coolant. If an accidental loss of secondary coolant occurs, the closure is subjected to the full reactor pressure of its external surface. A flange and ring forging with shear anchors is therefore provided to transmit the downward axial force from the IHX closure to the PCR V concrete.

PCR V Thermal Barrier. The thermal barrier has been separated into 19 zones according to service temperature and liner geometry considerations, with four different material selections made for these zones. The preliminary thermal barrier sizing calculations proceeded according to the following sequence:

- Thickness determination based upon insulation properties. A factor of two times the thermal conductivity was used. Therefore, the fibrous insulation thickness is approximately twice that which would result in the maximum liner overall temperature of 150°F.
- Thickness determination based on hot spot examination. The effect of attachment fixtures on thickness was determined in accordance with a maximum liner hot-spot temperature limit of 250°F.
- Final determination of thickness values based on the results of the above two methods, plus any additional design factors.

The types of materials selected for the various thermal barrier components are detailed in Table A-3. The materials were chosen for their ability to withstand the particular temperature environment. Using creep as a criterion, Type 316 stainless steel has been limited for use to 1150°F. The size of these cover plates is governed by the acoustic environment, which is assumed similar to that of the steam cycle plant.

Hastelloy-X was selected for the next higher temperature range thermal barrier based on its creep resistance and resistance to decarburization. Hastelloy-X was also chosen for the seal sheet material because of its decarburization resistance. The insulation blankets for the above two grades of thermal barrier consist of a composite of Saffil Alumina HT and Kaowool. On the basis of resiliency, Kaowool is being limited to 900°F for long-time exposure.

Inconel 713LC, a cast nickel-base superalloy, was selected for the cover plates of the lower core cavity sidewall, CAHE cavity, lower intermediate heat exchanger cavity, and the hot duct design. The basis for this selection was reasonable creep resistance, castability, and resistance to decarburization. The size was determined by acoustics and casting state-of-the-art. The Huntington oxide dispersion-strengthened alloy MA-956 was chosen as the seal sheet material because of its decarburization resistance. The

Table A-3

THERMAL BARRIER MATERIAL SELECTION FOR 850°C IDC PLANT

Cover Plate	Seal Sheet	Blocks	Pads	Insulation
Type 316 stainless steel	Type 316 stainless steel	—	—	Saffil + Kaowool
Hastelloy X	Hastelloy X	—	—	Saffil + Kaowool
Inconel 713LC	MA 956	—	—	Saffil
Type 316 stainless steel	Type 316 stainless steel	Graphite	Pyrolytic graphite, alumina, fused silica	Saffil + Kaowool

insulation blankets are all Saffil because of its high resiliency and low compression force (hence, low loads applied to the cover plates).

The bottom head thermal barrier of the core outlet plenum differs from the standard system in degree of complexity. The function of the bottom heat thermal barrier is not only to protect the PCRV liner but also to provide a stabilized insulated structural base for the graphite core support posts. The configuration consists of layered polygonal graphite blocks with insulation blankets through which a series of ceramic support columns penetrate. The polygonal blocks are exposed to the direct gas stream and hence, the highest core outlet temperatures. Here, the main problem is to dissipate the gas streaks, thereby minimizing the thermal shock imparted to the substrate layers. The support columns consist of pads which are sized to accommodate the mechanical loads transmitted through the support posts (including seismic conditions) as well as to act as insulators. The thermal loads generally dictate the thicknesses of the pads. Pyrolytic graphite is designated for the top pad. High purity (85%) alumina is designated for all remaining pads with the exception of the bottom pad, which is the final insulator. The material for the bottom pad is a high density, fine grain silica.

APPENDIX B

Appendix B

DESIGN DETAILS — 850°C IDC PRIMARY COOLING SYSTEM

Intermediate Heat Exchanger (IHX). Efforts continued in FY81 to establish an improved IHX from both the structural and economic standpoints. Insufficient funds were appropriated for a full engineering evaluation to be performed (i.e., survey of different configurations such as straight tube, U-tube, helical bundle, etc.). A new reference IHX design configuration was selected for plant layout purposes and update cost estimates. While the straight-tube concept was retained, the secondary system gas flow (outside the tubes) was changed from axial flow to multipass cross counterflow for the following reason.

The primary problem area which prompted the change to the crossflow concept was associated with the tube-to-tube differential expansion in the axial flow concept brought about by the effects of hot streaks entering the cavity. In addition, the effects of nonuniform flow distribution across the tube bundle on the shell side due to the restrictive nature of the crossflow into and out of the center regions tended to compound the differential expansion problems. Modifications to the concept were conceived, including monolithic counter crossflow and modular counter crossflow concepts. After consideration of inherent problem areas, effects on the PCRV, and unit costs, it was decided that the counter crossflow monolithic arrangement with the primary gas on the tube side showed the most promise for an updated reference design.

Additional problem areas addressed were:

- Design and analysis of an acceptable and licensable thermal expansion joint
- Preliminary evaluation of a segmented tubesheet to minimize tubesheet size
- Preliminary study of the structural adequacy of the tubes as vertical support members

The use of a cross counterflow configuration has several primary advantages:

- Achieves a more uniform flow distribution on the shell side, thereby minimizing thermal expansion differences between the tubes from this source
- Provides room in the bundle cavity for the inclusion of individual tube expansion loops to allow for thermal expansion differences which may exist due to hot streaks or other causes
- Allows a more positive method of sealing against circumferential bypass flow on the shell side

The current reference IHX is a monolithic straight-tube gas-to-gas baffled cross counterflow assembly as shown in Figure B-1. The baffles are of the disk and doughnut type, causing the shell side flow path to flow radially in and out across the tubes with each pass, utilizing center and peripheral tubeless areas for turning. The primary gas (heating gas) is on the tube side and makes a single pass through the tubes. The secondary gas (heated gas) is on the shell side and makes eight passes across the tubes.

The tubes are fabricated of Inconel 617 and have a wall thickness capable of withstanding the full life operating pressure which, though nearly pressure balanced, carries a small external or compression pressure load. In addition, the tubes are designed to withstand the full internal primary gas pressure for a total period of up to two hours in the event of loss of secondary loop pressure. The tubesheets are single piece forgings drilled and machined to the final configuration. The hot tubesheet is fabricated of Inconel 617, while the cold tubesheet is Inconel 800H.

NOTES:

1. MANUFACTURE IN ACCORDANCE WITH ASME BOILER AND PRESSURE VESSEL CODE SECTION III, DIVISION 1.
2. ALL DIMENSIONS ARE GIVEN IN NOMINAL COLD CONDITION.
3. ALL DIMENSIONS IN BRACKETS [] ARE IN MILLIMETERS.

	TUBE SIDE	SHELL SIDE
H ₂ INLET °F (°C)	155 (62.7)	650 (313.3)
H ₂ OUTLET °F (°C)	795 (433.3)	
H ₂ INLET PSIA (BAR)	701 (48.1)	718.7 (48.89)
H ₂ SP PSIA (BAR)	9.2 (.63)	11.7 (.80)

ITEM	PART NO.	DESCRIPTION	MAT/MATL SPEC
1	17	DOWNCOMER R. 102" OD V. 88" ID x 1" THK	ALLOY 800H 58.408' 481
1	16	SUPPORT FLOWSHIP 110" DIA 35" THK 15' LG	
1	15	TUBESHEET FLOWSHIP 110" DIA 24" LG	
1	14	FLANGE 4" THK x 24" LG	ALLOY 800H 80.408' 481
1	13	SUPPORT FLOWSHIP	2 1/2" CR - 140 54.350' 481
1	12	STIFFENER R. 35" WALL	
1	11	STIFFENER R.	25.02 - 140 54.350' 481
1	10	STIFFENER R.	ALLOY 800H 58.408' 481
1	9	CYLINDER 62" DIA x 35" WALL	25.02 - 140 54.350' 481
1	8	FLANGE 36" THK x 35" LG	ALLOY 800H 58.408' 481
1	7	FLANGE 36" THK x 35" LG	ALLOY 800H 58.408' 481
1	6	FLANGE 36" THK x 35" LG	ALLOY 800H 58.408' 481
1	5	FLANGE 36" THK x 35" LG	ALLOY 800H 58.408' 481
1	4	FLANGE 36" THK x 35" LG	ALLOY 800H 58.408' 481
1	3	FLANGE 36" THK x 35" LG	ALLOY 800H 58.408' 481
1	2	FLANGE 36" THK x 35" LG	ALLOY 800H 58.408' 481
1	1	FLANGE 36" THK x 35" LG	ALLOY 800H 58.408' 481

REQD/ASSEMBLY		HTGR-PH 1170 MW (1) 4-LOOP		850°C INDIRECT CYCLE	
DATE		21		7200	
LTR DATE		ISSUE DESCRIPTION		DR. CHK. DES. APPD. APPD.	
PRELIMINARY		PRELIMINARY		PRELIMINARY	
DATE		ISSUE DESCRIPTION		DR. CHK. DES. APPD. APPD.	

Figure B-1. Intermediate Heat Exchanger Configuration

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The tubes are welded to the hot (lower) tubesheet by means of internal bore fusion welds with the tubes butted to spigots machined into the plate upper face. At the upper end of the bundle, the tubes are welded to the cold tubesheet after having been formed into Z-shaped expansion loops or offsets. The purpose of the offsets is to accommodate the differential expansion of those tubes which may be subjected to higher than average shell side gas temperatures. The offsets are shaped to utilize the center turning section of the bundle, thereby forming a homogeneous tube field at the cold tubesheet as opposed to the annular or ring-shaped hot tubesheet hole pattern. The tubes above the offsets penetrate the tubesheet and are welded to the top surface.

The tubes are supported laterally by the ring- and disk- (disk and doughnut) shaped baffles, all of which are supported by the outer shroud. These baffles, three disk-shaped and twelve ring-shaped, are located to route the shell side helium flow radially across the tubes eight times during its passage through the IHX. A peripheral shroud is provided around the tube bundle which is sealed against bypass helium flow between it and the cavity liner. The shroud has flow "windows" to admit and discharge the shell side gas at the top and bottom, respectively.

The IHX is located entirely in the PCRV and is welded at the lower end to a liner extension support. The upper end of the unit is attached to a primary/secondary gas boundary dome via a bellows/seal assembly, which compensates for IHX axial thermal expansion. Primary gas flow restrictors are provided at each end of the unit to guard against the unlikely simultaneous failure of the tubesheet/head weld and the secondary piping outside of the PCRV.

Primary helium from the core enters the IHX at the bottom, flows upward through the tubes, and exits at the top to the circulator located in the same cavity, where it is compressed and returned to the reactor. The secondary helium enters the IHX cavity at the top and flows radially

through the bundle to the empty central section. It then turns 90° and flows downward through the bundle in a disk and doughnut path to the bottom, where it exits the bundle in a radial direction.

Access has been provided to tube ends, tubesheets, and headers for tube leak detection and sealing as well as for inservice inspection deemed necessary to confirm the heat exchanger integrity. All operations can be accomplished external to the unit cavity using remote handling methods via access penetrations.

The IHX has been designed for replaceability. Following removal of the cavity plug, the unit can be separated from the liner by cutting two primary-to-secondary gas boundaries. At the lower end, this is done at the tubesheet assembly-to-liner interface, while at the upper end, it is done at the dome-to-liner interface. Once separated, the IHX can be withdrawn from its cavity. Installation takes place by the reverse process.

Preliminary results of investigations into the design of a cold primary gas duct expansion joint indicate that adapting a typical bellows design to the large diameter (36 inch ID) duct that will accommodate the large thermal expansion (up to 10 inches), be able to withstand a total depressurization on one side while soaking at high temperature, and be inspectable and replaceable will be quite difficult. Several alternate approaches to the design have been proposed. The most attractive approach is a typical convoluted bellows design which is actively cooled and backed up with a safety class helium source that will maintain a design level pressure differential across the bellows in the event of the loss of secondary loop pressure.

It is recognized that the IHX is a critical component in the 850°C IDC plant and that extensive design studies are required to identify a design concept that satisfies all of the criteria. Details of the current

reference design are given in Table B-1. A further evaluation of a straight tube variant resulting from FY81 endeavors has been outlined above. However, the concept is still in an embryonic form, and is characterized by the following adverse features:

- Exchanger support from the hot end of the assembly
- A very demanding bellows necessary to accommodate thermal expansion
- High capital cost

From the open literature, it has been observed that in related IHX endeavors in Europe and Japan, a helical bundle geometry has been selected for indirect cycle nuclear process heat plants. Future design efforts should be expended in the design and evaluation of a helical geometry concept, with the goal of realizing an IHX of improved structural integrity and reduced cost.

Primary System Main Helium Circulator. For the revised cycle parameters, the design status of the primary system circulator was updated. Initial studies indicated that a design based on a single-stage centrifugal compressor would be adequate for the pressure head rise associated with the indirect cycle system. While the cycle parameters obviously differ from the HTGR-SC/C plant, it was found that advantage could be taken of the lead plant circulator design effort, and indeed the major features of the circulators for the HTGR-SC/C and PH plants bear a close resemblance.

The primary system circulator consists of a single-stage centrifugal compressor impeller mounted to an overhung shaft support by a bearing housing and rigidly coupled to a synchronous drive motor. Additional elements are the compressor diffuser and the inlet flapper check valve. Figure B-2 shows a typical installation.

Table B-1

DETAILS OF INTERMEDIATE HEAT EXCHANGER FOR 850°C IDC PLANT

Type	Straight Tube, Cross Counterflow
Design Life, yr	20
Number of Tubes	14,049
Tube Size (OD/Wall Thickness), in	0.5/.04
Tube Pitch, in	.688
Tube Pitch Pattern	Triangular
Active Tube Length, ft	35.75
Overall Height, ft	49
Shroud OD, in	112
Shroud Flange Diameter, in	116
Upper Cone Flange Diameter, in	126
Empty Weight, lb	405,000
Primary Coolant (Tube Side) Conditions:	
Flow Rate, lb/hr	1,086,000
Temperature, In/out, °F	1556/793
Inlet Pressure, psi	707
Pressure Loss, psi	9.5
Secondary Coolant (Shell Side) Conditions:	
Flow Rate, lb/hr	1,019,000
Temperature, In/out, °F	650/1460
Outlet Pressure, psi	707
Pressure Loss ^(a) , psi	12

^(a) Does not include allowance for flow maldistribution

Figure B-2. Primary System Circulator Installation

B-9

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The bearing housing utilizes water-lubricated hybrid bearings to provide radial positioning of the compressor rotor. A buffer helium labyrinth seal system is used to provide separation between the reactor coolant and the bearing lubricating water. Further, the bearing water is sealed from the containment atmosphere with a sliding shaft seal. The synchronous drive motor and the bearing housing are both mounted on the PCRV liner. A section of drive shaft between the drive motor and bearing housing is removable, allowing for maintenance of the shaft sliding seal without the removal of the drive motor or the bearing housing. The major compressor parameters for the primary system circulator are given in Table B-2.

Core Auxiliary Cooling System (CACS). The CACS consists of three forced circulation cooling loops. Each loop contains a core auxiliary heat exchanger (CAHE) and an auxiliary circulator assembly including a drive motor and loop shutoff valve. These components are located in PCRV cavities peripheral to the central reactor core cavity. The CACS cavities are connected to the central cavity by appropriate cross ducts.

Each of the three CACS loops is fully capable of removing the core residual and decay heat at a rate for safe cooldown from 102% of rated reactor power level under pressurized conditions. Two loops are required for cooldown from the same operating conditions when the PCRV is depressurized. In either case, the cooling capability is such that the temperatures of all components in the PCRV are maintained within their specific safe limits. The design basis CACS performance is given in Table B-3. This performance is from the 1170 MWt HTGR-PS/C effort, but it is judged to be adequate for conceptual direct cycle HTGR-PH evaluations.

Table B-2

PRIMARY CIRCULATOR DETAILS FOR 850°C IDC PLANT

Inlet pressure	696.3 psi
Inlet temperature	796°F
ΔP	28.7 psi
Head rise	20,000 ft
Mass flow	302.01 lb/sec
Rotational speed	3529 rpm
Specific speed	80.23
Compressor type	Single stage centrifugal
Compressor OD	61.16 in
Compressor tip speed	942 ft/sec
Compressor efficiency	82.5%
Compressor power	13,311 hp
Circulator drive	Electric motor

Table B-3

CACS PERFORMANCE
(DATA FOR 1170 MWt HTGR-SC/C BUT ASSUMED REPRESENTATIVE FOR HTGR-PH)

	Depressurized PCRV		Pressurized PCRV
	Pure He	Air Ingress	
CACS loops operating	2	2	1
Primary coolant molecular weight	4.0	12.0	5.0
Primary coolant pressure, psia	23.6	23.6	1050.0
Heat duty per CACS loop, Btu/hr	4.557+07	3.896+07	1.414+08
Primary coolant circuit			
Flow per CACS loop, lb/hr	30,861	68,113	116,352
Core outlet temperature, °F	1746	1746	1580
CAHE inlet temperature, °F	1746	1746	1580
Core inlet temperature, °F	557	465	700
Pressure drop, psia		.47	
CAHE		.39	
Core		.05	
Ducts and plena		.03	
Secondary (CACWS) circuit			
Mass flow per CACS loop, lb/hr	5.396+05	5.409+05	5.107+05
Pump volumetric flow, gpm	1100	1100	1100
Volumetric flow at CAHE outlet, gpm	1136	1129	1363
CAHE inlet temperature, °F	165	157	292
Air blast heat exchanger inlet temperature, °F	248	228	544
Pressure drop, psia			207
CAHE			3
Piping and air blast HX			205

Appendix C

DESIGN DETAILS — 850°C IDC SECONDARY HELIUM SYSTEM

PCPV Structure. Each of the four PCPV structures comprises two reformer cavities (GE design) and one steam generator cavity (GA design). It also contains one cooling water header pit and one pressure relief pit. The PCPV general arrangement is shown in Figures C-1 and C-2 for plan view and elevation, respectively.

The secondary coolant from the intermediate heat exchanger (IHX) in the PCRV enters the reformer cavities by means of ducts at the bottom of the PCPV. The coolant exits both reformer cavities to a single steam generator at the top and flows through the shell side of the component. The coolant then leaves the steam generator cavity and returns to the IHX in the PCRV. Four PCPVs are required to complete all the lines from the IHX. It is possible to consolidate all four loops in one multiloop PCPV which has been found to be more economical than four single loop PCPVs.

The PCPV dimensions are controlled by layout considerations. The minimum circumferential ligaments between cavities and the space required for linear prestressing tendons determine the outside diameter of the vessel. The height of the PCPV is dictated by the space required for the reformer cavity. All the other component cavities, such as steam generator, pressure relief, and cooling water system, are designed to fit within the available space in the height of the PCPV.

PCPV Liners, Penetrations, and Closures. The steel cavity liners, penetrations, and penetration closures form the continuous gas-tight boundary of the PCPV. The liner and penetration anchors transmit loads from

internal equipment support structures and axial loads from the closure to the PCPV concrete. A liner cooling system is included to control the heat emitted through the thermal barrier before it reaches the concrete. The PCPV has a new closure design for the steam generator cavity. This new closure is described below.

The top cap of the cavity liner is welded to the liner after the heat exchanger is installed. The prestressed concrete closure, containing a man access penetration, is placed in position on the top of the PCPV, concentric with the cavity top cap. The bottom end of the man access penetration is welded to the liner top cap, forming an interspace between the top cap and closure. This interspace is filled with grout through ducts extending through the closure. The closure is retained with the PCPV vertical tendons.

The reformer cavity configuration and its closures are dictated by GE requirements. Their design includes a dome closure which is recessed in the former cavity and is attached to a large ring forging, cast integral with the PCPV, and has a sleeve and flange that extends into the cavity. The reformer is retained with this flange. The axial load from the reformer is transmitted from the ring forging into the PCPV. For biological shielding purposes, there is a solid concrete slab to be supplied by others, at the top of the reformer cavity.

PCPV Thermal Barrier. The thermal barrier has been separated into ten zones, according to service temperature and liner geometry considerations. Three different material selections have been made for these zones according to hot surface temperature. The preliminary thermal barrier sizing calculations proceeded according to the following sequence:

- Thickness determination based on insulation properties. A factor of two times the thermal conductivity was used. Therefore, the fibrous insulation thickness is approximately twice that which would result in the maximum liner overall temperature of 150°F.

PLAN - PCPV TOP HEAD

6. LINER THICKNESS TO BE $\frac{1}{2}$ " (0.01M) EXCEPT WHERE NOTED OTHERWISE.
7. INTERCONNECTING PIPING TO CONSIST OF 1800 FEET (549.24M) OF $1\frac{1}{4}$ " (0.03M) SCHEDULE 40 PIPE.
8. ALL LINER STUDS TO BE $\frac{3}{4}$ " (0.02M) DIA. X LENGTH SHOWN ON THE DRAWING. PROVIDE ONE STUD PER 50 SQ IN. (0.03 SQ M.) OF LINER SURFACE WHERE SHOWN ON THE DRAWING.

GENERAL NOTES:

1. THIS PCPV IS IN GENERAL COMPLIANCE WITH THE ACI 318-77 BUILDING CODE REQUIREMENTS.
2. MATERIAL PROPERTIES AND SYSTEM PARAMETERS OF THE MAJOR STRUCTURAL COMPONENTS USED IN THE PCPV DESIGN ARE AS FOLLOWS:
 - a. SPECIFIED CONCRETE COMPRESSIVE STRENGTH AT 60 DAYS = 6500 PSI (44.82 MPa) FOR PCPV AND PRECAST PANELS; 8000 PSI (55.16 MPa) FOR STEAM GENERATOR CONCRETE CLOSURE.
 - b. BONDED REINFORCEMENT PER ASTM A615, GR 60.
 - c. LINEAR PRESTRESSING: 60- $\frac{1}{2}$ " ϕ , 7-WIRE STRAND, TENDONS - MAX. CAPACITY = 2478 KIPS (G.U.T.S.)
 - d. CIRCUMFERENTIAL PRESTRESSING: $\frac{1}{2}$ " ϕ , 7-WIRE STRAND CABLES - MAX. CAPACITY = 413 KIPS (G.U.T.S.)
 - e. MAXIMUM CAVITY PRESSURE (MCP) = 776 PSI (53.5 MPa)
 - f. LINER COMPONENT DATA/ENVELOPE PER GA MEMO NO. 513-1063-81, DATED 5-8-81.
3. DIMENSIONS AND OPENINGS SHOWN IN THE PCPV SUPPORT STRUCTURE ARE SUGGESTED ARRANGEMENTS ONLY.
4. THE FEASIBILITY OF THIS GENERAL ARRANGEMENT IS SUBJECT TO THE FOLLOWING CONSIDERATIONS:
 - a. CONCRETE LIGAMENTS TO BE VERIFIED BY ANALYSIS.
 - b. LAYOUT STUDIES TO BE MADE FOR POSSIBLE TENDON INTERFERENCE.
 - c. COOLING WATER SYSTEM REQUIREMENTS.
 - d. REFERENCE DRAWINGS USED IN THE DEVELOPMENT OF THE PCPV DESIGN:
 - 1) REFORMER - G.E. MEMO NO. YL-270-10085, DATED 4-30-81.
 - 2) STEAM GENERATOR - 179 MW (4) INDIRECT CYCLE, GENERAL ARRANGEMENT DWG NO. 026871/1.
 - 3) PCPV GENERAL ARRANGEMENT - GA DWG. NO. 026893/1.
5. LINER MATERIALS ARE CARBON STEEL EXCEPT AS NOTED:
 - PLATE TO BE SA-537, CL 2.
 - FORGINGS TO BE SA-508, CL 2.
 WHERE MATERIAL IS INDICATED AS 2 $\frac{1}{4}$ CHROME:
 - PLATE TO BE SA-387, GR 22, CL 2.
 - FORGINGS TO BE SA-336, CL F 22.

QUANTITIES:

1. CONCRETE:

PCPV - 6500 PSI (44.82 MPa)	4600 CY
PRECAST PANELS - 6500 PSI (44.82 MPa)	450 CY
ST. GEN CLOSURE RING - 8000 PSI (55.16 MPa)	37 CY
2. REINFORCEMENT (ASTM A615, GR 60):

PCPV	175 TONS
PRECAST PANELS	60 TONS
ST GEN CLOSURE RING	7 TONS
NO. OF MECHANICAL SPLICES IN THE PCPV	1000
3. PRESTRESSING - LPS:

NO. OF 60- $\frac{1}{2}$ " ϕ STRAND TENDONS	60
LENGTH OF TENDONS BETWEEN CONCRETE SURFACES:	
QUANTITY	LENGTH
REFORMERS AND PERIPHERAL	46
STEAM GENERATOR	14
	84 LF
	89 LF

* ALLOW 5 LIN FT ADDITIONAL LGTH PER TENDON FOR TENSIONING.
4. PRESTRESSING - CPS:

$\frac{1}{2}$ " ϕ (0.01M) STRANDS - TOTAL LENGTH	11 x 10 ⁶ LF
$\frac{3}{8}$ " ϕ (0.01M) STRANDS - TOTAL LENGTH	17 x 10 ⁶ LF
NO. OF $\frac{1}{2}$ " ϕ (0.01M) STRAND LAYERS	124
NO. OF $\frac{3}{8}$ " ϕ (0.01M) STRAND LAYERS	5
NO. OF 30° PANELS	126
NO. OF LOAD MONITOR PANELS	6
5. INSTRUMENTATION:

NO. OF LPS LOAD CELLS	3
NO. OF CPS LOAD MONITORS	6
NO. OF PCPV SENSORS	200
NO. OF LINER SENSORS	150
NO. OF PCPV SPARE SENSORS	20
NO. OF LINER SPARE SENSORS	15

ITEM		PART NO.		DESCRIPTION		MATL/MATL SPEC	
NEXT IDENTIFIED DOCUMENT							
026873							
REQD/ASSEMBLY	DISC	SYSTEM	TYPE	PROJECT	PARTS LIST		
	S	29	DLO	7200			
HTGR-PH, 1170 MW(t)					DIST.		
					GENERAL ATOMIC COMPANY SAN DIEGO, CALIFORNIA		
TITLE					PCPV GENERAL ARRANGEMENT 850°C SECONDARY LOOP		
SIZE					CODE IDENT NO		ISSUE
E					32334		026915
SCALE					GAL-1, A/L-2		SHEET 1 OF 2

UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES NO DIMS OR SHARP EDGES DIMENSIONS PER ANSI Y-14.5 TOLERANCE: DECIMAL FRACTION ANGLE XXX ± .XX ± .XX ALL MACHINED SURFACES DO NOT SCALE PRINT							
DATE	ISSUE DESCRIPTION	DR	CHK	DES	APPD	APPD	
1/1/81	CONCEPTUAL						

Figure C-1. PCPV Plan View

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										<div>NON-CONTROLLED COPY EXCEPT ISSUE STATUS WITH DOCUMENT CONTROL PRIOR TO USE</div>	
<div></div>				ITEM	PART NO.	DESCRIPTION				MATERIAL SPEC	
REQD/ASSEMBLY						PARTS LIST					
HTGR-PH, 1170MW(t)						DIST.		<div> GENERAL ATOMIC COMPANY SAN DIEGO, CALIFORNIA</div>			
<div>UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES NO BURRS OR SHARP EDGES DIMENSIONS PER ANG-Y-14.5 TOLERANCE: DECIMAL FRACTION ANGLE XXX ± .XXX ± XXX ± .XXX ± ALL MACHINED SURFACES DO NOT SCALE PRINT</div>				<div></div>		TITLE				ISSUE	
						PCPV GENERAL ARRANGEMENT 850°C SECONDARY LOOP				1	
SEE SHEET 1						SIZE	CODE (IDENT NO)	DWG. NO.			
						E	32334	026915			
						SCALE (A/L-Y-7) GAL				SHEET 2 OF 2	
LTR DATE		ISSUE DESCRIPTION				DR. CHK. DES. APPD. APPD.					

Figure C-2. PCPV Elevation View

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- Thickness determination based on hot spot examination.
The effect of attachment fixtures on thickness was determined in accordance with a maximum liner hot-spot temperature limit of 250°F.
- Final determination of thickness values based on the results of the above two methods plus any additional design factors.

The types of material selected for the various thermal barrier components are outlined below.

Material Code	Cover Plates	Material Seal Sheets	Insulation
1	Low carbon steel	Low carbon steel	Kaowool
2	Type 316 stainless steel	Type 316 stainless steel	Kaowool plus Saffil
3	Inconel 713LC	Hastelloy X	Kaowool plus Saffil

The materials were chosen for their ability to withstand the particular temperature environment. Using creep as a criterion, low carbon steel and Type 316 stainless steel have been limited for use to 700°F and 1150°F, respectively. The size of these cover plates is governed by the acoustic environment, which is assumed similar to that of the steam cycle plant and by the desire to maintain commonality with the PCR thermal barrier as much as possible.

Inconel 713LC, a cast nickel-base superalloy, was selected for the cover plates of the reformer cavity. The basis for this selection was reasonable creep resistance, castability, and resistance to decarburization. The size was determined by acoustics and casting state-of-the-art. Hastelloy X was chosen as the seal sheet material.

The insulation blankets for the low temperature thermal barrier consist of Kaowool. On the basis of resiliency, Kaowool is being limited to 900°F

for long-time exposure. For the higher temperature thermal barriers, a composite of Saffil Alumina HT and Kaowool has been selected.

The helium hot leg temperature (1460°F) requires internal insulation to maintain the pipe wall temperature within code limits. Two internal insulation concepts are under study. One consists of a cast nickel base alloy (Inconel 713LC) inner liner with high temperature fiber insulation between the Inconel liner and the pipe wall, as shown in Figure C-3. The second concept utilizes a refractory liner widely used in the refinery/process industry. The refractory inner liner consists of a cast-in-place smooth hard liner anchored to the pipe by metal anchors. Between the hard liner and the pipe wall is a lighter insulating refractory. Figure C-4 is a cross section of the refractory-lined helium hot leg piping.

An even more difficult technical problem than the hot leg insulation is the hot leg isolation valves, which are exposed to temperatures well above the design temperatures of ASME Section III high temperature code cases. No satisfactory solution has yet been proposed.

Figure C-3. Secondary Helium Hot Leg Internal Insulation (Inconel Supported Fiber Ring Concept)

DETAIL "A"
TYPICAL PIPE WELD

Figure C-4. Secondary Helium Hot Leg Internal Insulation
(Refractory Insulation Liner Concept)

Appendix D

DESIGN DETAILS — 850°C IDC STEAM GENERATOR

A layout of the indirect cycle plant steam generator is shown in Figure D-1. Table D-1 gives details.

The concept selected for the process heat plant is the Mark IV-A steam generator used in the HTGR steam cycle, the difference being that it is installed in a PCPV instead of a PCRV. The process heat plant steam generator is designed (and will be fabricated) to ASME Section VIII, Div. 1 requirements.

Flow paths are similar to the in-vessel Mark IV-A concept; hot helium enters the bottom of the steel vessel, flows upward through the straight superheater, turns 180° at the top of the straight superheater to flow down through the EES coil, and then flows out of the unit at the bottom of the coil. Water enters the unit at the feedwater tubesheet just below the EES coil, rises to the coil in individual tubes, spirals upward in a helical fashion to the top of the coil, crosses to the center via expansion loops above the gas flow, and flows downward through the straight superheat tubes to the superheat tubesheet. The EES inner shroud is tied to the shell with a conical section below the feedwater nozzle and with a perforated horizontal plate above the EES coil. The straight superheater shroud is supported radially from the EES inner shroud at the bottom and hung from the gas turning vane at the top. The EES support plates are each supported by a series of long bars from the conical section for dead weight loads and by the shrouds for lateral loads.

Materials are the same as the in-vessel MK-IVA. Tubing (and tubesheet) is 2-1/4 Cr - 1 Mo and Alloy 800H with a bimetallic weld in the quiescent zone at the top of the unit; support plates are 2-1/4 Cr - 1 Mo, and shrouds are 304 and 316 stainless steel. The concept provides 187°F of superheat at the bimetallic weld. The weld has a nominal operating temperature of 811°F. The other critical area, the top of the 2-1/4 Cr core superheater, has a nominal maximum temperature of 906°F with a 30°F gradient. All of the above values are regarded as being satisfactory.

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Table D-1

STEAM GENERATOR DETAILS FOR 850°C IDC PLANT

Number of units/plant	4
Unit rating	178 MWt
Unit OD	125 in
Overall length	55 ft
Number of tubes	215
Tube size:	
FW, EC, EV, SH-1	1.00 OD x .12 wall x 255 ft long
ST-SH	1.00 OD x .074 wall x 56 ft long
Design conditions:	
	<u>Inlet</u> <u>Outlet</u>
Helium temperature	1101°F 620°F
Helium pressure	691 psia 681 psia
Helium mass flow	1.02×10^6 lb/hr
Water temperature	356°F 1000°F
Water pressure	2300 psia 1800 psia
Water mass flow	0.53×10^6 lb/hr

APPENDIX E

Appendix E

HEAT CYCLE EVALUATIONS — 850°C IDC PLANT

Although a multitude of potential heat cycles were considered in the evaluation of options, the main effort was directed to comparison of the following three reformer train/turbine plant configurations:

- Case A: thermally driven heat cycle
- Case B: compression driven heat cycle
- Case C: direct steam injection heat cycle

The following approach was used in evaluating these cases:

- Reviewing prior reports and documents on HTGR-R heat cycle designs
- Comparing conceptual designs for the three heat cycle cases using a consistent design basis
- Selecting the most promising heat cycle case by using a screening methodology to rate the operability as well as the economic and efficiency factor for the cycles

The evaluation of the three heat cycle cases was based on the design conditions used in General Electric's Corporate Research and Development report "HTGR-R Lead Project-Reformer Heat Exchange and Steam Turbine Cycle," dated July 11, 1980. This design basis is summarized in Table E-1. For the basic designs, an effort was made to minimize interdependence between the reformer heat exchange system and the turbine-generator system. As a consequence, use of surplus heat from the reformer heat exchange train to heat boiler feedwater, in a manner similar to that shown in GE's CR&D report, has not been included in the basic designs for Cases A, B, and C. Such

Table E-1

HEAT CYCLE EVALUATION DESIGN BASIS

Reformer System	
HTGR heat to reformer	515 MW
Reformer gas inlet temperature	824°F
Inlet pressure	220 psia
Outlet temperature	1100°F
Outlet pressure	147 psia
Reformer feed gas quantity	1.74×10^6 lb/hr
Reformer feed composition, % mol.	
CH ₄	24.55
CO	0.0
CO ₂	0.30
H ₂	1.17
H ₂ O	73.98
Reformer product composition, % mol.	
CH ₄	5.27
CO	6.71
CO ₂	6.45
H ₂	45.90
H ₂ O	35.67
Steam generator system	
HTGR heat to steam generator	723 MW
Steam generator pressure	1800 psia
Steam generator temperature	1000°F

heat economics were, however, subsequently incorporated in the refinements to the selected basic design. In these basic designs, the heat exchange between the reformer feed and effluent assumes the use of mixed feed evaporators (MFE). In the MFE, a two-phased stream containing both liquid water and a gaseous phase (i.e., steam and process gas) is flowing on one or both sides of the heat exchanger. The MFE concept has not been incorporated into the refined version of the selected cycle (see Appendix II A).

Since the reformer and steam generator operating conditions were held constant in this comparison of cycle alternatives, the design effort centered on developing the heat and material balances for the reformer heat exchange train and for the turbine-generator plant. In this design effort, the reformer heat exchange cycle was conceptualized first, and the turbine-generator cycle was designed to match the needs of the reformer system. Descriptions for each of three cases evaluated follow.

Alternate Cases Evaluated

Case A — Thermally Driven Heat Cycle. The heat cycle diagram for the Case A design is shown in Figure E-1. In this design, the methane-water mixture fed to the reformer is heated by the following exchanger sequence:

- Heated with partially condensing reformed gas in a mixed feed evaporator
- Further heated by steam at two temperature levels in series exchangers
- Heated to reformer feed conditions by exchange with the reformer outlet gas mixture

The reformer outlet gas is cooled prior to compression for pipeline transmission by the following exchange sequence:

- Cooled initially in the reformer feed-product exchanger
- Further cooled in the MFE with a vaporizing methane-water mixture

- Cooled ahead of compression by exchange with cooling tower water

The two pressure levels of steam which provide heat for the cycle are exhausts from the high and intermediate pressure turbines.

Case B — Compression-Driven Heat Cycle. A heat cycle diagram for Case B is shown in Figure E-2. In this heat cycle, the temperature of the reformed gas is maintained at a level above that of the methane-water mixture, with which it is being exchanged, by compression of the hot reformed gas. The compression not only adds heat to the gas mixture, but in increasing the pressure, it also raises the temperature of partial condensation of the water present. For this case the methane-water heating sequence is:

- Initial heating by exchange against the reformed gas in the MFE
- Further heating by exchange with the reformed gas in the hot gas compressor inter- and aftercoolers
- Final heating to reformer inlet temperature in the feed-product exchanger

The sequence for cooling the reformed gas is as follows:

- Initial cooling by exchange with the methane-water mixture in the feed-product exchanger
- Cooling to 380°F ahead of compression using cooling tower water
- Compressing the reformed gas from 137 to 535 psia and using the methane-water mixture for heat exchange in the compressor inter- and aftercoolers
- Cooling with feed methane-water mixture in the MFE
- Cooling to 120°F with cooling tower water

Figure E-1. Heat Cycle Diagram - Case A

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This heat cycle maximizes the heat exchange between the reformer gas and the methane-water mixture, but substantially increases the total amount of energy required for compressing the reformed gas to pipeline pressure (1200 psia).

Case C — Direct Steam Injection Heat Cycle. Figure E-3 shows the direct steam injection heat cycle, Case C. This cycle is similar to Case A, but the heat provided from the turbine-generator cycle is with direct steam injection rather than through an exchanger. The methane-water heating sequence for this case is:

- Initial exchange with the reformed gas in the MFE
- Direct injection of steam to further heat the methane-water mixture
- Heating to reformer inlet temperature by exchange with the reformed outlet gas

The cooling sequence for the reformed gas is:

- Initial exchange with methane-water mixture in the feed-product exchanger
- Further cooling by exchange with methane-water mixture in the MFE
- Cooling to 120°F with cooling tower water

The injection steam required for this case is exhaust from the high pressure turbine. Since condensate returned from the methanator and from the reformer train is sent to the turbine-generator plant, additional treatment of this condensate is provided before it passes to the steam generator.

Selected Cycle and Supporting Rationale

Heat cycle evaluation data for the three alternative designs were determined and tabulated to aid in making a rational selection of the preferred heat cycle. A summary of energy transfers and net electricity for export

for the three cases is presented in Table E-2. The amount of thermochemical energy in the syngas product is the same for each of the alternatives and amounts to approximately 560 MWt. Table E-3 shows the comparative equipment duties of the heat exchangers, compressors, cooling towers, and turbine-generators for the three cases. Table E-4 presents rough estimates of the capital differences developed for the three cases.

The results of the evaluations indicate that there is only marginal difference between the cases. The compression driven cycle (Case B) is slightly superior to Cases A and C in regard to net electrical power for export. Case A and Case C are nearly equivalent with respect to net power for export. Because of the costly hot gas compressors in Case B, it is the least attractive with regard to plant capital cost. Case C, the steam injection case, is slightly better than Case A with regard to plant capital cost, primarily due to the elimination of much heat exchange surface in heating reformer feed with steam injection. Case A is judged to have advantage over the other two cases with respect to controllability and safety. Case A is considered to have a significant advantage in safety over Case C because of a possible problem of tritium control in the process gas with direct steam injection.

In selecting the preferred basic heat cycle for the baseline plant design, seven evaluation factors, shown in Table E-5, were identified for rating the cycles. Importance weighting factors were assigned to each evaluation factor, and the rating was determined as the product of the ranking and the importance weighting factor.

With the aid of the tabulated heat cycle information, and consideration of the flexibility, controllability, and safety in plant operation for the alternative heat cycles, each of the three cases was rated. The results of this procedure, given in Table E-5, indicate that Case A, the thermally driven case, is slightly superior to Cases B and C.

Figure E-3. Heat Cycle Diagram – Case C

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Based on these results, the thermally driven heat cycle is recommended for the 850°C IDC baseline plant design.

Table E-2
ENERGY TRANSFER SUMMARY

	Case A	Case B	Case C
Heat Added to Feedstock (MWt)			
Feed-product exchangers	232	232	232 ⁽¹⁾
Methane-water heaters	239		250
Compressed gas cooler		84	
Mixed feed evaporators	119	274	108
Total	590	590	590
Heat Removed from Syngas (MWt)			
Feed-product exchanger	232	232	232
Mixed feed evaporators	119	274	108
Syngas cooler		31	
Compressed gas cooler		84	
Reformed gas cooler	207	50	218
Total	558	671 ⁽²⁾	558
Heat Rejected (MWt)			
Syngas cooling before compression	207	81	218
Main condenser	302	491	293
Pipeline gas cooler	84	30	84
Total	593	602	595
Net Electrical Power (MWe)			
Electricity generated	219	290	218
Electricity used			
Hot syngas compressor		125	
Pipeline compressor	100	35	100
Helium circulators	95	95	95
Other auxiliary power	15	15	15
Net power to export	9	20	8

(1) No heat exchanger required

(2) The total is larger than in Cases A and C because of heat input by the compressor

Table E-3
EQUIPMENT DUTY SUMMARY

	Case A	Case B	Case C
Heat exchanger duty (MWt)	1183	1192	935
Compressor duty (MW mech)	90	144	90
Cooling tower duty (MWt)	593	602	595
Turbine generator duty (MWe)	219	290	218

Table E-4
ROUGH ESTIMATE OF CAPITAL COST DIFFERENTIALS FROM CASE A

	Capital Differentials from Case A (\$ million)	
	Case B	Case C
Heat exchanger costs	0	-4
Compressor costs	+11	
Cooling tower costs	0	0
Turbine-generator costs	+4	0
BFW treating costs	0	+1
Total	+15	-3

Table E-5

HEAT CYCLE EVALUATION FACTORS FOR THE 850°C IDC HTGR-R PLANT

Heat Cycle Evaluation Factors	10 to 1 Importance Weight	Case A Thermally Driven		Case B Compressor Driven		Case C Direct Steam Injection	
		Ranking	Rating	Ranking	Rating	Ranking	Rating
Plant net output	10	9	90	10	100	9	90
Comparative capital cost (cost differentials from base case)	7	9	63	7	49	10	70
Ability to operate P/CP during T-6 trip	3	9	27	10	30	9	27
Ability to operate with one MHS loop down (short term)	3	9	27	10	30	9	27
Use of standard, commercially proven equipment: exceptions are listed on attached page	3	10	30	3	24	10	30
Overall operational reliability (passive versus rotating equipment)	7	9	63	7	49	10	70
Controllability/operational flexibility	3	10	40	8	32	9	36
Safety (tritium, etc.)	3	10	90	9	81	7	63
Summary of ratings			430		395		413

Each qualitative factor is assigned an importance weight on a scale of 10 to 1. For each case, a ranking of 1 to 10 is assigned. The rating is the importance weight x the ranking.

Appendix F

DESIGN DETAILS — 950°C DC REACTOR VESSEL

PCRV Structure. The PCRV structure for the 950°C direct cycle reforming plant is characterized by a central core cavity, surrounded by the following major cavities:

- Reformers (4, GE design)
- Steam Generators (2, GA design)
- Primary Circulators (2 above steam generator,
2 in separate cavities)

Provision has also been made in the PCRV for four cooling water header pits and two pressure relief pits. The main features of the PCRV are outlined in Table F-1, and the cavity envelopes used in the design are shown in Table F-2.

The primary coolant passes through the core on to the reformer and steam generator cavities in series and returns to the core cavity via the main circulators. The process heat lines come out of the top of the reformer cavity and are routed vertically downward through the PCRV and exit at the bottom. Both the superheat and feedwater lines of the steam generator cavity are located in the bottom of the PCRV. The necessary NHS and NSS/BOP interfacing connections have been identified. Plan and elevation views of the PCRV are given in Figure F-1 and F-2, respectively.

The PCRV dimensions are sized to layout considerations. The minimum circumferential ligaments between cavities and the space required for the linear prestressing tendons in the top head determined the outside diameter of the vessel. The height of the PCRV is dictated by the overall height

Table F-1

MAIN FEATURES OF PCRV FOR 950°C DC PLANT

PCRV concrete strength	6500 psi
LPS tendon strength (at GUTS)	2478 kips
CPS cable strength (at GUTS)	41.3 kips
Refueling scheme	In-vessel refueling (see memo #631:110:TFU:81 dated 4/29/81 for details of design)
Closures	
Reformer cavity	Shield plug flush with top of PCRV
Steam generator cavity (with main circulator on top)	Precast concrete prestressed ring
CAHE cavity	Steel dome
Main circulator cavity	Steel dome
Steam generator type	Once through bottom fed type
CAHE	Compact bayonet type

Table F-2

MAJOR PCRV PARAMETERS FOR 950°C DC PLANT

Type	Multi-cavity PCRV
Overall dimensions	
Diameter	108.00 ft
Height	92.00 ft
Core cavity, quantity	1
Diameter	31.5 ft
Height, including in-vessel refueling	68.14 ft
Reformer cavity, quantity	4
Diameter:	
Mid height	13.84 ft
Top	19.00 ft
Depth from top of PCRV	82.00 ft
Steam generator cavity, quantity	2
Diameter:	
Mid height	11.17 ft
Top	11.67 ft
Depth from top of PCRV	84.00 ft
Main circulator cavity, quantity	2
Diameter:	
Mid height	8.67 ft
Top	7.67 ft
Depth from top of PCRV	20.5 ft
CAHE cavity, quantity	3
Circulator cavity:	
Diameter:	
Mid height	6.67 ft
Top	8.83 ft
Depth from top of PCRV	21.33 ft
CAHE bundle cavity:	
Diameter:	
Mid height	6.00 ft
top	7.50 ft
Depth from bottom of PCRV	20.50 ft
Maximum cavity pressure	750 psig
PCRV support	Concrete ring support with center pedestal

required for the reformer component cavity. Maintaining the required head thicknesses, the core cavity height was extended by 8 feet in order to accommodate the core inlet duct from the main circulator cavities at an angle not greater than 30° to the horizontal. All the other major components, such as steam generators and main circulators, etc., were designed to fit within the available space of the PCRV height as established above. Because of the large and complex ducting on the primary and secondary side of the major components, the PCRV ligaments and the corresponding prestressing intensities have to be verified by analysis and suitable adjustments made to the PCRV size and prestressing as required. Provision has been made for all the secondary ducting to exit the PCRV vertically downwards to the bottom, and cutouts are shown in the PCRV support ring at these locations. The routing of these pipes from the underside of the PCRV is the responsibility of the architect-engineer.

PCRV Lines, Penetrations, and Closures. The steel cavity liners, penetrations, and penetration closures form the continuous gas-tight boundary of the PCRV. The liner and penetration anchors transmit loads from internal equipment support structures and axial loads from closure to the PCRV concrete. A liner cooling system is included to remove the heat transmitted through the thermal barrier before it reaches the concrete. The liners, penetrations, and closures are similar to those of recent HTGR-SC designs where similar components are housed. The HTGR-PH requires a new closure design for the steam generator cavity. This new closure is described below.

The top cap of the cavity liner is welded to the liner after the steam generator is installed. The prestressed concrete closure, containing a housing for the main circulator, is placed in position on the top of the PCRV, concentric with the cavity top cap. The bottom end of the circulator housing is welded to the liner top cap, forming a cavity between the top cap and closure. This cavity is filled with grout, through penetrations extending through the closure. The closure is retained with the PCRV vertical

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Figure F-2. PCRV Elevation View
F-7

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tendons. The reformer cavity configuration and its closures are dictated by reformer requirements. The design includes a dome closure which is recessed in the reformer cavity and is attached to a large ring forging, cast in the PCRV, and has a sleeve and flange that extends into the cavity. The reformer is retained with this flange. The axial load from the reformer is transmitted from the ring forging into the PCRV.

PCRV Thermal Barrier. The thermal barrier has been separated into a number of zones, according to service temperature and liner geometry considerations. Four different material selections have been made for the various zones according to hot surface temperature. The preliminary thermal barrier sizing calculations proceeded according to the following sequence:

- Thickness determination based on insulation properties. A factor of two times the thermal conductivity was used. Therefore the fibrous insulation thickness is approximately twice that which would result in the maximum liner overall temperature of 150°F.
- Thickness determination based on hot spot examination. The effect of attachment fixtures on thickness was determined in accordance with a maximum liner hot-spot temperature limit of 250°F.
- Final determination of thickness values based on the results of the above methods, plus any additional design factors.

The types of materials selected for the various thermal barrier components are shown in Table F-3. The materials were chosen on their ability to withstand the particular temperature environment. Using creep as a criterion, Type 316 stainless steel has been limited for use to 1150°F. The size of these cover plates (Figures F-3 and F-4) is governed by the acoustic environment, which is assumed similar to that of the steam cycle plant.

Hastelloy X was selected for the next higher temperature range thermal barrier. The basis for this selection is based on creep resistance and resistance to decarburization. Hastelloy X was also chosen for the seal sheet material because of its decarburization resistance.

Table F-3

THERMAL BARRIER MATERIAL SELECTION FOR 950°C DC PLANT

Cover Plate	Seal Sheet	Blocks	Pads	Insulation
Type 316 stainless steel	Type 316 stainless steel	—	—	Saffil + Kaowool
Hastelloy X	Hastelloy X	—	—	Saffil + Kaowool
Carbon/carbon	MA-956 (where required)	—	—	Saffil
Type 316 stainless steel	Type 316 stainless steel	Graphite	Pyrolytic graphite, alumina, fused silica	Saffil + Kaowool

Figure F-3. Thermal Barrier Coverplate With Integrated Attachment Fixture (Sheet 1 of 2)

Figure F-4. Thermal Barrier Coverplate With Integrated Attachment Fixture (Sheet 2 of 2)

The insulation blankets for the above two grades of thermal barrier consist of a composite of Saffil alumina HT and Kaowool. On the basis of resiliency, Kaowool is being limited to 900°F for long-time exposure.

The baseline material selected for the lower core cavity sidewall, reformer cavity, CAHE cavity, and the hot duct designs is carbon-carbon (C/C). The duct designs employ high temperature, high resilience insulation (Saffil) made in segments to form a washer fitted between a C/C inner shield and a conventional steel liner. The lower core cavity sidewall reformer cavity and lower CAHE cavity thermal barriers are, in general, similar to the metallic-fibrous classes of design employing coverplates and seal sheets but employing the different material selection. The Huntington oxide dispersion-strengthened alloy MA-956 was chosen as the seal sheet material because of its decarburization resistance.

The function of the bottom head thermal barrier is not only to protect the PCRV liner, but to provide a stabilized insulated structural base for the graphite core support posts. The configuration consists of layered polygonal graphite blocks with insulation blankets through which a series of ceramic support columns penetrate. These support columns consist of pads which are sized to accommodate mechanical loads transmitted through the support posts (including seismic conditions), as well as to act as insulators. The thermal loads dictate the thicknesses of the pads. Pyrolytic graphite is designated for the top pad. High purity (99.5%) alumina is designated for all the remaining pads, with the exception of the bottom pad, which is the final insulator. The material for the bottom pad is a high density, fine grain silica.

The polygonal blocks are exposed to the direct gas stream and, hence, the highest core outlet temperatures. Here the main problem is to dissipate the gas streaks, thereby minimizing the thermal shock imparted to the substrate layers.

APPENDIX G

Appendix G

DESIGN DETAILS — 950°C DC STEAM GENERATOR

The steam generator assembly (shown in Figure G-1) consists of a single helically coiled tube bundle which is made up of 195 continuous tubes. Each tube is fabricated of three different materials with four different wall thicknesses, but with a common outside diameter. The unit is built to ASME B and PV Code Section III, Class 1 and high temperature Code Case N-47.

The all-helical tube bundle is proposed to take advantage of the fact that the inlet helium is discharged from the top of the reformer cavity prior to entering the steam generator cavity. Thus, the gas can conveniently enter the steam generator at the top, flow down across the tube bundle, and discharge at the bottom.

Feedwater enters the unit through a tubesheet located at the bottom and flows up through riser tubes to the tube bundle, through the tubes to the top of the bundle, through expansion loops to downcomers located in the center of the bundle, and then down to the superheater tubesheet. Primary dimensions and flow characteristics are shown in Table G-1.

This steam generator differs from the MK IV-A concept in that the helium makes a single top to bottom pass over the bundle. In the MK IV-A, the gas enters at the bottom, rises over the "high" temperature straight tube superheater, turns and flows downward over the "low" temperature helical bundles of the first superheater, the evaporator, and the economizer. The two bundle sections are joined by bimetallic welds (BMWs) located in a quiescent helium zone.

Table G-1

DETAILS OF STEAM GENERATOR FOR 950°C DC PLANT

Number of units/plants	2	
Unit thermal rating	281 MWt	
Unit OD	119.5 in	
Overall length	45.2 ft	
Number of tubes	195	
Tube size	1 in OD x 0.14/0.08/0.13/0.11 x 170 ft long	
Design conditions:		
	<u>Inlet</u>	<u>Outlet</u>
Helium temperature	1278°F	894°F
Helium pressure	668 psi	658 psi
Helium flow rate	2.03×10^6 lb/hr	
Water/steam temperature	500°F	1050°F
Water/steam pressure	2900 psia	2400 psia
Water flow rate	9.5×10^5 lb/hr

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The basic problem with the location of the BMW is to place it in a section of the bundle where the metal temperature does not exceed that of the low temperature materials' capability and yet in a region where dry steam is present so that the austenitic material (Inconel 800H), which is subject to stress corrosion, will not be wetted.

In this design, it is proposed to use Inconel 800H in most of the superheater section and switch to Inconel 800 at the 50°F superheat point. Inconel 800 has shown greater resistance to stress corrosion than has Inconel 800H. This material would be carried down into the evaporator section until it is joined with the lower temperature 2-1/4 Cr — 1 Mo which is used in the rest of the evaporator and the economizer section.

It should be noted that Alloy 800 is in Section VIII, Div. 1 at the elevated temperatures of interest. An additional effort would be required to get it into the Section III, Class 1 Code Case.

APPENDIX H

Appendix H

DESIGN DETAILS — DIRECT AND INDIRECT CYCLE REFORMERS

Figures H-1 and H-2 shows the conceptual designs of the 950°C DC reformer and the 850°C IDC reformer, respectively. Since there is a commonality in the basic configuration of the two reformers, the common features are described and the unique characteristics of each reformer design are indicated explicitly.

Design Description. For both the 950°C and 850°C reformers, hot helium enters the lower inlet plenum and flows upwards on the shell side of the reforming tubes in a serpentine pattern. A serpentine flow pattern is achieved by installing baffles spaced axially along the tubes. The helium exits the reformers below the support plate and flows downward through the inner flow shroud and into the exit nozzle. The heat required for the 950°C DC reformer is supplied by the primary helium. The 850°C IDC reformer uses the heat from the secondary helium which circulates through the intermediate heat exchanger (IHx).

The process gas is introduced into the upper plenum, as shown in Figure H-3, for both the 950°C and 850°C reformers. The gas flows between the tubesheet and the support plate and enters the catalyst-filled reforming tubes, where the reforming process takes place. After flowing downward to the bottom of the tube, the reformed gas enters the internal pigtail tube. The pigtail tube acts both as a return tube and as a secondary heat regeneration for the incoming process gas. Finally, the gas is discharged into the outlet plenum above the support plate and exits the reformers.

Figure H-1. Conceptual Design for Steam Reformer —
950°C Direct Cycle Reforming Plant

Figure H-2. Conceptual Design for Steam Reformer —
850°C Indirect Cycle Reforming Plant

Figure H-3. Upper Plenum Region for Steam Reformer —
950°C DC and 850°C IDC Reforming Plants

The tubesheet is used to suspend the catalyst-filled reforming tubes. Since the tubesheet is a boundary between the process gas and the incoming hot helium, it will be exposed to the most severe transient conditions. Consequently, the tubesheet is quite large and complex. In contrast, the support plate is used only to support the process gas pigtail tubes and is exposed to the outgoing helium of a lower temperature. The support plate is designed to be easily removed from the vessel in order to perform maintenance and repair operations. The reforming tube diameter is reduced at the upper end to permit a reasonable tubesheet integrity without excessive tube spacing.

Reformer Tube Bundle. The primary configurational difference between the DC and IDC reformers is the reforming tube itself. For the 950°C DC application, a duplex tube design is selected, because it provides a double physical barrier between the radioactive primary helium and the non-radioactive process gas and a means to monitor the tubes for leaks. The 850°C IDC reformer uses a single-walled reforming tube. The construction of the individual reformer tube is shown schematically in Figures H-4 and H-5. The catalyst-filled reforming tube is suspended vertically from the tubesheet. A pigtail tube for process gas return is suspended within the reforming tube by the support plate. Both tubes are allowed to expand axially but are restrained horizontally by baffles spaced axially along the reformer tubes. Each reformer tube is welded to the tubesheet. The outer tube of the 950°C duplex reforming tube is welded directly to the bottom of the tubesheet. The inner tube of the duplex tube extends through the tubesheet and is welded to the upper surface of the tubesheet. The internal pigtail extends upward into the process gas outlet plenum and is attached to a clamp and seal assembly located on top of the support plate. The 950°C duplex tube is formed in two walls separated by a buffer gas gap. This gap is about 0.2 mm wide and allows for the option of releasing fission gas and tritium to a buffer gas system.

Figure H-4. Duplex Reforming Tube for 950°C DC

Figure H-5. Single Walled Reforming Tube for 850°C IDC

Operational Conditions. The specific difference between the two reformers results from the higher reforming temperatures in the 950°C DC. Tables H-1 and H-2 show the steam reformer design data for the 950°C DC and the 850°C IDC.

For the 950°C DC reforming plant, there are four steam reformers in the plant. One steam reformer of thermal duty of 163.5 MWt is provided for each one of the four independent primary helium loops. Each reformer is located inside a cavity in the PCRV which is within the reactor containment building. During normal plant operation, primary helium of 125.6 kg/sec enters each reformer at 947°C and exits at 696°C, and process gas of 69.6 kg/sec at a steam/methane ratio of 2.5 enters each reformer at 538°C and exits at 631°C. Process gas pressure (49 bars) is slightly higher than the primary helium pressure to prevent process gas contamination in the event of a reformer tube leak. Using 86 mm O.D. duplex tubes with 12.5 m active length, a total of 1400 tubes and a bundle diameter of 3.7 m are required for each reformer. A methane conversion of 60% can be achieved. Because the reforming tubes act as the primary coolant boundary and can also be used for leak detection, the design of the 950°C DC reformer conforms to the requirements of the ASME Code Section III, Class 1 component. Due to the high temperature/pressure environment in the 950°C DC reformer, material selection is a critical design consideration. Preliminary stress analysis indicates that Inconel 617 or a similar material is required for the reforming tubes, tubesheet, and the shroud.

Because of the lower helium inlet temperature, the reforming efficiency of the 850°C IDC reformer is reduced. Two steam reformers are required for each of the four secondary helium loops to provide an acceptable bundle diameter for shipment by the conventional rail. The design of the 850°C IDC reformer is greatly simplified over the 950°C DC reformer, due to the physical location and temperature/pressure environment. In the

Table H-1

STEAM REFORMER DESIGN DATA
950°C DIRECT CYCLE REFORMING PLANT

Number of steam reformers in plant	4
Thermal duty per module, MWt	163.5
Primary helium conditions:	
Mass flow, kg/sec.	125.6
Inlet temperature, °C	947
Outlet temperature, °C	696
Inlet pressure, bar	47.0
Outlet pressure, bar	46.3
Process gas conditions:	
Mass flow, kg/sec.	69.6
Steam/methane ratio	2.5
Inlet temperature, °C	538
Outlet temperature, °C	631
Inlet pressure, bar	49
Outlet pressure, bar	44
Maximum reforming temperature, °C	844
Methane conversion, %	60
Reforming tube dimensions:	
Outer tube O.D., mm	86.0
Outer tube I.D., mm	73.7
Inner tube O.D., mm	73.3
Inner tube I.D., mm	61.3
Active length, m	12.5
Number of tubes	1400
Pitch factor	1.18
Pigtail:	
O.D., mm	20
I.D., mm	18
Catalyst:	
O.D., mm	6.7
I.D./O.D., %	62
Length, mm	6.7
Life, years	7-10
Baffled regions	3
Bundle diameter, m	3.7
Design life, years	40
ASME code classification	Section III, Class 1
Seismic category	I

Table H-1 (Cont'd)

Material of construction:	
Reforming tubes	Inconel 617
Upper tubesheet	Incoloy 800H
Lower tubesheet	Inconel 617
Shroud	Inconel 617
Vessel head	SS 316
Cover plate	SS 316

Table H-2

STEAM REFORMER DESIGN DATA
850°C INDIRECT CYCLE REFORMING PLANT

Number of steam reformers in plant	8
Thermal duty per module, MWt	65.5
Primary helium conditions:	
Mass flow, kg/sec.	64.3
Inlet temperature, °C	791
Outlet temperature, °C	595
Inlet pressure, bar	48.7
Outlet pressure, bar	48.3
Process gas conditions:	
Mass flow, kg/sec.	39.0
Steam/methane ratio	4.0
Inlet temperature, °C	450
Outlet temperature, °C	562
Inlet pressure, bar	25
Outlet pressure, bar	20
Maximum reforming temperature, °C	727
Methane conversion, %	60
Reforming tube dimensions:	
O.D., mm	107.5
I.D., mm	76.7
Active length, m	12.5
Number of tubes	533
Pitch factor	1.18
Pigtail:	
O.D., mm	25.0
I.D., mm	22.3
Catalyst:	
O.D., mm	8.3
I.D./O.D., %	62
Length, mm	8.3
Life, years	7-10
Baffled regions	4
Bundle diameter, m	3.3
Design life, years	40
ASME code classification	Section III, Class 2
Seismic category	II

Table H-2 (Cont'd)

Material of construction:	
Reforming tubes	Incoloy 800H
Upper tubesheet	Incoloy 800H
Lower tubesheet	Inconel 617
Shroud	Incoloy 800H
Vessel head	SS 316
Cover plate	SS 316

850°C IDC reforming plant, since the IHX constitutes the primary coolant boundary and the steam reformer is located in the secondary coolant loop, the reformer is designed as an ASME Code Section III, Class 2 component, which is not so stringent as that of the 950°C DC reformer. Two 850°C IDC reformers are contained in a single prestressed concrete pressure vessel (PCPV) which is housed in a reformer building. The four reformer buildings in the plant are located outside the reactor containment building. Each of the eight 850°C IDC reformers has a thermal duty of 65.5 MWt. Reforming tubes are of 107.5 mm O.D., single-walled, and 12.5 m active length. A total of 533 tubes is required for each reformer. During normal plant operation, secondary helium of 64.3 kg/sec enters each reformer at 791°C and exits at 595°C, and process gas of 39 kg/sec at a steam/methane ratio of 4.0 enters each reformer at 450°C and exits at 562°C. Helium pressure is 49 bars, and process gas pressure is 25 bars. A methane conversion of 60% can be achieved. Due to the lower helium inlet temperature (790°C) of the 850°C IDC reformer, a less expensive material, Incoloy 800H, can be used for the reforming tubes.

Catalyst replacement can be accomplished by two methods. In the first method, each tube is handled individually. The reformer head and the process gas outlet plenum cover plate are covered. Each straight pigtail is then removed individually and the catalyst vacuumed out. The tube is then inspected, refilled, and tested for uniform catalyst loading by measuring the pressure drop through the tube. The second method entails having the pigtail tubes attached to the upper tubesheet and pulling all tubes at once. The catalyst replacement can then proceed the same as individual tubes.

If tube plugging is required, the pigtail is removed and an end cap is inserted and welded into the upper end of the reformer tube. A plug replaces the pigtail and is welded in place.

APPENDIX I

Appendix I

DESIGN DETAILS — METHANATION PLANT

The process flow diagram for the 40 MWt methanation plant, Figure I-1, shows the syngas being received from the HTGR-R via the TCP. The syngas contains 5 ppmv sulfur in the form of 50% butylmercaptan and 50% demethylsulfide added as an odorant to provide leak detection capability. Prior to methanation the total sulfur content of the reformed gas must be reduced to less than 0.1 ppmv to prevent sulfur poisoning of the methanation catalyst.

The desulfurized syngas then flows through a fixed-bed combination methanator/evaporator (isothermal process) followed by two fixed-bed adiabatic catalytic reactors. Between reactors, exothermic heat of reaction is removed from the system by the generation of high pressure steam and by feed-effluent exchanged in conventional heat exchangers. As the flow progresses through the reactors and heat exchangers, the bulk of the syngas is methanated. The temperature of the process gas is progressively lowered, finally resulting in a reduced temperature favorable for achieving a high conversion of hydrogen and carbon oxides to methane.

The methane gas from this plant is returned to the HTGR-R plant via the return leg of the TCP. The condensate generated by converting syngas to methane may be returned to the HTGR-R plant via a pipeline, or it may be used as a feedwater for steam generated at the methanation plant.

Methanation. In the methanation of syngas mixtures, these chemical equations represent the net reactions taking place:

- Water-gas shift:

- Carbon monoxide methanation:

- Carbon dioxide methanation:

The water-gas shift (Eq. 1) takes place rapidly and is essentially in thermodynamic equilibrium. In syngas mixtures, the carbon monoxide reaction (Eq. 2) dominates. Only when carbon monoxide depletes to ppm levels does carbon dioxide methanation (Eq. 3) take place. The reactions are catalyzed by various metals. Nickel-on-alumina is the most commonly used, commercially.

The rates of conversion and heat generation in a catalytic methanation process are determined by the rate of reaction at the catalyst sites and the rates of mass and heat transport in the gas and in the catalyst pores. To predict accurately the process temperature changes, bulk conversions, and catalyst volume required, the methanation model used in designing the process takes into account the reaction paths and factors in the contributions of the following reaction parameters:

- Catalyst activity in terms of active metal sites per gram of catalyst
- Mass transfer rates of reacting gases through the gas and through the catalyst pores
- Temperature differences between gas and catalyst particles
- Reaction rates at the metal sites based on experimentally determined kinetics

Figure I-1. Process Flow Diagram,
40 MWt Methanation Plant

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Methanation Catalysts. At the core of the methanation process is the methanation catalyst that promotes the exothermic methanation and water-gas shift reactions. The reactions are catalyzed by a number of transition metals, the more active ones being Ni, Ru, Pd, Co, Fe, Mo, Pt and Rh. The metal is dispersed on a porous support such as alumina, silica, or magnesia to increase the amount of metal sites available for catalysis and to reduce metal agglomeration during reaction. At present, essentially all methanation catalysts employ Ni as the active metal, with alumina being the preferred support. Catalyst specifications for the methanation in the GE-ARSD process are listed in Table I-1. The catalyst is manufactured as nickel oxide on alumina. It is activated prior to use by reduction of the nickel oxide to nickel in a reducing gas mixture of from 20 to 100 percent hydrogen.

Combination Methanator/Evaporator. The combination methanator/evaporator (C M/E) shown in Figure I-2 consists of catalyst-filled tubes with water flow between the tubes and the pressure vessel wall. This isothermal process was chosen for the following reasons:

- Combining the first methanator with the evaporator eliminates the evaporator as a separate heat exchanger and hence reduces cost.
- The use of water as a coolant helps control the temperature of the process gas within the desired limits.
- By limiting the temperature of the C M/E to 1015°F maximum, the tubes, tubesheets, vessel, and vessel ends can be fabricated of ASME-approved materials.
- The need for internal refractory insulation as normally used for high temperature adiabatic methanators is eliminated. This is also a cost savings.

The C M/E consists of 336 stainless steel tubes 4.00 inches O.D. (3.62 inches I.D.) x 270 inches long. The bottom tubesheet is secured to the pressure vessel, while the top tubesheet is free to float with temperature changes. The catalyst is supported by a perforated metal cone in each tube. It is

Table I-1.

CATALYST SPECIFICATIONS FOR THE GE-ARSD PROCESS

	Methanator 1	Methanators 2 and 3
Form	Tablet	Tablet
Size, in.	0.25 x 0.25	0.25 x 0.25
Temperature range, °F	600 - 1200	450 - 850
Pressure range, psig	up to 1500	up to 1500
Composition (dry), wt%		
NiO	32	75
Al ₂ O ₃	62	22
Others	6	3
Bulk density, Pf ³	60	58
Surface area (BET), m ² /g	110	225
Pore volume, cc/g	0.25 - 0.45	0.45 - 0.55
Crush strength, psi	> 700	> 500

Figure I-2. Combination Methator/Evaporator

estimated that the life of the catalyst will be 2.5-3 years. The vessel is 8'-0" I.D. x 34'-8" high, with a wall thickness of 4 inches. The body of the vessel is designated for 550°F, the bottom end for 650°F, the top end for 1015°F, and all parts for a pressure of 900 psia.

Adiabatic Methanator. Two adiabatic methanators, shown in Figure I-3. and located in series, are used for final conversion of syngas to methane and for polishing the methane prior to cooling it for return to the HTGR reforming plant. The temperatures of these methanators are from 550°F to 650°F so that internal refractory insulation is not required. The adiabatic methanator vessels are 8'-0" I.D. x 18'-1" high, with a wall thickness to 4 inches. The vessels are designed for a pressure of 900 psia.

Both adiabatic methanators have packed beds of catalyst supported on a monolithic ceramic grate. Personways are located in the top and in the side, near the bottom of the catalyst bed, for loading and unloading the catalyst. It is anticipated that the life of the catalyst in these two methanators will be 5 years.

Figure I-3. Adiabatic Methanator

Appendix J

THERMOCHEMICAL PIPELINE — PROCESS CONSIDERATIONS

The optimum values for the operating parameters of the thermochemical pipeline (TCP) system from the reforming plant through the pipeline to the methanation plant and back to the reforming plant must be selected by comparing the interrelationships of the various parameters and their effects on the reforming and methanation processes. The groundrules of a 60% methane conversion and a maximum amount of thermochemical energy to the pipeline within the limitation of no imported power were considered a sound basis for comparing the plant options (950°C DC and 850°C IDC), based on previous evaluations. These groundrules established a compromise that was judged to be close to optimum for comparing the plant options while simultaneously reducing the iterative interface requirements in designing the reformer-methanator loop so that the design of the reformer plant, pipeline, and the methanator plant could proceed independently.

The principal parameters that define the optimum reformer plant design conditions are methane conversion level, reforming pressure, steam/methane ratio, reformer helium outlet temperature, and power split between the reformer and the steam generator. The methanation plant is also affected by temperature, pressure, methane conversion, and steam/hydrogen ratio. Similarly, gas transmission costs (pipeline cost plus compression cost) are a function of the conversion level in both reforming and methanation steps and of the operating pressure for each. In short, the TCP system parameters have to be considered in order to select the most cost-effective components, to determine the pipeline operating pressure for driving the methanation plant, and to minimize the power required to run the system. The TCP system computer code (TCP 1) was used to evaluate the interrelationships of

the principal system parameters. The operating parameters for the TCP system were then chosen from these relationships within the groundrules selected for the various plant options, as shown on the flowsheets for the 850°C IDC and the 950°C DC cases. Appendixes H and I illustrate some of the calculational details for the reformer and methanator, respectively.

Evaluation of Reforming Plant Parameters. For a given reformer tube design and catalyst formulation, the key operating factors that determine reformer conversion are the helium stream inlet conditions and the reformer feed inlet conditions. The helium inlet stream dictates the achievable temperature profile in the catalyst bed in each reformer tube. This temperature profile sets the reaction rate at the catalyst particles. At a given reacting temperature, a high steam/methane stoichiometry in the process gas enhances conversion while a high process gas pressure reduces conversion. Even though the higher steam/methane ratio stimulates the reforming activity and reduces the reformer size, the requirement of boiling more feedwater for the reforming process results in a reduction of the overall plant cycle efficiency.

For the first part of the process considerations, the reformer tube configuration assumed was for the 950°C DC design. The helium stream temperature at the reformer shell inlet was varied between 850°C to 950°C to determine the corresponding change in process gas flow rate and reformer conversion. The methanation plant yield was set to give about 95% methane in dry feed to reformer. The reformer process gas pressure was maintained at the design value of about 680 psia. The TCP 1 code was used to simulate the reformer conversion at helium inlet temperatures of 850°C, 900°C and 950°C, respectively. TCP 1 calculates conversion assuming equilibrium at the process gas pressure and temperature at the exit of the reformer tube. In actual operation, of course, equilibrium is closely approached, but never quite reached.

To obtain the points at a conversion level of 50%, 60%, 70%, or 80% at each temperature, the steam/methane ratio in the feed was varied until the desired

conversion was reached. As shown in Figure J-1, the increased process gas flow rates at the higher conversions and lower temperatures is a direct result of the increase in steam/methane ratio. Figure J-2 shows the negative effect on conversion of lower reforming temperature as a result of decreasing the helium inlet temperature if no adjustment is made in the steam/methane ratio to compensate. Table J-1 summarizes the conditions used in the TCP 1 simulations corresponding to the points plotted in Figures J-1 and J-2.

Table J-1

SUMMARY OF PROCESS CONDITIONS USED IN TCP 1

Helium Inlet Temperature (°C)	Bottom of Reformer Tube		Steam/Methane Ratio in Feed for			
	Temperature (°C)	Pressure (psia)	50% Conversion	60% Conversion	70% Conversion	80% Conversion
850	764	656	3.21	4.88	6.10	8.29
900	808	656	2.26	3.50	4.44	6.10
950	851	656	1.57	2.50	3.19	4.49

For the second part of the process considerations, several reforming and methanation conditions were simulated in TCP 1 in order to relate the behavior of conversion and dry product yield to:

- Temperature
- Pressure
- Amount of steam in feed

Figure J-3 shows the reforming methane conversion as influenced by process gas temperature, pressure, and steam/methane ratio in feed. Higher conversions are achieved at higher temperatures and steam/methane ratios, and at lower pressures. Figure J-4 presents the results in Figure J-3 in terms of methane composition in the reformer product stream.

Figure J-1. Helium Inlet Temperature Effect on Process Gas Flow Rate

Figure J-2. Helium Inlet Temperature Versus Reforming Conversion at S/C Ratio of 2.5/1

Figure J-3. Equilibrium Methane Conversion in Reformer (as % Conversion)

Figure J-4. Equilibrium Methane Composition in Reformer (as % Dry Product)

Evaluation of Methanation Plant Parameters. For the third part of the process considerations, methanation conversions were simulated in TCP 1 at various equilibrium temperatures and pressures. A dry methanator feed was used in practically all cases. The dry feed makeup is similar to feed from a reformer operating at a 60% conversion. Figure J-5 shows the results of the simulations. Plots 1 and 3, when compared to Plot 6, show that diluting the feed with steam reduces the achievable conversion for a given temperature and pressure of the process gas. For a specified process temperature and feed makeup, increasing the pressure will improve achievable conversion. The number of methanation steps required to achieve a conversion of approximately 98% will be largely determined by the design of the methanator vessel and catalyst bed.

Figure J-6 compares three methanation process alternatives to illustrate how methanator vessel design determines the number of methanation steps. In all three alternatives, the dry syngas feed had 9.9 mole% CO, 9.5 mole% CO₂, and 12.9 mole% CH₄. Process A is a typical adiabatic process without an in-vessel temperature control system. Six steps are required in this process to achieve a 98% conversion. This process has the advantage of reaching effluent temperatures well over 800°C in the first methanator. Process B employs active in-vessel temperature control. Product recycle (Alternative 1) or internal cooling (Alternative 2) is used to slow down the process temperature rise. As Figure J-5 shows, a moderate-to-slow climb in process temperature results in a lower equilibrium (or effluent) temperature but a higher conversion in a single step. As a result, only three methanation steps are required in Process B to achieve 98% conversion. Process B requires fewer components to achieve the same conversion as Process A.

Figure J-5. Methane Equilibrium Conversion Versus Temperature and Pressure

Process A

Process B

Figure J-6. Methanation Process Alternatives

APPENDIX K

Appendix K

METHODOLOGY FOR SCREENING CANDIDATE SYNFUEL PROCESSES

The criteria and weighting factors which were used in this second screening process are shown in Table K-1. The list of assumptions is shown in Table K-2. Each process was ranked on a scale of 10 for each criterion. That ranking was then multiplied by the corresponding weighting factor. The total rating for each process was the sum of the weighted ratings for all criteria.

Additional data were collected from each of the sixteen remaining processes. The data collected included the amount of high temperature ($>900^{\circ}\text{F}$) heat needed by the process and the temperature levels for these requirements. In addition, data were collected on the quantity of steam and electricity needed to be imported to the process. The electrical energy requirements, in megawatts electrical, were multiplied by three to convert them to megawatts thermal. A summary of the data collected for all sixteen processes is presented in Table K-3.

Representatives from all four of the participating organizations then ranked all of the processes. The results are summarized in Table K-4. As can be seen, the ratings by the four participants are usually similar and consistent.

For the purpose of the present study, it was intended to take at least one process for each class of product; however, syngas simply did not look like a good application, and no syngas process was selected. The processes which were selected for evaluation at this time are two shale processes (Paraho and TOSCO II), a transportation fuel process (SRC-II), and an SNG process (Exxon catalytic coal gasification). The rationale for selection of these processes is clear from Table K-4. Where a pair of similar processes is judged equivalent, the process which was selected is the one about which more is known.

Table K-1

CRITERIA AND WEIGHTING FACTORS USED IN PROCESS SCREENING

Criterion	Importance Weighting Factor
Quantity of high temperature heat	2
Quantity of steam	2
Quantity of electricity	1
Ease of coupling	2
Developmental status	1
Availability of process data	3
Reductions in emissions	1
Safety considerations	1
Economic considerations	1
Thermal efficiency	2
Market penetration	2

Table K-2
LIST OF ASSUMPTIONS

- Scope is limited to applications in the U.S.
- Coal and oil shale are the feedstocks to be considered
- Plant capacity assumed to be 50,000 b/d oil equivalent product
- Products for the various categories are as follows:

Coal gasification

Marketable SNG and syngas

Coal Liquefaction – direct

Acceptable refinery feedstock and transportation fuel

Coal Liquefaction – indirect

Transportation fuel

Oil shale retorting

Acceptable refinery feedstock

Advanced processes

Not to be considered in the current screening effort

Table K-3

SUMMARY OF ENERGY REQUIREMENTS FOR CANDIDATE PROCESSES

Product	Process	Process Thermal Efficiency (Approx.)	Process Energy Needs in MW _e (1)						Remarks
			High Temp. Heat			Process Steam	Electrical: MW _e = 3 x MW _e	Total	
			1400°F-1600°F	1200°F-1400°F	900°F-1200°F				
Syncrude (oil shale)	Union-B	70	168 ⁽²⁾		484		345	997	Shale oil upgrade
	Paraho	70	145 ⁽²⁾		390	140	340	1015	Shale oil upgrade
	Tosco-II	70	185 ⁽²⁾	583	54	27	300	1149	Shale oil upgrade
	Hytort	60		670			710	1380	For eastern oil shale
Transportation fuels	H-Coal	60			305	680	1120	2105	Energy for high ash coal
	SRC-II	65	250 ⁽²⁾		300	535	15	1140	
	Texaco and Mobil-M	50			296		770	1066	
	Lurgi and Mobil-M	55				243	1250	1493	
SNG	Exxon Catalytic	65	50	70	60	1130	540	1850	SNG could be converted to syngas by reforming
	Winkler	50			136	800	590	1526	
	Lurgi 100 Bar	—	No data available						
Syngas	Texaco	65			237		249	486	
	Koppers-Totzek	55			118		1230	1348	
	Lurgi Slagging	70				194	705	899	
	U-Gas	75			188			188	
	Westinghouse	75		87	53			140	

(1) Based on plant capacity of 50,000 b/d oil equivalent

(2) For methane reformer. Heat requirements can be lowered to 1200-1400°F level with lower process efficiency

Table K-4
PROCESS SCREENING SUMMARY

Product	Process	Application Ratings by Group Participants				Group Average Rating	Remarks
		Participant A	Participant B	Participant C	Participant D		
Syncrude	Union-B Paraho	107	121	127	115	118	Processes are equivalent; neither handles shale fines
		107	127	130	110	119	
	Tosco-II	109	98	134	117	115	Handles shale fines but more complex system
	Hytort	98	101	115	106	105	For eastern shale and not near term development
Transportation fuels	H-Coal SRC-II	115	122	118	127	121	Processes are equivalent; more public data believed available on SRC-II
		98	137	120	123	120	
	Texaco and Mobil-M Lurgi and Mobil-M	88	120	123	80	103	Indirect liquefaction is less attractive than the above direct liquefaction processes
		92	113	123	89	104	
SNG	Exxon Catalytic Winkler	115	130	125	94	116	Recommended for SNG
		102	112	118	83	104	
Syngas	Texaco	82	99	94	72	87	Syngas does not appear to be as good an application as the other three product areas shown above, which are essentially equivalent
	Koppers-Totzek	89	102	117	68	94	
	Lurgi Slagging	109	106	108	53	94	
	U-Gas	60	90	NR	54	68	
	Westinghouse	51	81	80	57	67	

Appendix L

PROCESS DESCRIPTION EXXON CATALYTIC COAL GASIFICATION (ECCG)

An Exxon study design (Reference 1) of a plant to produce 254 million standard cubic feet per day (scfd) of syngas from mine mouth Illinois No. 6 coal has been used as a basis for the HTGR/ECCG evaluation. Coal is fed at a rate of 14,500 tons per day (t/d) to integrated coal crushing/drying systems. The coal is crushed to minus 8 mesh size and dried to 4 wt% moisture in entrained bed dryers, using 900°F carrier gas. Catalyst solution, consisting of a mixture of potassium salts in water, is added to the dried coal, and the coal is dried again in a similar manner. An additional 700 t/d of coal is used as fuel in the two drying steps.

The coal-catalyst mixture is pressurized to 545 psia in lock-hopper systems with recycle synthesis gas. Coal particles are conveyed pneumatically from the pressurized vessel using partially heated 800°F recycle gas as the conveying medium. The catalyzed coal particles in the gasifier are fluidized with a preheated mixture of steam and recycled CO and H₂ injected into the gasifier through distributors. The main reactions taking place in the gasifier are the highly endothermic steam/carbon gasification reaction ($\text{CO} + \text{H}_2\text{O} = \text{CO} + \text{H}_2$), the mildly exothermic water-gas shift reaction ($\text{CO} + \text{H}_2\text{O} = \text{CO}_2 + \text{H}_2$), and the highly exothermic methanation reaction ($\text{CO} + 3\text{H}_2 = \text{CH}_4 + \text{H}_2\text{O}$). The top section of the gasifier contains a solids disengagement zone and two external cyclones in series to minimize fines carryover. At the bottom of the gasifier, a char solids stream is withdrawn to control bed level and ash buildup. This char stream is cooled with recycle synthesis gas and process water. It is then slurried with a semi-rich catalyst solution for feed to catalyst

recovery. The steam/recycle gas mixture is heated to outlet conditions of 1550°F and 520 psia in the preheat furnace.

The high level sensible heat in the effluent gas is recovered and used for preheating the steam/recycle gas and for generating high pressure steam. Exchanger fouling is not a problem, since heavy hydrocarbons are present in only trace concentrations at the gasifier exit temperature of 1275°F and in the presence of the potassium catalyst. Fine solids remaining in the gas leaving the high pressure waste heat boilers are removed in a two stage water scrubbing system consisting of spray saturator towers and venturi scrubbers. The solids-free scrubbed gas is further cooled in low pressure waste heat boilers.

A heavy glycol solvent absorption process removes H_2S and CO_2 from the gasifier product gas. The resulting clean gas consists primarily of CH_4 , CO , and H_2 , along with some N_2 . In the methane recovery system, cryogenic fractionation is used to split this stream into a product CH_4 stream and a recycle stream. The product methane stream from the tower bottoms is 99.9% CH_4 and 0.1% CO . Small amounts of this stream are withdrawn for use as plant fuel and methane refrigerant makeup. The remainder, the product SNG, is compressed to 1000 psig for delivery to a natural gas pipeline. The tower overhead stream, containing CO , H_2 , N_2 , and 10% CH_4 , is compressed for recycle to the reactor system.

The slurry of char/ash solids withdrawn from the gasifiers and the slurry of fine gasifier solids from the water scrubbing system are fed to the catalyst recovery section. The two streams are depressured into $Ca(OH)_2$ digestion vessels. Feed lime (CaO) and makeup potassium in the form of a 30 wt% KOH solution are also fed into these vessels. About 90% of the potassium in the feed solids is solubilized, and about 98.5% of the potassium salts so solubilized is recovered in the subsequent multistage water washing facility. Overall, this section recovers 87% of the total potassium catalyst which entered the gasifiers with the feed coal.

The offsite facilities for the ECCG plant include materials handling equipment to:

- Receive, store, and distribute coal, makeup catalyst, and lime
- Store and ship byproducts
- Handle and store waste solids and truck them to a nearby disposal site

A full range of utilities systems is provided, including raw water supply, water treating, steam generation and distribution, flue gas desulfurization, cooling water, and electric power distribution. The general offsites area encompasses wastewater treating, safety and fire protection systems, buildings, and miscellaneous items such as maintenance and mobile equipment, communications, and others.

APPENDIX M

Project Technical Requirements

PTR- 4.0		Page <u>1</u> of <u>27</u>	
Title FUNCTIONAL SPECIFICATION - HTGR-PH REFERENCE PLANT			
APPROVAL RECORD			
Rev. No.	Approval Date	Approved By	Concurred By
		General Manager	

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1.0 PURPOSE

This specification delineates functional requirements and objectives governing the design and development of a Reference Commercial High Temperature Gas-Cooled Reactor-Process Heat (HTGR-PH) plant. It is intended to be the first embodiment of a plant specification which will ensure the uniform application of the stated criteria to all design agents so that the plant characteristics will conform to the functional requirements of Gas-Cooled Reactor Associates (GCRA), while complying fully with applicable regulatory requirements.

The HTGR-PH commercial plant is defined as the first process heat plant(s) contracted with guarantees, warranties and performance penalties included in the commercial terms and conditions. Definition of the commercial plant assumes that an industry is in place to furnish plants with a minimum financial involvement required by the government. It is also assumed that the first commercial plant will be preceded by one or more demonstration plants that may encompass replicable components of a commercial plant, including development of technologies necessary for the heat source and components.

The cognizant design agents have the responsibility to design and develop quality power plant systems, components and structures consistent with the overall objective of safe, dependable and economic power generation.

2.0 BACKGROUND/SCOPE

Gas-Cooled Reactor Associates (GCRA) represents the utility/user interest in this Nation's HTGR Program. A key part of GCRA's role is to guide the design and development activities in order to assure their relevance to utility/user interest. Accordingly, GCRA has prepared this specification to define the major plant functional requirements of the HTGR-PH. As the Program proceeds, this specification will be upgraded with quantitative criteria when applicable and additional technical criteria are developed. This specification is intended to be the first embodiment of a plant specification which will ensure the uniform application of the stated criteria to all design agents so that the plant characteristics will conform to the functional requirements of the utility industry, while complying fully with applicable regulatory requirements.

These plant level criteria will form the basis for all inter-system and system level criteria which will be developed and used by the design agents. These lower level criteria will be presented in design criteria documents for specific technical areas (e.g., piping, safety, seismic, electrical, etc.) and in system descriptions, which will extend the definition of requirements and objectives to the extent required to ensure consistent application of the plant level criteria to all systems, components and structures. GCRA will identify those documents which will require their concurrence.

The NHS design agent shall take a leading technical position in recommending the optimum nuclear heat source and primary/secondary helium system conditions, configuration, and performance characteristics to meet the requirements or objectives specified herein. The BOP design agent shall be responsible for integrating NHS, BOP and site interface requirements prescribed by any design agency. Depending upon the specific process heat application, a process design agent may also be involved and be responsible for defining the systems requirements of the process and the energy delivery systems. All technical information developed under DOE funds and in accordance with DOE requirements and certain design agent proprietary data necessary for the design and licensing of this plant shall be made available to GCRA and the NRC respectively during the design and development phases of the plant.

3.0 PLANT REQUIREMENTS/OBJECTIVES

3.1 GENERAL

3.1.1 Standardization

All design and development activity shall be aimed at producing a commercial plant design which will accommodate the requirements of the utility/user industries and which will be pre-reviewed under the NRC standardization program for subsequent use by any utility/user on a specific project.

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The commercial plant design shall include a station plot plan for the following major structures which comprise the power generation block:

- Reactor Containment Building
- Reactor Service Building
- Reactor Control Building
- Fuel Storage Building
- Turbine Building
- Access Control Building
- Engineered Safeguards Structures (Ultimate Heat Sinks, Diesel Generator Cooling/Fuel Storage, etc.)
- Process/Chemical Building

The plot plan shall also include a typical arrangement for the following site specific structures:

- Switchyard Enclosure
- Cooling Towers
- Service and Administration Building
- Helium Storage Area
- Fuel Oil Storage Area
- Fire Protection Pumping and Storage Area
- Training Facilities
- Service and Circulating Water Pumphouse
- Warehouse/Storage Areas
- Security Facilities
- Technical Support Center

The commercial plant design shall also include an arrangement of major plant equipment and piping within the power generation block. This requirement should not limit the choice of equipment suppliers during the initial phases of the design effort. The selection of major equipment configurations that affect plant layout and arrangement shall be evaluated to all appropriate requirements in this specification.

A uniform approach to criteria, descriptions, and specifications (including installation and construction) for systems, components and structures shall be employed throughout the plant design by and among the design agents and their contractors.

The plant design shall be based on concepts, configurations and arrangements of structures, systems and components which have been tested, demonstrated and/or proven reliable in previous or current power programs when at all feasible.

Equipment and material criteria specified throughout the design shall be standardized and to the maximum extent practicable, equipment and materials meeting these criteria shall be commercially available in the United States. This does not, however, preclude the use of equipment or materials made by foreign manufacturers, provided the vendors have the capability of installation, startup, operation and maintenance services and have been evaluated by GCRA.

3.1.2 Design Margins

Design margins shall be applied to all systems and component sizing and performance calculations and safety analyses. Margins shall allow for uncertainties of design analyses, probability of achieving design rating, and applicable experience. The assignment of realistic design margins shall be based on actual experience and performance data collected from other thermal gas reactors to the maximum practicable extent. The design agents shall identify major design margins affecting plant performance, safety and/or availability. These margins will be subject to concurrence by GCRA.

3.1.3 Codes and Standards

All equipment, apparatus, structures, design analysis methods and design requirements shall, in general, comply with all appropriate Codes of Federal Regulation, Nuclear Regulatory Commission Regulatory Guides, and industry codes and standards. State and local

government regulations, codes and standards shall be considered when such requirements have a fundamental effect on the design. At the appropriate time during the design process, applicable codes and standards will be invoked.

3.2 PLANT PERFORMANCE

3.2.1 Capability

Plant design shall be based on generating approximately 1200 MW thermal to the primary heat exchangers. It is an objective to deliver maximum usable process heat to the user within the limitation that electric power will not be imported. The final design net electrical and process heat outputs will depend on the configuration, the application, and the performance ratings of major NHS and BOP components recommended by the design agents. For the selected plant concept, systems shall be designed to generate electricity and process heat at maximum availability and efficiency consistent with the economic objectives in Sect. 7.0. BOP systems shall be sized to suit the maximum capacity of the NHS.

3.2.2 Availability Factor

Availability is defined as the percentage of time, over a one-year period, that the plant is in, or ready for, service at any level of output.

The annual availability factor for the process heat plant must be at a high level in order to serve effectively the users for which the process heat plant is being designed to serve. The availability factor is chosen to provide an achievable, industry-accepted value. Where a specific application of process heat requires a higher availability than achievable by a single plant, it will be provided for by the use of multiple plants.

Sustained plant operation with an annual availability factor of 90 percent (7889 hours per year) shall be a plant design objective. Total plant downtime for all planned maintenance, in-service

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inspection, and refueling shall be no greater than 20 days per year with no greater than TBD days per year allocated for refueling. The sum of allocations for unplanned maintenance shall be no greater than 16.5 days per year.

To achieve the 90% plant availability objective, particular attention shall be given to the following:

- An integrated engineering reliability and maintainability program shall be implemented by the agencies responsible for the design.
- Component availability between overhauls shall be consistent with the plant availability factor objective. When this cannot be done, sufficient redundancy shall be provided to preclude limiting plant availability.
- Minimizing the potential for water and oil leakage into the PCRV shall be a major design objective. Methods shall be provided for determining the location of an oil, steam or water leak in PCRV components such that rapid leak isolation and repair is provided. Methods shall also be provided for easily removing either large quantities of water or small amounts of moisture from the PCRV, should it enter.

3.2.3 Capacity Factor

Plant operation with an annual capacity factor of 80 percent shall be a plant design objective. Major BOP equipment shall be sized to achieve plant operation at near full unit capacity of the plant with a component out of service. Specific reliability criteria and analysis shall be developed during the detailed design stage to insure that the 80% capacity factor can be achieved. In general, an installed spare shall be provided for all continuously operating rotating equipment (excluding the turbine-generator) whose failure would lead to significant reduction in power level or unit outage.

The plant shall be capable of meeting process heat design conditions while the electrical generation equipment is out of service. For non-rotating equipment, operational redundancy requirements shall be established based upon expected component failure probability, duration of repair evolutions and impact on plant power production capability.

3.2.4 Service Life

The plant design shall be based on a service life of 40 years. Material and component selection shall consider service life and periodic maintenance requirements as part of the overall reliability and availability assessment to meet the 40 year plant design life. The design service life of all NHS components unique to the HTGR shall be specified by the NHS design agent. For all plant components with a service life less than 40 years, the design agents shall provide a life cycle component replacement plan and/or maintenance plan that will ensure systems will perform their intended function at the end of their 40 year life.

3.2.5 Operating Characteristics

3.2.5.1 Normal Operation

The plant shall be designed to be capable of continuous operation under fully automatic control at any one sustained power level between minimum self-sustaining load and 100% design power. Manually initiated shim type adjustments of reactor orifice valves and control rods are exempted from this requirement.

3.2.5.2 Abnormal Operation

The ability of the plant to recover or safely shutdown from plant transients associated with sudden shutdown or failure of major NHS or BOP components shall be provided.

The plant design shall be capable of sustaining safe controlled operation for the conditions stated in the following paragraphs.

The plant design shall be capable of rejecting up to full load from the electric distribution network and remain in operation supporting its own auxiliary loads. Steam release to atmosphere is acceptable only for the duration of the transient.

The reactor shall be designed to be capable of continued operation at reduced thermal power following a turbine trip from any load level. The steam system shall be designed to bypass the turbine during this mode of operation.

The plant design shall be capable of startup and continued operation at reduced thermal power output with one loop out of service.

The plant design shall be capable of remaining operational at appropriate reduced load where possible, with other major equipment out of service, e.g., feedwater pump, circulating water pump, condensate pump, etc.

3.2.5.3 Startup and Shutdown

The plant design will have the ability to perform a normal shutdown and return to power at the rate of TBD% per minute at the beginning of core life.

Limitations on startup due to transient xenon buildup shall be minimized; the NHS design agent shall recommend the degree of xenon override capability which is considered necessary and economical to accomplish this requirement.

3.2.6 Reactor Power Level

The reactor core shall be designed for a nominal reactor power level of 1170 MW(t). This is the thermal power level commonly used to define plant size and for which the reactor will be licensed.

3.2.7 Steam Conditions

The high pressure turbine generator will be designed for one of the following steam conditions at the turbine stop valves depending on the application specified:

Main Steam Temperature (°F)/Pressure (psia) - 1050/2400
or
1000/1800

3.3 CONFIGURATION

3.3.1 Overall Plant

The reference plant design shall be based on a single unit configuration and shall include considerations such as security, constructibility, operation and maintenance, access, etc., in determining the most effective configuration. Extension to multiple unit configurations at any site shall be based on a slide along concept. The plant shall consist of one high temperature gas-cooled reactor/heat source, the power conversion systems and balance of plant systems, buildings and facilities as necessary to make a complete power generating station. The process heat portion of the reference plant shall consist of all piping and equipment within the exclusion area boundary fence required to deliver process heat or steam to the user.

3.3.2 Nuclear Heat Source (NHS)

The NHS shall consist of a high temperature gas (helium) cooled reactor having four (4) main coolant loops. Each coolant loop shall contain the primary heat exchanger and one electric motor driven main coolant circulator with its auxiliary service system.

A prestressed concrete reactor vessel will provide the primary pressure containment of the high temperature reactor coolant, and will contain the reactor core, primary heat exchangers, core auxiliary heat exchangers, primary and auxiliary helium circulators, portions of the helium purification equipment to the maximum practicable extent, and control rod drives.

3.3.3 Site Layout

The designated site boundaries, i.e., restricted area boundary (RAB) for normal operation and exclusion area boundary (EAB) for postulated accidents, shall be at least 425 meters from all radioactive release points. An appropriate secondary containment, in addition to the prestressed concrete reactor vessel, shall be provided.

The turbine generators shall be located relative to the containment building in such a way to ensure protection from postulated turbine missiles. For multiple units, the layout shall ensure that turbine missiles from one unit cannot penetrate the containment building on the second unit or vice versa.

Access to the site shall be through a single point; buildings which have normally high personnel traffic, e.g., administration building, visitor's center, etc., shall be located outside the primary security perimeter (protected area boundary). Within the primary security perimeter, personnel access and health physics control shall be integrated to optimize the monitoring of personnel traffic within the power generation block.

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The plant's storage capacity for spent fuel shall be based on 1.3 cores of fuel capacity. The station layout shall provide additional space for spent fuel storage to accommodate all fuel used during the 40 year plant life. Building relationships in the nuclear island shall be arranged such that expansion of the spent fuel storage facility can be readily accomplished even after the plant has become operational.

Separation between engineered-safety features facilities, such as the ultimate heat sink, etc., shall primarily be by distance; if this is not practical, structural barriers (existing structures) shall be interposed between any two safety trains, common to such facilities, to avoid common-mode failure from natural or nonnatural design basis events.

Rail and truck access within the site shall be provided for transportation of equipment, new and spent fuel, radioactive waste, supplies, etc. It shall be assumed that rail transportation is available for the reference site.

Buildings shall be so arranged as to avoid the possibility of confined deflagration; i.e., use of confined spaces where flammable or explosive materials might be handled or transferred should be avoided.

3.3.4 Building Arrangements

The plant layout and equipment/piping arrangement shall provide access for orderly construction, maintenance, and inspection in addition to the optimum layout for functional equipment grouping, operator convenience, personnel protection from radiation exposure and required separation between redundant safety equipment and systems.

An effort shall be made to achieve the highest degree of constructibility possible by special cost-effective design considerations

such as modularization, functional equipment grouping, prefabricated equipment assemblies and automatic fabrication processes. Modularized and prefabricated assemblies, when used, should carefully consider maintenance access requirements and requirements for shop assembly by craft unions to avoid disassembly/reassembly problems on-site.

Provisions for decommissioning and ultimate disposal of radioactive portions of the plant shall be considered in the design, including ease of disassembly, decontamination, radiation exposure and burial.

The design agents should consider the use of models during the design process to verify arrangement requirements such as those stated herein. Scale models may be used for overall plant or building arrangements; however, full scale models should be considered for specific areas where arrangement space is limited or unusual conditions exist (e.g., control room layout, reactor top head layout). An overall plant model shall be constructed by the architect/engineer, if required.

3.3.4.1 General Arrangement Considerations

Each building shall be arranged to achieve proper balance between systems performance, operability, maintainability, constructibility and initial investment cost.

The turbine plant shall be an indoor type system, requiring a fully-enclosed turbine building, including the turbine building crane(s).

Each building shall be compartmented into areas according to the potential for radioactive release, pipe breaks in fluid systems, fire potential, and equipment separation requirements. Compartment pressure for potentially radioactive areas should also be considered to limit outward

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leakage. Each safety train and associated equipment in various compartments shall be served by a unique HVAC system to ensure protection against environmentally-induced common-mode failures. The HVAC design shall be such that the flow of air is always from nonradioactive to potentially radioactive areas.

A 200-foot separation shall be maintained between buildings, components, and piping containing process gases and any safety-related plant structure or components. In lieu of separation, the appropriate physical barriers or systems design shall be incorporated to preclude damage to safety-related plant structures and components as a result of postulated process gas explosions.

Separation between various engineered-safety features systems and components shall be by distance or by structural barriers. In general, distance is preferable if it can be achieved without cost penalty.

Electrical and I&C components associated with different safety divisions shall be located in different noncommunicating rooms/compartments/tunnels.

Where possible, components handling or processing radioactive or potentially radioactive material shall be arranged in contiguous areas separate from nonradioactive areas to optimize access control and control the spread of radioactive contamination.

3.3.4.2 Access

Normal access to the plant shall be through only one access control facility.

Normal access to the power generation block, except for the turbine building, shall be through only one point from which

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personnel can proceed to uncontrolled areas or to the access control point for the controlled areas.

Normal access to controlled areas shall be only through the change rooms in the health physics areas.

Access to these areas for unusual or emergency situations shall also be provided as necessary.

Accessibility criteria for each radioactive component shall be developed on the basis of:

1. Intrinsic radiation level in the area where the component is located.
2. Radiation level of the component.
3. Frequency and average duration of the operational activities required.
4. Frequency and average duration of the maintenance activities.
5. Frequency and average duration of inspections and tests.
6. Security classification.

The values of the cumulative doses to personnel from these criteria shall form the basis for configuration, shielding and access designation, with the underlying purpose of ensuring personnel exposure as low as reasonably achievable.

Instrumentation required for continuity of plant operation shall not be located in areas where access would require a plant shutdown. Access routes to instruments requiring routine accessibility shall be located in low radiation zones. Otherwise, access route zoning shall be consistent with the inspection frequency and duration, and the radiation environment associated with the area in which the instruments are located.

Instrument and electrical cabinets and local panels associated with systems throughout the plant shall in general be located in low radiation zones.

3.3.4.3 Maintainability

A plan shall be prepared for all plant equipment which addresses the requirements for inspection, maintenance, repair and removal or replacement. This plan shall address the economic considerations of working on the equipment in place versus making provision for removal and remote repair. Working on equipment in place will require provision for handling equipment, pull space, laydown space and possibly on-the-spot decontamination. Remote repair or replacement will require provision for handling equipment, access through the plant to the equipment.

The PCRVR shall provide a means for removal of all components contained within the PCRVR cavities including core components, primary heat exchangers, helium circulators, auxiliary core cooling heat exchangers and helium purification system components. The capability to isolate these cavities for component removal shall also be provided. Permanently installed reactor internals such as the PCRVR liner, thermal barrier, hot gas ducts, spring packs, and side reflectors are excepted from these requirements.

Space and structural capacity shall be provided in the reactor containment building and the selected contiguous building(s) for temporary handling equipment to remove, decontaminate, and ship a primary heat exchanger, as well as other such major components in or around the PCRVR.

Pull space shall be provided for all shell and tube heat exchangers, pumps, motors, valves, etc.

High maintenance components, e.g., valves and pumps, associated with systems processing radioactive materials shall be arranged in shielding configurations such that the required maintenance access to them can be achieved in compliance with the As-Low-As-Reasonably-Achievable (ALARA) criteria. Limiting the number of such components to a minimum will be a major design objective.

A central decontamination facility and a small hot machine shop shall be provided. Local decontamination facilities (portable or temporary in-situ setup) for components which are maintained in-place shall be provided for in the design.

3.3.4.4 Inspection and Testing

NHS and BOP equipment and systems shall be designed for inspection and testing where such an inspection and/or test program will improve plant availability, verify the readiness of safety related functions, or where it is required by applicable codes, standards, and licensing requirements. The need for and capability of achieving in-service inspection of the PCRV liner, primary heat exchangers, and other components located inside the PCRV shall be evaluated by the NHS design agent. In-service inspection requirements of all other NHS components will also be evaluated by the NHS design agent. The necessary accessibility requirements, preferred component configuration and examination methods shall be factored into the design.

3.4 FUEL AND FUEL CYCLE

The fuel design must be licensable and available to meet the commercialization program schedule. The fuel shall be designed to achieve full exposure through a core residence time of four years or more with annual reloading without requiring a reduction in power. For 950°C core outlet temperature plant designs, the fuel will be designed for a core residence time of three years or more. The

fuel element design shall allow HEU or LEU fuel cycles, with or without fuel recycle, to be employed without modification of plant components or facilities.

The fuel cycle chosen must consider the conservation of uranium resources and should be consistent with the economic objectives of Section 7.0.

Spent fuel shall be stored in a fuel storage facility. Consideration will be given to eventual recycle and ultimate disposal as required for assessment of environmental impact and licensing, as well as to ensure proper interface with design requirements for ancillary facilities.

The design level of circulating and plated-out activity in the primary coolant helium circuit shall meet ALARA criteria to minimize personnel exposure during maintenance operations, but in no case should these levels cause the total allowed exposure for the station crew to be exceeded during expected maintenance operations; i.e., there should not be a need to provide additional personnel for such maintenance because of exposure limits.

3.5 OPERATING ENVIRONMENT

The plant shall be designed to ensure that appropriate environments during normal operation for personnel and equipment are established and maintained. As a corollary, equipment shall be designed to withstand the environment it will be located in without operational degradation.

3.5.1 Area Ambient Conditions

Ambient conditions for temperature and humidity during normal operation in various areas and compartments shall be established based upon the type of equipment located and the operational activities which will be conducted therein.

3.5.2 Radiation Protection

The radiation protection philosophy that shall govern the plant design is to control radiation exposure to plant personnel and the general public within the applicable prescribed limits under all anticipated normal and abnormal plant operating or accident conditions. The ALARA criteria shall be applied in the design, which shall encompass all operational phases such as routine inspections, maintenance operations, refueling operations, in-service inspections, periodic tests, etc. Component arrangement, radiation shielding design, HVAC design and procedures for personnel access management and control shall be systematically reviewed to ensure compliance with ALARA. Personnel exposure to radiation shall be determined from the cumulative effects of fixed and airborne radiation sources wherever practicable. Consideration shall be given to the additional neutron shielding requirements imposed by the use of low enriched uranium (LEU) fuel for the reference design.

The plant shall be divided into various radiation zones for access control, in compliance with Regulatory Guides 8.8 and 8.10 and 10 CFR 20.

3.6 OPERATIONAL CONTROL

The plant shall be operated from a central control room which will contain instrumentation and control equipment required to startup, operate, and shutdown the plant for normal conditions and to shutdown the plant under accident conditions. The reactor control system shall also be designed to permit a safe and orderly shutdown to cold plant conditions from outside the main control room.

System and control simplicity and ease of plant operation shall be high priority design objectives. Special attention shall be given to prolonging the time available for restoring reactor cooling after complete loss of forced circulation and to simplicity in the required operator actions.

The plant instrumentation and control system design shall monitor and annunciate, when necessary, all signals required to determine the status and performance of major plant functions and protective systems. A plant computer(s) shall be provided to collect and compute this information; however, it will not be required to perform any safety related functions.

The reactor control system, in conjunction with reactor protective systems, shall be such that no single operator error or equipment malfunction shall cause fuel damage or create a continued unsafe plant condition. Safety grade control systems will have on-line testing capabilities in accordance with applicable codes and standards. All other control systems will have provisions in the design for periodic testing, inspection, or surveillance.

4.0 SITE REQUIREMENTS

The reference plant design shall be based on a reference or hypothetical site having the parameters shown in Table I. For seismic design purposes, two (2) combinations of ground acceleration and soil characteristics are defined, both of which must be satisfied.

5.0 SAFETY AND ENVIRONMENTAL IMPACT

The plant shall be designed to protect the health and safety of the public through all phases of normal and abnormal (including accident) plant conditions, in compliance with all relevant regulatory requirements, codes and standards. Appropriate referencing to Federal Regulations, Industry Standards, NRC Regulatory Guides and Standard Review Plans, etc., shall be made for each criteria category.

6.0 QUALITY ASSURANCE

The effort of all organizations and individuals involved in the development of the HTGR-PH power plant from conceptual through detailed design, procurement, fabrication, construction, testing, startup, and operating shall be characterized by the commitment to high quality.

PROJECT TECHNICAL REQUIREMENTS

GAS-COOLED REACTOR ASSOCIATES

TABLE I
SITE PARAMETERS

A. Site Conditions

1. Soil Characteristics	Firm Soil	Firm Soil - Hard Rock
Shear Wave Velocity (fps)	1000-1200	1200-8000
Soil Shear Modulus (psi)	1.7×10^4 - 2.5×10^4	2.5×10^4 - 2.5×10^6
Allowable Static Bearing Capacity (KSF)	10	10
2. Foundation	No special compensating foundation required. Assume shallow embedment of reactor building.	
3. Water Table	Normal groundwater elevation is approximately eight (8') feet below grade	
4. Precipitation (Snow)	Snow load: 20 psf	
5. Wind Velocity	100 mph at a height of 30 ft. above grade per ANSI A58.1.	
6. Air Temperature	Dry Bulb	Wet Bulb
Hottest Day of Record	110°F	79°F
Coldest Day of Record	-20°F	N/A
7. Meteorological		
Exclusion Area Boundary (EAB)	425 meters, minimum, from reactor release point	
Restricted Area Boundary (RAB)	Same as EAB	
Low Population Zone (LPZ)	1600 meters	
Atmospheric Dispersion X/Q Values	Annual average; equivalent ground level release - 2×10^{-5} sec/m ³	
8. Water Source	Nonbrackish river water (<500 ppm TDS)	

PROJECT TECHNICAL REQUIREMENTS

GAS-COOLED REACTOR ASSOCIATES

TABLE I (Continued)

SITE PARAMETERS

B. Site Events

1. Seismic

Maximum Horizontal Ground

Acceleration:

Safe Shutdown Earthquake

Operating Basis Earthquake

Firm Soil

0.3g

0.15g

Firm Soil - Hard Rock

0.3g

0.15g

2. Tornado

Designation (RG 1.76)

Tangential Velocity

Translational Velocity

External Pressure Drop

Zone I

290 MPH

70 MPH

3.0 psi @ 2 psi/sec.

3. Flooding

No special provisions required. Maximum probable flood level below plant grade.

4. Aircraft Hardening,
Industrial/Transportation
Accidents

No special provisions required.

Documentation (e.g., bases, description, interface data, etc.) for engineering and design concept choices shall be properly reviewed, reported and permanently stored.

The quality assurance program applied to nuclear safety-related structures, systems and components shall be in strict compliance with applicable codes, standards and federal regulations. The quality assurance program of design agents, equipment manufacturers and engineering service organizations working on the HTGR-PH reference plant design will be subject to GCRA review. During the course of the work, GCRA will audit the activities of these participating organizations to assure that they are implementing their approved quality assurance programs.

The quality assurance program implemented for non-nuclear safety-related structures, systems and components shall be sufficient to ensure that the intended design functions are achieved and the reliability performance is acceptable.

The details for the above programs shall be presented in quality assurance manuals by the participating organizations.

7.0 ECONOMICS

7.1 ENERGY GENERATION COST

The cost of generated energy, considering capital cost, fuel cost, operation and maintenance cost, capacity factor and other evaluated costs must not exceed that for competing systems in the year of perceived commercial deployment. Evaluated costs include equivalent cost for other factors such as safety features, water utilization, radiation considerations, cost uncertainties, etc.

7.2 CAPITAL COST

A concerted effort shall be made during the entire design process to minimize plant capital cost. However, design and component selection activities shall not compromise or degrade plant reliability, availa-

bility, maintainability, or capacity factor to reduce capital cost unless it can be shown that the net economic performance is improved.

7.3 PLANT OPERATING AND MAINTENANCE COST

A concerted effort shall be made during the design process to minimize plant manpower requirements and plant consummables. System design and equipment selection shall consider labor cost requirements for both operation and maintenance. Particular attention shall be paid to providing the necessary accessibility to plant equipment so that maintenance, repair or replacement can be made in reasonable downtime, thereby minimizing the impact on the plant availability factor.

Minimizing helium leakage shall be a high priority system design objective. Particular attention shall be paid to this factor in the selection of valves, fittings and components.

7.4 ECONOMIC PARAMETERS

In preparing the cost estimates and in evaluating design trade-offs and determining the cost-effectiveness of certain design decisions, the following cost parameters shall be used:

Region: Northeast Region near Wilmington, DE
Commercial Plant Basis

Capacity Factor

Base Date for all Costs

Date of Operation for all Plants

Investment Life for all Plants

Electricity Replacement Power Costs

1995 Fuel Cost Projections (Jan. 1980 \$)

Coal

Oil

Natural Gas

Uranium

Conversion

Separative Work (.2% tails)

Nuclear Fuel Cycle Costs:

Nth Plant

70%

January 1980

January 1995

30 Years

40 mills/KW-hr

2.25 \$/MBtu

9.25 \$/MBtu

8.25 \$/MBtu

40 \$/lb U₃O₈

6 \$/kg UF₆

120 \$/SWU

Based on detailed analysis at
General Atomic

Operation and Maintenance Costs (Jan. 1980 \$)

HTGR-SC, SC/C

HTGR-SETS, R

LWR

Coal

Fixed
[\$/KW(t)-yr)]

TBD

TBD

TBD

TBD

Variable
[\$/KW(t)-h]

TBD

TBD

TBD

TBD

Common Cost Factors - Utility-Owned Facility

Weighted Cost of Capital

Levelized Fixed Charge Rate

Allowance for Funds During Construction

Constant
Dollars

4.3%

8.5%

3.5%

Inflated
Dollars

10.5%

TBD

TBD

Common Cost Factors - Private-Industry-Owned Facility

Weighted Cost of Capital

Levelized Fixed Charge Rate

Allowance for Funds During Construction

7.4%

13.2%

6.9%

13.8%

TBD

TBD

Real Escalation Rates -

Base Inflation

Construction

O&M

Electric Power

Fuel (All)

6%

6%

6%

6%

1.00%

1.00%

2.00%

3.00%

7.06%

7.06%

8.12%

9.18%

Levelizing Factors (30-Year Levelized)

O&M

Electric Power

Fuel (All)

1.136

1.297

1.490

2.108

2.408

2.767

APPENDIX N

FILE: PRELIMINARY PROBABILISTIC RISK
ASSESSMENT FOR PROCESS SIDE OF HTGR-PH

APPROVAL LEVEL 2

PAGE 1 OF 49

ABSTRACT

This study is a preliminary probabilistic risk assessment of the 1170 MW(t) HTGR-PH (reformer) plant. The primary interest of this study was to determine the hazard posed to the nuclear plant by the reformer and its associated equipment. The major hazard to the nuclear plant is posed by vapor cloud explosions (VCE's), in particular vapor clouds which explode as they drift toward the nuclear heat source. This study looks at vapor release scenarios initiated by a compressor failure in the reformer train. This failure leads to the release of synthesis gas (primarily hydrogen and carbon monoxide) to the atmosphere. The release is modeled as a puff release of gas, using Gaussian dispersion characteristics to describe the vapor cloud dispersion. Ignition and detonation of the cloud leads to blast overpressures in the nuclear plant area, possibly causing damage to the containment building, the ultimate heat sink structure, or the diesel cooling and fuel oil storage building leading to core heatup and eventual fission product release. Consequences to the public were determined by scaling known results obtained from similar core heatup sequences for the HTGR-SC (steam cycle). From that scaling, the highest risk scenario was that in which VCE damage causes loss of containment integrity and core heatup.

The overall result of this preliminary study is that vapor cloud explosions initiated by compressor failure in the reformer train pose an additional risk to the public that is similar in size to the risk associated with a normal HTGR-SC plant and is therefore small. The uncertainties on this result are large and a detailed uncertainty analysis is needed in order to bound the range of predicted values. This study, however, only looked at the incremental risk due to a single initiating event and further PRA work must be done to confirm these results and investigate more fully this complex problem of damage to the nuclear plant due to potentially explosive vapor clouds and the risks of additional initiating events and accident sequences.

This report satisfies milestone A1 of task number 7213070001, serving as an update of previous work performed during FY-80.

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1.0 INTRODUCTION

The purpose of this study was to perform a probabilistic risk assessment of the indirect cycle HTGR-PH (reformer) plant. A first assumption was made that the only risks to the public that were significantly different than those from a steam cycle plant were those risks associated with the process plant. For this reason, this study looks only at process plant hazards and their associated risk to the public.

1.1 BACKGROUND

In studying the risk to the public we are primarily interested in event sequences which lead to release of radioactivity to the atmosphere. Since core heatup threatens release of fuel body inventory and is the dominant risk contributor, only event sequences leading to core heatup were investigated. Event sequences leading to this undesired end result can be initiated by process plant hazards which include: vapor cloud explosions (VCE's), vapor cloud fires, and other fires associates with the handling of combustible materials. These hazards can lead to, basically, one of five threats to the nuclear plant which could cause core heatup. These threats include AC power loss, total or partial containment collapse, main loop and CACS loop loss, air blast heat exchanger loss (diesel or CACWS), control room and RSB loss.

2.0 METHODOLOGY

In order to systematically proceed through this risk assessment it was necessary to develop a methodology for study. Figure 2-1 shows a diagrammatic representation of the methodology used in this study.

It was first necessary to understand the plant as it is currently designed. This meant knowing where the various buildings (containment, reformer train, ultimate heat sink, etc.) are in relation to each other, understanding the design and materials of construction of these buildings, and understanding the location and relation of key safety and core cooling systems. It also included understanding the reforming process, the reformer train components, and the process side layout. Since the design of the process plant is still only at the conceptual level, many assumptions had to be made about the layout and design, these assumptions and other details of the process plant are given in Appendix A.

Once the plant design was understood, initiating events could be found. Initiating events are component failures which lead to a combustible gas release. These include pipe rupture, pressure vessel rupture, and others. Process plant scenarios were then developed in order to better understand what could happen to the combustible gas in the process plant once it was released from one of the components. These scenarios assisted in generating event trees, beginning with a specific initiating event and ending in core heatup and fission product release. Vapor release descriptions were developed to characterize the manner in which the combustible gas escaped from the reformer train buildings to the atmosphere.

From these descriptions and knowledge of the size and composition of the release, models for the behavior of the combustible cloud were developed. These models described the displacement of the cloud through the atmosphere, its potential burning and sometimes the blast produced by

FIGURE 2-1
METHODOLOGY DIAGRAM

the explosive cloud. With knowledge of cloud blast characteristics and plant building design it was possible to calculate characteristic NHS damage for a given cloud.

Based on the obtained results, it was then possible to find the dominant considerations for the safety risk, which leads to suggestions for future PRA work, design modifications, and possible safety research areas.

3.0 PLANT CONCEPT

The basic plant design used in this study is in accordance with the plant drawings by United Engineers and Constructors (Ref. 1). Information on the methanation train flows and heat balance are from data supplied by General Electric (Ref. 2). The plot plan for the plant is shown in Figure 3-1 (Ref. 3), labeled are the containment building, the ultimate heat sink structures, and the diesel cooling and fuel oil storage building. These buildings are of primary interest in this study, as they contain many of the core cooling related components and systems which are susceptible to damage by VCE's. Also labeled are the reformer train buildings, which contain the reformers, reformer train, and associated equipment. Figure 3-2 (Ref. 4) shows the general arrangement of one of the reformer train buildings, giving the relative position of the reformer and prestressed concrete pressure vessel (PCPV), heat exchangers, and compressors. Very little piping is shown on this diagram, however, in reality this building will be crowded with piping. The layout lends itself to a very complex system of piping due to the separation of compressors and coolers and the confinement which the building surrounding the components imposes (Ref. 5). Design assumptions made are presented in Appendix A.

Figure 3-1

Figure 3-2
General Arrangement of
Reformer Train

ELEVATION A-A

4.0 INITIATING EVENTS

Some component failure leading to a release of inventory from the system must occur in order to release combustible gas to the environment. Table 4-1 lists the five most important (and frequent) failure modes for the process plant, their component failure rates, the quantity of the specific component in the plant, and a plant failure rate. Of these five, valve stem leak has, by far, the highest plant failure rate. Because of this fact, valve stem leaks were investigated as a possible initiating event for combustible vapor release. For a typical valve stem leak, the leak rate is on the order of five to six gallons per day. It was found that, for that size leak rates, combustible gas could never accumulate to a point where ignition could lead to events which could damage the nuclear plant (Ref. 6). The other four failure modes all lead to relatively large releases (and release rates), and among them compressor failure has the highest plant failure rate. For this reason, and the fact that no reason was known to believe that any of the other initiating events would lead to higher risk, compressor failure was chosen as a representative initiating event to be studied in depth. By compressor failure we are referring to a rupture of the casing due to the throwing of blades. The possibility of blades as projectiles was considered, but was found to be of little significance in the overall evaluation. It must be pointed out that, although event trees for the other initiating events are likely to be similar, the frequencies and consequences included in those trees may be different.

TABLE 4-1

PROCESS SIDE COMPONENTS AND FAILURE RATES

<u>Component</u>	<u>Failure Rate</u>	<u>Quantity</u>	<u>Failure Rate/Plant-Yr</u>
Valves	8×10^{-2} /valve-yr* (Steam Leak)	~50	4.0/plant-yr
Compressors	5×10^{-4} /comp-yr**	16	8×10^{-3} /plant-yr
Valves	8×10^{-5} /valve-yr* (Valve Rupture)	~50	4×10^{-3} /plant-yr
Pressure Vessels (Heat Exchangers, Dryers, etc.)	5×10^{-5} /vessel-yr**	36	1.8×10^{-3} /plant-yr
Piping	3×10^{-7} /meter-yr**	~1500 meters	4.5×10^{-4} /plant-yr

* - GCR Databank (Ref. 8)

** - Canvey Island (Ref. 7)

5.0 EVENT TREE LOGIC

From the compressor failure initiating event an event tree was developed to help first organize and later quantify the problem. This tree is shown in Figure 5-1. The event tree begins with a compressor failure and subsequent release of gas into the reformer train building. Once this gas is released many things can occur including first, the gas could ignite and explode and the initial release could continue to be expelled, unburned (much like a blast extinguishing an oil well fire); second, the gas could ignite and cause a blast, followed by burning of the initial release as a torch at the point of release; third, the gas could ignite and burn as a torch, without a blast; and fourth the gas could fail to ignite and escape out of the building, unburned. If there had been a blast or if unburned gas escaped from the reformer train building and then ignited, causing an explosion, then the adjacent reformer train buildings could be damaged such that they become a source for new, unburned gas. The adjacent reformer buildings can be damaged in one of two ways: by the initial blast from the compressor failure release (first release) or by an explosion from gas being expelled from the train building, either before or after the initial blast occurs (new release).

The unburned gas from the reformer train buildings may pose a hazard to the nuclear plant, if the wind blows the release toward the nuclear plant buildings. Given the gas is over the nuclear plant, there is some probability that it will ignite and some probability that given ignition it will detonate producing a detonation wave followed by a shock wave (i.e. a blast).

As a consequence of a detonation over the nuclear plant and with the knowledge that, because of damage in the process plant, main loop cooling has been lost, leaving the plant totally dependent upon the core auxiliary cooling system (CACS), the damage to the plant can be categorized in four important ways: loss of three CACS loops; loss of two CACS loops and

failure of the third independently; containment building damage and resulting loss of three CACS loops; and loss of no, 1 or 2 CACS loop(s). For a given damage there is, then, some probability that the damage could be repaired before the maximum time to restore cooling (MTRC) is passed, otherwise a core heatup occurs and fission products are eventually released to the atmosphere.

compressor failure	mode of release	no damage to adj. bldg.	moves toward plant bldg	detonation	Damage plant initiates core heatup sequence	Damage not repairable, fission products released
	detonation w/o torch				loss of 3 loops	-----
					loss of 2 loops + failure	-----
					CB damage	-----
					loss of no, 1 or 2 loops	-----
	1 st release				3 loops	-----
					2 loops + failure	-----
					CB	-----
					no, 1 or 2 loops	-----
	new release				3 loops	-----
					2 loops + failure	-----
					CB	-----
					no, 1 or 2 loops	-----
	detonation w/ torch	1 st release			3 loops	-----
					2 loops + failure	-----
					CB	-----
					no, 1 or 2 loops	-----
	no ignition				3 loops	-----
					2 loops + failure	-----
					CB	-----
					no, 1 or 2 loops	-----
	torch	new release			3 loops	-----
					2 loops + failure	-----
					CB	-----
					no, 1 or 2 loops	-----

Figure 5-1

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6.0 VAPOR CLOUD CHARACTERISTICS

The models used for the combustible vapor clouds were compiled by Landoni and are described in Document No. 905311 (Ref. 9). This model is for instantaneous ("puff") releases and can model cloud performance in all six Pasquill stability classes (A through F). Gaussian dispersion characteristics are assumed for the cloud, whose vertical displacement is predicted according to the theory of thermals, and horizontal displacement determined by full entrainment by the wind. The potential explosive behavior is predicted by the point explosion model for unbounded detonable mixtures, taking into account the amount of gas contained in the flammable region of the cloud and the position of the cloud (vertical and horizontal) relative to various buildings in the plant at specific time intervals along the trajectory of the cloud. An example of the overpressure produced by the detonation vs. distance for various size clouds is given in Figure 6-1. This figure gives peak static overpressure (PSO) vs. distance from the center of the cloud for cloud sizes of 100, 3000, and 100,000 lbs. All of these clouds have PSO's of approximately 325 psi inside the burning cloud, but, as can be seen, the "reach" of the explosion is greatly a function of cloud mass. For the 100 lb cloud, for example, the PSO drops to less than one psi within approximately 50 ft, whereas for the 100,000 lb cloud the PSO doesn't drop to one psi until approximately 1000 ft. For the initiating events considered in this study, the clouds of most interest, however, are those in the 100 to 6000 lb range because one isolated train contains about 6000 lbs of gas. Each train has isolation valves on the incoming and outgoing gas lines with multiple sensors to detect large changes in flow, temperature, pressure, etc. which automatically, with a high reliability, isolate the train and thereby limit the amount of gas released. Deflagration explosions were also considered, but, since the clouds considered in this study are buoyant, in terms of plant damage the overpressures produced by deflagrations are insignificant.

Figure 6-1
Peak Static Overpressure
vs.
Distance From Combustible Vapor Cloud

7.0 CHARACTERISTIC NHS DAMAGE

It was initially thought that the area in the plant most vulnerable to damage by VCE's was the containment building. In order to determine the dynamic response of the containment to VCE's, an elaborate computer model was developed by the Structural Dynamics Branch (Ref. 10). This computer code uses a very large finite element model for the containment to determine the building's response to a theoretical point source explosion occurring 200 ft away. Studies were done with overpressures of approximately 2 psi and it was found that there would be no damage to the building at those pressure levels, and that it could withstand overpressures an order of magnitude higher without sustaining any damage. The overpressure needed to blow-in part of the containment, breaking the containment liner, showering in large pieces of concrete onto the top of and down beside the PCRV, it was extrapolated from these results and was found to be approximately 100 psi. Combining these results with the VCE blast overpressure vs. distance plot, it is obvious that the only time the containment is vulnerable to damage is when a VCE occurs within approximately 50 ft of the containment.

Damage to the nuclear plant in other areas was also investigated. Calculations were done by the Structural Dynamics Branch in order to determine the overpressure needed to damage walls of the various buildings containing core cooling systems or components. Buildings evaluated included the ultimate heat sink structure (UHS), the diesel cooling and fuel oil storage building (DCFSB), the containment annulus building, and the control and auxiliary diesel building. The analysis was done by calculating the blast overpressure needed to damage, sufficient to blow in large amounts of concrete, the largest (weakest) wall in each building. This limit was taken because it was felt that elastic deformations of the walls could not cause sufficient damage to the components within the buildings to render them inoperable. The results of these studies are shown in Table 7-1. Full details on this work are given in Ref. 11. When

TABLE 7-1

BLAST OVERPRESSURES NECESSARY FOR BUILDING DAMAGE.

<u>Building</u>	<u>Overpressure</u>
Containment Annulus Building	100 psi
Control and Auxiliary Diesel Building	60 psi
Ultimate Heat Sink Structure	110 psi
Diesel Cooling and Fuel Oil Storage Building	120 psi
Containment Dome	100 psi

these results were combined with the vapor cloud characteristics, it was found that overpressures, sufficient to structurally damage these buildings, did not occur. That is, overpressures of 60-100 psi did not occur at the elevations of these buildings.

Core cooling system components, in particular the air blast heat exchanger fans, were also examined in order to determine their vulnerability to VCE's. Blast wave propagation through the air intake ducts of the UHS were modeled using the WAVENET computer program for the transient response of a one-dimensional duct, of the same proportions as those in the UHS, to a transient acoustic load (blast wave pulse) (Ref. 12). The main result was that the initial overpressure would be reduced by 50% for the duct analyzed. Other calculations showed that an overpressure of only one psi at the fan could bend the blades such that the fan would be inoperable (Ref. 13). By combining these two results it was found that an overpressure of only two psi at the UHS structure was sufficient to render the CACS loop inoperable. Since two of the UHS structures are adjacent to each other, this means that a single, relatively distant cloud can damage two CACS loops.

The DCFSB has a similar ducting system and a similar heat exchanger; thus rather than performing another complete analysis, it was assumed that an overpressure of two psi would also damage a diesel cooling heat exchanger fan and keep the associated diesel from operating. The three DCFSB are all adjacent to each other so, it is possible, by one VCE, to damage all DCFSB heat exchangers, keeping all the diesels from operating. This circumstance only poses a hazard to the nuclear plant if the same cloud that damages the three DCFSB is also able to damage the equipment associated with supplying offsite power to the plant, or if offsite power at that time is not available for some other reason. This type of accident would then initiate a core heatup sequence because the plant would be without AC power.

A summary of these results is shown in Table 7-2.

TABLE 7-2

KEY PLANT COMPONENTS NECESSARY FOR CORE COOLING

Component	Location	Blast Overpressure Necessary to Prevent Operation
Air blast heat exchanger fans for CACWS	Inside ultimate heat sink structures	2 psi
Diesel cooling heat exchanger fans	Inside diesel cooling and fuel oil storage building	2 psi
Diesel generators	Basement of control and aux- iliary diesel building	60 psi
Control room and control wiring	Inside (no external walls) control and aux. diesel building	60 psi
CACWS components and wiring	Inside containment building	100 psi

8.0 COMPLETED EVENT TREE

The event tree for an initiating event of a compressor failure shown in Figure 5-1 is now quantitatively interpreted in Figure 8-1. Probabilities are assigned for each branch and total probabilities per reactor year are indicated for core heatup branches. Complete details on how the probabilities for each branch were estimated are given in Appendix B. The two areas in which the analysis is most sensitive are the frequency of the initiating event (compressor failure) and the calculation of the probability of damage to the plant. The frequency of a compressor failure, as noted before, comes directly from literature on process plant type experience with comparable equipment and can be expected to be relatively accurate. The calculation of the probability of damage to the plant, however, is more involved and requires further elaboration.

8.1 Probability Calculations for Damage to Plant

If the heat sink associated with the main loop has been lost due to damage in the process plant (reformer train) area, the nuclear plant would be totally reliant on the CACS to supply core cooling. The CACS for the 1170 MW(t) HTGR-PH plant consists of three independent loops, each with 100% capacity to cool the core while pressurized, and 50% capacity while depressurized. For the scenarios considered in this study, the primary loop is always pressurized, so the plant requires one CACS loop for core cooling. Consequently, the damage inflicted to the nuclear plant by VCE's can be divided, basically, into four categories: loss of three CACS loops because of the explosion; loss of two CACS loops by the explosion and failure of the third independently; containment damage and resulting loss of three CACS loops; and loss of no, one or two CACS loops. A breakdown of damage in these categories is given in Table 8-1. Loss of three loops includes loss of three UHS heat exchanger fans, or loss of three DCFSB heat exchanger fans and loss of offsite power (LOSP), or loss of control room. Loss of two loops and failure includes loss of two UHS heat exchanger fans and failure of the third loop, or loss of two DCFSB heat exchanger fans and

TABLE 8-1

DAMAGE TO PLANT CATEGORIES

DAMAGE TO PLANT

- o LOSS OF 3 LOOPS
 - o Loss of 3 UHS heat exchanger fans
- or
- o Loss of 3 DCFSB heat exchanger fans + offsite power
- or
- o Loss of control room

- o LOSS OF 2 LOOPS + FAILURE
 - o Loss of 2 UHS heat exchanger fans & failure of remaining loop
- or
- o Loss of 2 DCFSB heat exchanger fans + offsite power & failure of remaining loop

- o CONTAINMENT BUILDING DAMAGE
 - o VCE causing hole in containment
- and
- o Falling concrete damaging core cooling systems

- o LOSS OF NO, 1 OR 2 LOOPS
 - o No core heatup

Figure 8-1

Compressor failure	mode of release	no damage to adj. bldg.	no damage to plant bldgs.	detonation	Dangerous plant initiates core heatup sequence	Dangerous not repairable, fission products are released		
8×10^{-3}	0.15 detonation w/o torch	0.10	0.37	0.50	loss of 3 loops $\sim 4.2 \times 10^{-5}$	0.90	8×10^{-10}	3L
					loss of 2 loops $\sim 4.6 \times 10^{-6}$	0.10		
					+ failure	0.90	9.2×10^{-11}	2L
					CB damage $\sim 5.3 \times 10^{-4}$	0.99	1.2×10^{-8}	CB
					loss of no, 1 or 2 loops ~ 1	0.01		
				0.50				
		0.60 1st release	0.63	0.37	3 loops $\sim 4.2 \times 10^{-5}$	0.90	5.0×10^{-9}	3L
					2 loops $\sim 4.6 \times 10^{-6}$	0.10		
					+ failure	0.90	5.5×10^{-10}	2L
					CB $\sim 5.3 \times 10^{-4}$	0.99	7.0×10^{-8}	CB
					loss of no, 1 or 2 loops ~ 1	0.01		
				0.50				
		0.30 new release	0.63	0.37	3 loops $\sim 4.2 \times 10^{-5}$	0.90	2.5×10^{-9}	3L
					2 loops $\sim 4.6 \times 10^{-6}$	0.10		
					+ failure	0.90	2.8×10^{-10}	2L
					CB $\sim 5.3 \times 10^{-4}$	0.99	3.5×10^{-8}	CB
					loss of no, 1 or 2 loops ~ 1	0.01		
				0.50				
			0.63					
	0.35 detonation w/ torch	0.10	0.37	0.50	3 loops $\sim 4.2 \times 10^{-5}$	0.90	1.8×10^{-8}	3L
		1st release			2 loops $\sim 4.6 \times 10^{-6}$	0.10		
		0.90			+ failure	0.90	1.9×10^{-9}	2L
					CB $\sim 5.3 \times 10^{-4}$	0.99	2.4×10^{-7}	CB
					loss of no, 1 or 2 loops ~ 1	0.01		
				0.50				
			0.63					
	0.10 no ignition	0.4	0.37	0.50	3 loops $\sim 4.2 \times 10^{-5}$	0.90	2.2×10^{-9}	3L
					2 loops $\sim 4.6 \times 10^{-6}$	0.10		
					+ failure	0.90	2.5×10^{-10}	2L
					CB $\sim 5.3 \times 10^{-4}$	0.99	3.1×10^{-8}	CB
					loss of no, 1 or 2 loops ~ 1	0.01		
				0.50				
			0.63					
		0.6 new release	0.37	0.50	3 loops $\sim 4.2 \times 10^{-5}$	0.90	3.4×10^{-9}	3L
					2 loops $\sim 4.6 \times 10^{-6}$	0.10		
					failure	0.90	3.6×10^{-10}	2L
					CB $\sim 5.3 \times 10^{-4}$	0.99	4.7×10^{-8}	CB
					loss of no, 1 or 2 loops ~ 1	0.01		
				0.50				
			0.63					
	0.40 torch							

$$\begin{aligned} \sum 3L &= 3.2 \times 10^{-8} \\ \sum 2L &= 3.4 \times 10^{-9} \\ \sum CB &= 4.4 \times 10^{-7} \end{aligned}$$

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LOSP and failure of the third loop. Containment building damage can be characterized as a hole in the containment, by a VCE, with falling concrete damaging the core cooling systems located inside. The loss of no, one or two loops does not lead to core heatup and encompasses any damage to the plant that does not prevent core cooling.

The calculation of the probabilities associated with these types of damage are simple, but involved. A sample calculation is given in Table 8-2, outlining the calculation of the probability of losing the two UHS heat exchangers located in adjacent buildings and losing the third loop, leading to a core heatup sequence being initiated. For a given sequence of branches in the event tree, the size of the released cloud can be estimated which constitutes the starting point for calculating the probability of damage.

For this analysis a reference site was needed in order to enable frequencies to be assigned to the six Pasquill stability classes (Ref. 14). In this study Morgantown, West Virginia, the proposed SRC II site, was used. The atmospheric conditions determine the drift, lift (or buoyancy) and diffusion of the cloud; so each branch must be evaluated under each of the six stability classes. For the branch we are considering in this example, only stability class C leads to a cloud which has the potential to damage the two UHS heat exchangers. For that stability class and the estimated size of the cloud, an angle around the UHS structure in which the center of the cloud must be in order to damage the fans can be determined. In this analysis a random wind direction is assumed since the relative location and orientation of the nuclear plant-reformer complex has not been firmly established yet. Thus, the probability of the cloud being within that angle is just that angle divided by the angle in which the cloud must be over the plant in order to damage the plant. This probability, based on the angle of cloud emission, is due to the fact that in a previous branch of the event tree we already took into account the fact that the wind might blow the cloud away from the nuclear plant. Next, a probability must be given for ignition of the cloud. There are two factors to be considered

TABLE 8-2

PROBABILITY BREAKDOWN OF DAMAGE TO PLANT FOR
LOSS OF 2 UHS HEAT EXCHANGERS

STABILITY CLASS

Probability of stability class C occurring = 0.0877

WIND DIRECTION

For given stability class and cloud size:

Half angle for damage = 32°

Total angle cloud must be in = 135°

Probability of wind direction being one that causes damage = 0.48

IGNITION SOURCE

Probability that cloud will not ignite at point of release = 10^{-1}

Probability that cloud will ignite during flight while in region of damage = 10^{-1}

TOTAL PROBABILITY OF IGNITION OCCURRING AT A TIME WHEN DAMAGE CAN OCCUR = 10^{-2}

TOTAL PROBABILITY OF REMAINING CACS LOOP FAILURE = 10^{-2}

TOTAL PROBABILITY OF DAMAGE = $(0.48)(0.0877)(10^{-2})(10^{-2}) = 4.2 \times 10^{-6}$

here: the probability that the cloud will not ignite at the point of release and the probability that the cloud will ignite while over the UHS and in a region where it could cause damage. These probabilities are estimated from information on drifting vapor clouds in the literature and are independent of the probability of ignition. A probability must also be assigned to the failure of the other, undamaged CACS loop. This estimate comes from information in the AIPA study on failure of CACS loops after operating for a period of time. It is very likely that the lone CACS loop will be depended upon for core cooling for quite some time, because of all the repairs necessary in the process plant and repairs needed in the other, damaged CACS loops. The total probabilities of damage leading to initiation of a core heatup sequence is given by the product of all these probabilities.

These calculations include many factors both measurable and unmeasurable. The estimates of each probability were made as realistically as possible based on the information available. It is recognized that there are uncertainties in the estimates, but a full scale uncertainty analysis was outside the scope of this study. Some uncertainties in the probabilities were, instead, estimated for the final result and are included in the risk plot.

9.0 RISK PLOT

The assigned probabilities per reactor year for the core heatup branches of the event tree were summed according to the types of damage to the plant (3 loop, 2 loop + failure, or containment) and are displayed on a risk plot in Figure 9-1. The consequences for these sequences were scaled from similar core heatup sequences for the HTGR-SC (steam cycle). The 3L and 2L + failure points were scaled with reactor thermal power from point CH-4 on the risk plot for core heatup with eventual containment failure by overpressurization due to accumulation of non-condensable gases. The CB point was scaled with reactor thermal power from point CH-1 for core heatup without containment isolation. This risk plot shows median point estimates for various core heatup sequences considered in the AIPA study (Ref. 15) and median point estimates for the three damage categories considered in this study. The other darkened lines are limit lines for the quantitative safety goals (Ref. 16) for an emphasized risk policy (with a simplifying assumption that mean/median is 2). Risk curves for LWR's and probable safety goals for LWR's are less restrictive than these proposed goals by several orders of magnitude. The dashed lines across at a probability of 10^{-6} is a licensing line used to determine the limit of events to be studied for licensing purposes. The larger, darkened triangles labeled with 3L, 2L + failure and CB represent the summed probabilities for three loop damage, two loop damage + failure of the third, and containment building damage, respectively. The open triangles above each of these represent where the point estimate would be if the event trees for the other initiating events were the same as for compressor failure (which may not be the case).

Uncertainty bars were shown on each of the three point estimates on the risk plot in order to indicate, qualitatively, the uncertainties incurred in the estimates. For the 2L and 3L points, the uncertainty bars extent one order of magnitude in both directions. This uncertainty is due to two factors: sensitivity of the results to the cloud height model (a decrease in cloud height of fifty percent could give frequencies an order

Figure 9-1

LEGEND

- ▲ - 3000MW(4) Core Heatup Categories
 CH-1 non-isolated containment
 CH-2,3 immediate heatup with long term containment failure
 CH-4,5 same as CH-2,3 but delayed heatup
 CH-6 intact containment

- ▨ - 1170MW(4) PH Core Heatup Categories
 CB initially failed containment and loss of core cooling
 3L VCE damage to 3 CACS loops and long term cont. failure
 2L VCE damage to 2 CACS loops and failure of third loop and long term containment failure

△ - point estimate including other initiating events, assuming similar frequencies and consequences

Median Probability Per Reactor-Year

of magnitude higher) and the uncertainties in estimating the other, less sensitive probabilities. For the CB point, the uncertainty band extends an order of magnitude in the increasing frequency direction and more than an order of magnitude in the decreasing frequency direction. The single order of magnitude uncertainty is due to the same factors as mentioned for the 2L and 3L cases, but the increase in uncertainty in the decreasing frequency direction is due to another factor. With the cloud models used in this study, the only size cloud which could cause containment building damage is cloud of 100 lbs; and since the entire contents (6000 lbs) of a damaged reformer train would be expelled after any accident, there is uncertainty as to how a cloud of only 100 lbs is formed. It must be emphasized that these uncertainty estimates are just that, estimates. No attempt was made to quantitatively determine the uncertainties since it was outside the scope of this study.

The point estimates for all three core heatup categories fall well below LWR risk curves, and all three point estimates fall within the licensing limit line. The 3L and 2L points and uncertainty bands also fall within the safety goals and would have little effect on the overall risk curve for the plant. The CB point, however, lies close to the limit line and its uncertainty band extends up into the unacceptable region and above the licensing limit line. The CB point would also be expected to slightly raise the overall risk curve for the plant. It must be stressed, however, that none of these points are significantly different than the other core heatup points for a HTGR-SC. This result is quite encouraging.

10.0 POSSIBLE DESIGN MODIFICATIONS

The fact that the plant design is at a very early stage has advantages and disadvantages in a study of this type. First, it allows input in the early stages of the design process should any of the results from this study suggest that design changes might be necessary. Second, it forces the people working on the study to make assumptions without assurance that the final design will be able to satisfy the assumptions. Assumptions made in this study have been mentioned throughout this report and are detailed in Appendix A, but there is one more assumption that should be addressed here. That is, the assumption was made that all possible ignition sources would be eliminated from the top of the containment. This assumption greatly reduces the chance that a VCE would occur while the containment dome is being engulfed by a vapor cloud. Therefore, the PRA results require elimination of these ignition sources from the top of the containment.

Changes in the plant which would reduce the risk of the CB point on Fig. 9-1 do not appear justified because the points for CH-5 and CH-3 provide similar risk. However, if the plant design is changed, such as by the adoption of enhanced safety features, and the risks from CH-3, CH-4, CH-5, and CH-6 are thereby reduced, then a design change to reduce the risk of point CB should be seriously considered. One such change is evident as a result of this study but the change may be accomplished in either of two ways. First, move the entire reformer train another 200 ft from the containment (this has adverse effects on the performance of the NHS). Or second, move the reformer train, except the reformer, another 200 ft away. The second alternative would probably be performed because it would have virtually no impact on plant performance. Either of these alternatives would result in most of the released vapor clouds being much higher by the time they approach the containment and would thereby reduce the probability that a VCE could damage the containment.

Two design changes greatly reducing the probability that a single VCE could damage both the diesel coolers and cause LOSP include splitting the triple DCFSB into three single DCFSB with a minimum separation distance of 500 ft and separating the DCFSB and all equipment associated with offsite power greater than 600 ft, but the risk is already low for damage of this type and these changes are not necessary at this time. Splitting the double UHS would reduce the probability that two loops could be damaged such that a core heatup was initiated, thereby lowering the two loop (2L) point on the risk plot. This suggested design change, too, is not necessary at this time since both the 2L and the 3L points are very low on the risk plot. Another possible design change, removing the walls and roof around the reformer train buildings, would be done, primarily, to reduce investment risk. By enclosing the reformer train a blast is very likely once flammable gas is released, leading to extensive damage to the expensive reformer train. Elimination of the roof and walls would greatly reduce this chance, while not affecting the plant risk.

A summary of these possible design modifications is given in Table 10-1.

TABLE 10-1
DESIGN MODIFICATIONS

REQUIRED FOR VALIDITY OF ANALYSIS

- o Eliminate all ignition sources from top of containment

POTENTIAL CHANGES IF ENHANCED SAFETY FEATURES ARE ADOPTED

- o Move entire reformer train another 200 ft from containment (this alternative has adverse effects on NHS performance)
- or
- o Move reformer train (except reformer) another 200 ft from containment

CHANGES WHICH APPEAR UNNECESSARY FOR SAFETY

- o Splitting triple DCFSB into three single DCFSB's with minimum separation of 500 ft, possibly combining UHS and DCFSB
- o Separating DCFSB and all equipment associated with offsite power greater than 600 ft
- o Removing walls and roof around reformer train (investment risk)
- o Splitting double UHS structure into two single UHS structures with a separation distance of greater than 500 ft

11.0 CONCLUSION

The results of this preliminary probabilistic risk assessment of the 1170 MW(t) HTGR-PH (reformer) plant shows that the risk to the public due to the addition of the reformer train are not significantly greater than those risks already associated with a HTGR-SC plant. The risks associated with the plant fall far below the risks for LWR's, exhibiting the HTGR superiority in process plant applications. This conclusion is, however, obtained from preliminary results and further study would be needed to explore all the facets of the very complex problem of VCE's in nuclear plants. Further study is also needed to assure that the other initiating events do not pose significantly greater hazard to the nuclear plant including explosions within the reformer. Additional work should also be done to accurately evaluate the uncertainties associated with the methods used in this study and to do an uncertainty propagation analysis in order to bound the range of predicted values.

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APPENDIX A

ASSUMPTIONS MADE ABOUT THE DESIGN OF THE PLANT

In order to do a PRA on this type of plant, many details not included in the early stages of the design must be known. In particular, since the present design of the process plant has too little detail for this type of study; then many assumptions had to be made. Also in the nuclear plant, there are areas in which the design of the HTGR-PH has not progressed to a point of adequate detail. Since the results of this study depend upon these assumptions, the reasoning and thought behind each assumption must be documented. It is the purpose of this appendix to present the design assumptions made in this preliminary PRA study and to, also, present some background as to why these assumptions were made.

Nuclear Plant Design Assumptions

As mentioned earlier in the report, the basic design for the plant was taken from United Engineers and Constructors' plant drawings (Ref. 1). Those drawings included a plot plan of the plant, general arrangement diagrams of the containment, containment penetration building, and reactor service building at two different elevations, a general arrangement elevation diagram of the containment, general arrangement diagrams of the turbine building (floor plan and elevation view), general arrangement diagrams of the reformer train buildings (floor plan and elevation view), a heat balance diagram, and a key one line diagram of the unit electrical distribution. The plot plan was used to determine the relative position of the various plant buildings. Distances for cloud travel and distances for blast overpressure calculations were taken for the plot plan, also. The details of nuclear plant building design were assumed to be the same as for the 900 MW(e) HTGR plant, since that design had the most detail and was similar in layout to the process heat plant. The topography of the site was assumed to be flat in order to simplify calculations of cloud height. This is probably a fair assumption since many nuclear plants are layed out on level sites.

Two assumptions were made about the operation of the nuclear plant during process plant accidents. First, it was assumed that main loop cooling is lost when an accident occurs in the process plant area. This assumption is a logical one since, when an accident occurs in the process plant, combustible gas is being released in the reformer train area, and rather than risk further releases of combustible gas, it makes sense that the process would be shutdown immediately after the accident is discovered. This means that the nuclear plant will be reliant upon the core auxiliary cooling system (CACS) for core cooling. The second assumption was that the CACS would not have been put into operation before the damaging VCE occurs. This assumption also seems correct, because it only takes about a minute for a vapor cloud to reach the nuclear plant after it has been released and it is unlikely that the release would be detected and the CACS started within that time.

Process Plant Design Assumptions

Unlike the nuclear plant where many designs of similar plants have been developed in great detail, the process plant is a new design and consequently there were many more design assumptions made. The basic design for the process plant comes from the UE&C drawings of the reformer train buildings (drawings SK-153 and SK-154). These drawings show only the largest components and include very little detail, even in such areas as piping. The first, most general, assumption made was that the components used in the process plant were not made of nuclear grade materials. This assumption was made because of the fact that the components in the reformer train are not nuclear safety related and, therefore, it would not be necessary to require the more expensive nuclear grade materials. This assumption is important because failure rates for non-nuclear grade components are generally higher than those for nuclear grade components. The assumption was also made that the reformer train buildings would be made with sheet metal type walls and roof, similar to the Fort St. Vrain design. This assumption, also, is because the reformer train is not considered nuclear safety related and therefore would be required to be

enclosed in reinforced concrete. Another general assumption for the reformer train was made about the maintenance on the four reformer trains which would be done at the same time. That is, there would never be maintenance done on one train while the other trains were operating. Once again, the fact that combustible gases are in use in the process plant would seem to dictate that all maintenance be done at the same time, in the absence of combustible gases. Maintenance in the reformer train area during operation would not only increase the chance of gas being released (because of accidents), but also it would increase the chance of finding an ignition source for the combustible gas.

Other, less general, assumptions on design details were also necessary for the present study. One such assumption was that the pipelines that link the nuclear plant (reformer train) to the surrounding user plants, would be routed such that the closest approach to any safety related nuclear plant structure would be at the reformer train buildings. This assumption was made for two reasons: first, the nuclear plant and process plant would probably be designed such that the reformer train would be positioned as close to the user plants as possible, thus justifying the assumption made; second, by designing the piping in this way it greatly reduces the risk to the nuclear plant by moving a potential source of combustible gas as far from the nuclear plant as possible. Another assumption made about these pipelines was that they would have automatic isolation valves within the nuclear plant boundary to cut off the flow of methane and synthesis gas between plants. Presumably, there would be an isolation valve at the nuclear site boundary on each of the pipelines going to the four reformer trains. The further assumption was made that those lines would be combined into two single pipelines before they left the nuclear plant and that there would be an isolation valve on each of them. It was also assumed that all the piping within the reformer train buildings would be overhead because of the space limitations imposed by enclosing the reformer train components in buildings. From the reformer train layout and the process heat balance it is clear that the piping within each building will be both considerable and complex. Much of this piping is associated

with the compressors and inter-stage coolers for the compressors. One additional assumption made about the compressors was that during normal operation, one of each of the two sizes of compressors would not be in use and would serve as a backup. This assumption was made because it was felt that an extra compressor would be supplied so that the process could continue at full flows even if one compressor was down. Because those compressors would have to be valved into and out of service, it was assumed that there were approximately two valves per compressor in each reformer train. Each reformer train building has eleven ventilation fans on the roof of the building. For some of the calculations on combustible gas accumulation it was necessary to estimate the circulation rate of those fans. This estimate was done by making a rough measurement of the size of the fan from the plant diagrams and checking the flow rate for a comparable size fan in equipment catalogs. The circulation rate for each fan was estimated to be approximately 20,000 cfm. Another assumption made about the reformer train was that the reformers must have pressure relief valves on them, although they were not shown in the UE&C drawings. Putting relief valves on large reactor vessels, such as reformers, in order to prevent vessel overpressurization is common practice in the chemical industry. Because these relief valves are a potential source of combustible gas, it was assumed that all relief valves would be vented into a separate piping system and sent to a flare some distance away as it is common practice in the chemical process industry.

In order to estimate the mass of released clouds, it was necessary to calculate the inventory of gas in a reformer train. This calculation was done by, first, estimating the volume of all the vessels in a single reformer train from the plant diagrams. From these volumes and with the knowledge of the pressure, composition and temperature of the gases inside the vessels, it was possible to calculate the amount of gas contained in each reformer train. Since the only isolation valves for each reformer train are at the plant boundary, it was necessary to estimate the volume of all the piping (including the piping to the plant boundary). From that volume and similar knowledge of the process operating conditions, the

amount of gas in the piping was calculated. Those quantities were summed and used as an approximate maximum mass for released clouds. This method was very approximate, but the analysis is not sensitive enough to cloud size to require a precise calculation of the amount of gas present. The maximum mass of the cloud used was 6000 lbs.

APPENDIX B

ESTIMATION OF EVENT TREE PROBABILITIES

The purpose of this appendix is to provide documentation of the methods used in estimating the frequencies and probabilities in the event tree used in this study. A great deal of groundwork was done before probabilities were ever estimated and it is hoped that the important information pertaining to those probabilities can be passed on in this appendix. The event tree used in this study is shown in Figure 8-1. This appendix will go through the event tree column by column, explaining the estimate of the probabilities shown in each branch.

The first frequency included in the tree is the frequency of the initiating event, in this case a compressor failure. This frequency comes from data supplied by the Canvey Island Study (Ref. 7). The other initiating event frequencies listed in the body of the report came from Canvey Island and the GCR Databank (Ref. 8) for components generic to all power plants. As mentioned in Appendix A, one of the design assumptions of this study was that the components in the reformer train were not made of nuclear grade materials. These frequencies are for similar components, in similar operating conditions and are consequently applicable to our study.

The probabilities designed to the different ways the gaseous release behaves, as far as combustion is concerned, must be examined next. From literature (Ref. 17), it is found that a release of combustible gas has a probability of not igniting equal to 0.10; this accounts for the branch labeled "no ignition". The literature (Ref. 17) also states that the probability of deflagration (i.e. slow-combustion or burning accompanied by radiant heat but without pressure wave) after successful ignition is nearly equal to the probability of detonation after successful ignition for unconfined vapor clouds. For a release of this type, within a building, the probability of detonation must be taken as being higher than the probability of deflagration since it is a confined vapor cloud. For this

reason, the probability of deflagration (branch labeled "torch") was chosen to be 0.40. This means that the probability of detonation is 0.50. However, after a detonation, the following release from the reformer train may behave in two different ways, that is it could burn as a torch, or it could continue to be expelled, unburned (similar to what occurs when explosives are used to extinguish an oil well fire). It was assumed, since there would probably be extra ignition sources due to the blast damage, that the probability of the release burning as a torch after detonation would be approximately twice the probability of the release continuing unburned. This assumption leads to probabilities of 0.35 and 0.15 for detonation with torch and detonation without torch, respectively.

If an explosion occurs, there is a probability that the adjacent reformer train buildings could be damaged, releasing more combustible gas. For an explosion without a subsequent torch there are two ways the adjacent reformer buildings could be damaged as already mentioned in Section 5.0. That is, by the initial blase (first release), or by an explosion from the unburned gas being expelled from the train (new release). The probability of the adjacent reformer train buildings not being damaged was assumed 0.10. This assumption is because, for the amounts of gas being considered, the blast effects in the near field would be appreciable. Further, the probability that the adjacent buildings would be damaged by the initial blast was assumed twice the probability that the new release would damage them. This assumption is due to the fact that the new release could be blown away from the reformer buildings before it ignites and there is also some chance that the release may never ignite (or detonate). For detonation with a torch, the same assumptions were made. That is, the probability of no damage to adjacent buildings is 0.10 and, since there is no other source of unburned gas, the probability of the initial blast damaging the adjacent buildings is 0.90. For a release that has escaped the building without igniting, the probability of not damaging the adjacent reformer train buildings is estimated to be 0.40. This probability is associated with the fact that the wind could be blowing the release away from the adjacent buildings and the consideration that, since the gas has

not found an ignition source inside the building, the probability that it finds one outside the building is much less. This leads to a probability of 0.60 for the release damaging the adjacent reformer buildings.

At this point in the event tree, the probabilities have been estimated for a release of combustible gas to the atmosphere occurring in the reformer train area. The direction of the wind need be considered in estimating the probability that this cloud could damage the nuclear plant. For this reason, a probability was estimated for the wind blowing a cloud, released from the reformer train area, toward the nuclear plant. This probability was estimated by assuming no preferential wind orientation, which means the quotient of the angle covering the area of damage by 2π , i.e., a geometrically defined probability. Thus, the prevailing winds were not considered and, for the cloud sizes considered in this analysis, the limits of the wind direction covering the area of damage were taken as the limits of the range of angles containing clouds which could damage the nuclear plant. Damage to the nuclear plant, is considered to be any damage to plant components or systems such that a core heatup sequence could be initiated. The range of the clouds that could cause damage was found to be within an angle of 135° . For a randomly oriented wind (i.e., wind without preferential orientation) the probability that the cloud moved toward the plant would then be 135 divided by 360 or 0.37.

If a combustible cloud is over the area where it could damage the nuclear plant, then a probability must be assigned to account for the chance that the cloud could detonate. According to the literature (Ref. 17), for unconfined vapor clouds, the probability of detonation is approximately 0.50.

Once the probability of a VCE occurring over the nuclear plant has been determined, it is necessary to determine whether the damage, if any, initiates a core heatup sequence. For this determination, the damage to the plant was divided into four categories: loss of three CACS loops, containment building damage and loss of three CACS loops, loss of two CACS

loops and failure of the third, and loss of no, one, or two loops. The breakdown of these categories is given in the body of the report. An example of the calculations, with an explanation, for one of these branches is also given in the report. Therefore, elaboration on the calculation of each branch will not be given, as each branch uses a similar logic. A listing of the probabilities used in the calculation of the branches is given in Table B-1. The probabilities for each category of damage are assumed to be approximately the same throughout the event tree. This assumption can be made because the size of the cloud and the mode of release have little influence on the probabilities used in the calculations. The range of cloud sizes is relatively limited, due to the limitation on the amount of gas released which is imposed by the closing of the isolation valves. In case of failure of the isolation valves, the increased size of the cloud would only decrease the probability of damage. This fact is because larger clouds rise faster due to the increase in buoyancy associated with the increased mass, which prolongs its diffusivity in air. The influence of cloud size on rise rate is more pronounced in the case of containment building damage. The only size cloud which could damage the containment is a cloud of approximately 100 lbs. Because the small cloud rises slowly, at the point when the cloud reaches the containment it is approximately even with the top. Thus, if ignition were to occur leading to a cloud detonation, then the containment would be exposed to large detonation overpressures on the order of 300 psi, well above the structural limit of the containment. The fact that only clouds of approximately 100 lbs can cause containment damage, leads to the large uncertainty bars on the containment building damage point estimate used on the risk plot. Experimental data on detonating cloud masses indicates no references for 100 lb clouds (Ref. 17).

For a given type of damage, there is some probability that the damage could be repaired, and subsequent core cooling restoration, before reaching the PONR. For the three loop and two loop with failure of the third loop damage categories, this probability was estimated to be 0.10; giving a probability of 0.90 that the damage would result in a core heatup as shown

TABLE B-1

BREAKDOWN OF PROBABILITIES FOR DAMAGE TO PLANT

Event	Damage Category			Containment Building
	3 DCFSB + LOSP	2 DCFSB + LOSP + Failure of Other Loop	2 UHS + Failure of Other Loop	
Probability of stability class	0.0877	0.0877	0.0877	0.499
Angle of Damage (135°)	0.48	0.48	0.48	0.106
Probability of ignition at time when damage could occur	10^{-2}	10^{-2}	10^{-2}	10^{-2}
Probability of Damaging OSP equipment with same blast	10^{-1}	10^{-1}	--	--
Probability of failure of remaining loop	--	10^{-2}	10^{-2}	--
TOTAL	4.2×10^{-5}	4.2×10^{-7}	4.2×10^{-6}	5.3×10^{-4}

$$3L = 4.2 \times 10^{-5}$$

$$2L + \text{Failure} = 4.2 \times 10^{-7} + 4.2 \times 10^{-6} = 4.6 \times 10^{-6}$$

$$CB = 5.3 \times 10^{-4}$$

in Fig. 8-1. For the containment building damage category, the probability of repair was estimated to be 0.01. The more extensive damage represented in this category justifies the lower probability of repair.

The total probabilities for each sequence leading to core heatup and fission product release are shown adjacent to the appropriate sequence at the right of the completed event tree shown in Fig. 8-1. These probabilities were calculated by taking the product of all the individual probabilities for each sequence. The total probabilities of fission product release due to each of the three categories of damage are shown at the bottom of the tree. These total probabilities were calculated by summing the individual total probabilities for similar sequences. These total probabilities were later used as median point estimates of the frequencies of the corresponding core heatup sequences. The consequences for these point estimates were scaled from similar sequences in the AIPA study (Ref. 15). The consequences for the three loop damage (3L) and two loop damage and failure of the third (2L + failure) points were taken from core heatup and eventual containment overpressurization sequences in the AIPA study and scaled in accordance with the reactor thermal power to correctly represent the total fission product inventory. The consequences for the containment building damage (CB) point was taken from a core heatup and failure of containment isolation valves sequence and was also scaled with reactor thermal power to represent the fission product inventory.

APPENDIX O

APPENDIX 0

HTGR PROGRAM

ECONOMIC GUIDELINES

Research and Engineering
Bechtel Group, Inc.
San Francisco, California

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ABSTRACT

This paper explains the methodology and input necessary to determine the annual or levelized revenue requirements for a firm's anticipated expenditures for a specified capital investment. This method does not evaluate the profitability of a given project based on the product's market price. Instead, it determines the annual or levelized cost of energy production based on the firm's financial requirements and anticipated operating expenses.

A discussion of the uses of constant and inflated dollars is included. Bechtel recommends that all studies for the GCRA project be performed in constant dollars. The derivation of both methods is included for reference.

Typical rates of return and financial structures are recommended for use in generic energy planning or comparison studies. These rates are typical of an average regulated utility company or a publicly owned, nonregulated corporation that would typically own an energy complex. These rates should be used in all tradeoff studies for consistency.

Included in this paper, are examples of tradeoff studies which are based on both constant and inflated dollars. A method consistent with the constant dollar approach is recommended.

A glossary and details of the calculation methodologies are included as appendices for reference.

INTRODUCTION

The cost of energy can be determined by calculating the annual revenue requirements necessary to pay all expenses associated with producing energy over the economic life of the facility. Revenue requirements include two components: fixed costs, and variable costs. Fixed costs are those costs necessary to pay the obligations inherent in an investment decision. Variable costs include fuel expenditures, operating costs, and maintenance costs of the facility.

The revenue requirement of an alternative technology is the discrete charge associated with the alternative. It is used to determine the economic consequences of the alternative. The revenue requirement is not necessarily associated with the rates or prices charged by a company. Rather, it represents the minimum that a company must charge to undertake the alternative. Any lower charge would reduce the rate of return on invested capital received by the owners of the company and would prompt a decision not to proceed with the project.

Revenue requirement calculations can be performed in several different ways depending upon the requirements of the study. Comparisons can be made in constant dollar terms or inflated dollar terms (i.e., those costs that are generally expected to be experienced). Also, these comparisons can be expressed as annual revenue requirements or levelized revenue requirements. Each of these alternatives and their implications are discussed in this paper.

ESCALATION AND INFLATION

Inflation, or the change in the value of the dollar over time, greatly alters the revenue requirements over the life of an investment. Financial analyses can be performed in terms of constant dollars or inflated dollars depending on the requirements of the study.

The basic inflation dilemma is how to present the most comprehensible and useful result to the reader. When the analysis is carried out using inflated dollars, the resulting cost of energy over the life of the project is substantially greater than current market values, making it difficult to compare the present costs of competing fuels.

Alternatively, comparisons can be made in constant dollars, where the cost of energy can be directly compared against today's market value of energy. To do so, real rates of return on money are used to accurately perform the analysis. These values represent the acceptable returns to investors, anticipating no decrease in the value of returned money. Hence, the rates of return on invested capital appear inordinately low when compared with required returns during periods of high inflationary expectations. Thus, both approaches involve values not immediately recognizable and therefore potentially confusing to the reader. The two methods are equally accurate for decision-making purposes, when correctly applied. The difference between the results is in the magnitude of the cost of energy, rather than the relative rankings of the alternatives considered. The constant dollar approach is preferable because of the usefulness of comparing present costs of energy. The validity of the constant dollar approach for ranking alternatives has been proven in The Real Cost of Synthetic Fuels, B. M. Louks and M. I. Gluckman, Electric Power Research Institute, August 1980.

Associated with every revenue requirement calculation is a real escalation rate, an apparent escalation rate, an assumed inflation rate, and a discount rate. The real escalation rate is the annual rate of increase in a cost and is independent of, and in addition to, inflation. Real escalation results from resource depletion, increased demand with limited supply, etc. The apparent escalation rate, on the other hand, is the total annual rate of increase in cost. The apparent escalation rate includes the effects of inflation and real escalation. The apparent escalation rate (e), is described as:

$$e = (1 + e') (1 + i) - 1$$

e = apparent escalation rate

e' = real escalation rate

i = inflation rate

When determining levelizing factors and fixed charge rates, we need to know the firm's discount rate. The discount rate(r), or weighted cost of capital, is the annual rate representing the potential earning power of invested capital. This rate and the effects of inflation are used when dollar amounts are moved either forward or backward in time for comparison. In general:

$$r = (1 + r') (1 + i) - 1$$

r = discount rate
 (weighted cost of capital)
 r' = weighted cost of capital
 in the absence of inflation
 i = inflation rate

The important aspect of this is that if a study is made where inflation is neglected in future costs, inflation must also be neglected in the cost of money, and vice versa. Consistency between variables is essential in making proper investment decisions. This aspect is included in determining and using fixed costs, variable costs, and capital costs.

FIXED COSTS

In general, the annual revenue requirements associated with the fixed costs of a project are equal to:

$$\text{Capitalized Facility Cost} \times \text{Fixed Charge Rate}$$

This value is the annual cash inflow (revenue) necessary to pay for the use of the invested capital. If this value is returned every year during the investment, the firm would just recover its capital investment, along with the necessary rate of return on the invested capital.

Capitalized Facility Cost

Capitalized expenditures occur over the life of the planning, engineering, and construction phases of a project. Therefore, capital costs must be

adjusted to reflect the time sequence of anticipated spending. To do so, a detailed project expenditure schedule is usually assumed. In the absence of such a schedule, the center of gravity of expenditures at a point 70 percent through the project duration can be assumed. This value is considered typical for large energy projects, such as synfuel and electric power generation facilities.

In general, capital cost estimates are expressed in constant dollars without allowances for escalation during the construction period. However, to determine the capitalized value of the project, the apparent escalation of expenses during construction must be estimated. It will be necessary to estimate both real escalation of construction expenses, as well as future inflation rate trends.

Allowance for funds during construction (AFDC) is the carrying costs associated with borrowing money (either through outside financial transactions or through the use of retained earnings) to pay the expenses of the construction project prior to startup. For the investment analysis, the corresponding interest expenses are assumed to be capitalized at the point of the project startup. The AFDC rate (x) is defined as the after tax weighted cost of capital.

The capitalized value of the facility can be obtained when the escalated construction cost is combined with the interest expenses associated with the capital expenditure. In general, capitalized value is defined as:

$$(\text{Base } \$) (1 + e)^{0.7C} (1 + x)^{(1 - 0.7)C}$$

where:

Base \$ = $\frac{\text{Base \$ Estimate of construction costs}}{\text{Base \$ Estimate of owner's costs}} +$

Base \$ = Constant dollar estimate stated in a given base year (1981)

e = Apparent escalation rate on construction expenses

x = AFDC rate

= After tax weighted cost of capital (nominal terms)

0.7 = Center of gravity of capital expenditure

C = Project engineering/construction duration

This value reflects the total capital cost requirements in as-spent dollars. This is the actual dollar value which is expected to be paid out over the period prior to plant startup and would appear in the firm's initial balance sheet after plant startup.

In the case of real or zero inflation rates, the capitalized value can be found as follows:

$$(\text{Base \$}) (1 + e')^{0.7C} (1 + x') (1 - 0.7)C$$

where e' reflects the assumed real escalation rate in construction expenses, and x' is equal to the after tax weighted cost of capital in the absence of inflation. This value reflects the capital cost requirements expressed in constant dollars.

Financial Assumptions

Typical financial structures have been developed in Tables 1 and 2 to reflect the ownership of an energy facility by a regulated private power generating utility, or by a nonregulated public corporation, such as an oil company that typically owns a synfuel facility. Corresponding financial requirements are presented which represent values typical of those experienced in respective industries.

Two sets of assumptions are shown for each ownership scheme, based on two alternative economic criteria. Table 1 expresses the financing costs in real, or zero inflation rate, terms. These values are meant to reflect the real rates of return, over and above the underlying inflation rate anticipated by the investor. Historically, these values stay rather constant, with the change in market rates reflecting differing levels of inflationary expectations.

Alternatively, Table 2 expresses the financing costs in market, or inflation adjusted, terms, based on an 6 percent underlying inflation rate. Six percent is meant to be a typical estimate for the underlying inflation rate, but is not a forecast of future inflation trends. Allowances for investment tax credits have been specifically excluded from this analysis because the law's applicability is uncertain. Use of the retirement dispersion allowance is also excluded.

Table 1

FINANCIAL ASSUMPTIONS
ASSUMING ZERO INFLATION RATE

	<u>Regulated Utility</u>	Public ⁽¹⁾ <u>Corporation</u>
<u>Capital Structure %</u>		
Debt	50	25
Preferred Equity	15	-
Common Equity	35	75
<u>Financing Costs %</u>		
Bond Yield	3.1	4.1
Preferred Equity Yield	4.1	-
Common Equity Yield	5.9	8.5
Weighted Cost of Capital	4.3	7.4
Property Taxes and Insurance	2.0	2.0
Effective Tax Rate	50.0	50.0
AFDC Rate	3.5	6.9
Resulting Fixed Charge Rate	8.3	13.2
Plant Investment Life (Years)	30	30
Plant Tax Life (Years)	20	20
Depreciation Method	Accelerated SYD	Accelerated SYD

(1) A company such as Exxon.

Table 2

FINANCIAL ASSUMPTIONS
ASSUMING 6% INFLATION RATE

	<u>Regulated Utility</u>	<u>Public⁽¹⁾ Corporation</u>
<u>Capital Structure %</u>		
Debt	50	25
Preferred Equity	15	-
Common Equity	35	75
<u>Financing Costs %</u>		
Bond Yield	9.3	10.4
Preferred Equity Yield	10.3	-
Common Equity Yield	12.3	15.0
Weighted Cost of Capital	10.5	13.9
Property Taxes and Insurance	2.0	2.0
Effective Tax Rate	50.0	50.0
AFDC Rate	8.2	12.6
Resulting Fixed Charge Rate	15.3	22.2
Plant Investment Life (Years)	30	30
Plant Tax Life (Years)	20	20
Depreciation Method	Accelerated SYD	Accelerated SYD

(1) A company such as Exxon.

The fixed charge rate represents the percentage of the plant's capitalized value that must be recovered yearly, in revenues, over the investment life to meet the firm's required return on capital. The fixed charge rate includes the percentage of return on invested capital, as well as a capital recovery portion and the funds necessary to pay income taxes. An allowance for plant insurance is also included.

Fixed charge rates have been calculated based on the two alternative ownership schemes and two assumptions about inflation. The specific derivation of the fixed charge rate is developed in Appendix B.

VARIABLE COSTS

Variable costs, also called operating costs, consist of fuel expenses plus operating and maintenance (O & M) expenses. Total variable costs can be determined by estimating the annual O & M and fuel requirements based on the anticipated annual energy production, assuming a given capacity factor and the design rating of the facility.

The annual revenue requirement associated with a given technology must be adjusted from the estimated base cost to the initial year of operation.

This adjustment can be made as follows:

$$(\text{Variable Cost } \$) (1 + e)^D$$

where:

e = Apparent escalation trends associated with the O&M and fuel expenses

D = Duration between the cost estimate of variable costs and initial operation (expressed in years)

It is important to realize that variable costs will also escalate over the life of the facility. To account for this, we have the option to express the revenue requirements associated with these expenses in either year-by-year terms, or in levelized terms.

To determine the total year-by-year revenue requirements, the levelized fixed charges are added to the year-by-year escalated value of variable costs. A comparison of these values is best expressed in graphic form when comparing between alternatives.

The problem with year-by-year requirements is that these values do not reflect the firm's cost of money. In other words, a dollar spent today is not equivalent to a dollar spent tomorrow, given a firm's cost of utilizing capital. For the sake of comparison, we can levelized these yearly requirements by multiplying the present worth of these expenditures by the firm's capital recovery factor.* By levelizing, the anticipated escalating stream of expenses can be reduced to a single value which, when combined with the levelized fixed costs, yields a value for the cost of energy production.

LEVELIZED COST OF ENERGY

To determine the total cost of energy production, add the revenue requirements associated with the levelized fixed costs (capitalized investment $\times$ FCR) and the levelized variable costs (variable costs $\times$ LF) over the life of the investment. These revenue requirements are shown in Table 3.

Through the levelizing process, we are able to reduce all of the cost information available to a single value of merit which, when compared against alternatives, yields relative financial consequences between alternatives. Since the levelized revenue requirements method incorporates all of the anticipated expenditures over the life of the investment, it is the recommended method to compare technologies with similar functions and economic lives. This permits a decision of the preferred choice among alternatives, based on a given set of common assumptions.

* See Appendix C for the derivation of the Levelizing Factor (LF).

TABLE 3
REVENUE REQUIREMENTS

This levelized cost of production calculation can be made in both constant dollar terms, expressed in base year dollars, or in inflationary terms, expressed in as-spent dollars. Either value can be used effectively to compare alternatives, and the choice of either one depends on the requirements of the study.

In many instances, it is necessary to calculate the levelized cost of energy, expressed in terms of \$/unit of production. This value is determined by dividing the levelized revenue requirements by the annual energy production. In general, this value can be determined as follows:

$$\text{Levelized Cost of Energy} = \frac{\left(\frac{\$ \text{ Capitalized Investment} \times \text{FCR}}{\text{Levelized* Capacity Factor}} \right) + \left(\frac{\text{Annual Variable Costs} \times \text{LF}}{\text{Total Energy Production at Design Capacity per Year}} \right)}{1}$$

COMPARISON OF ALTERNATIVE GENERATING SOURCES

As noted earlier, the levelized revenue requirements are equal to the sum of the levelized fixed costs associated with the capitalized value of the investment plus the levelized variable costs. Once these two costs have been calculated, they should be added together for each alternative. The alternative with the lowest total revenue requirement should be selected.

This energy cost calculation is a useful means of comparing the economic consequences of energy generating/producing alternatives in a simplistic, yet consistent manner. It is a convenient concept that condenses the cost information into a single figure of merit, offering decision makers an easy mechanism to perform comparisons between alternative technologies or processes. It should only be used when comparing like functions and technologies.

*See Appendix D.

Two example calculations of differential revenue requirements follow. Example 1 is performed in constant dollars, and Example 2 in inflated dollars. Assuming that both methods yield consistent results, Bechtel recommends that constant dollar analysis be used. In either case, the most important aspect is to be consistent in the use of escalation rates and rates of return. Prior to calculation, all costs must be adjusted to a consistent dollar value, either in base year cost or in dollar requirements in the initial year of operation. Once these values are determined, consistent financial assumptions must be used.

Economic Evaluation Methodology Example 1

Constant Dollar Case

This example illustrates the revenue requirements method Bechtel proposes to use in this study for the economic evaluation of alternatives in plant design. Regulated utility financial assumptions are used.

Problem

Compare two plant design alternatives to determine the most economic alternative. The plant characteristics are:

	<u>Case 1</u>	<u>Case 2</u>
Base year capital cost (\$/kWe)	Base	+ 50
Base year O & M cost (\$/kWe)	+ 5	Base
Net plant heat rate (Btu/kWh)	9,000	8,800

Common Cost Factors

Financial criteria	constant dollars	
Plant economic life	30 years	
Construction period	11 years	
Plant capacity schedule	year 1	40%
	2	50%
	3	65%
	4-30	70%
Weighted cost of capital	4.3%	
Levelized fixed charge rate	8.3%	
Allowance for funds during construction rate	3.5%	

	<u>Real</u>
Escalation rates - Construction	1%
- O & M	1%
- Fuel (Uranium, Coal and Oil)	3%
Levelizing factors - O & M	1.136
- Fuel	1.490
Fuel expense	\$0.70/MMBtu

Methodology

- Levelized Capacity Factor:

Due to the gradual increase in plant capacity over the initial operation of the facility, the capacity factor must be levelized over the life of the facility

Levelized Capacity Factor =

$$\left[40 \times P/F_{4.3,1} + 50 \times P/F_{4.3,2} + 65 \times P/F_{4.3,3} + 70 (P/A_{4.3,30} - P/A_{4.3,3}) \right] \times CRF_{4.3,30}$$

$P/F_{4.3,1}$ = Present worth of a future amount of 4.3%, 1 year

$P/A_{4.3,30}$ = Uniform series present worth for 4.3% and 30 years

Levelized Capacity Factor =

$$\left[40(0.96) + 50(0.92) + 65(0.88) + 70(16.68 - 2.76) \right] 0.06 = \underline{\underline{67\%}}$$

- Capitalized Cost Differential

$$\begin{aligned} &= \Delta \text{ capital cost } (1-e')^{(0.7)C} (1+x')^{(1-0.7)C} \\ &= \frac{\$50}{\text{kWe}} (1+0.01)^{(0.7)11} (1+0.035)^{(1-0.7)11} = \$60/\text{kWe} \end{aligned}$$

- Levelized Annual Capital Cost

$$\begin{aligned} &= \frac{\text{capitalized cost} \times \text{levelized annual fixed charge rate} \times 1,000}{8,760 \times \text{levelized capacity factor}} \\ &= \frac{60 \times 0.083 \times 1,000}{8,760 \times 0.67} = \frac{0.9 \text{ mills}}{\text{kWh}} \quad (\text{Penalty against Case 2}) \end{aligned}$$

- Escalated Fuel Cost

$$\begin{aligned} \text{Fuel Cost in Base } (1+e')^D \text{ Year Dollars} &= \text{Fuel Cost in Year of Operation} \\ = \$0.70/\text{MMBtu } (1.03)^{11} &= \$0.97/\text{MMBtu} \end{aligned}$$

- Levelized Annual Fuel Cost Differential

$$\begin{aligned}
 &= \text{fuel cost } (\$/\text{MMBtu}) \times \Delta \text{ heat rate (Btu/kWh)} \\
 &\quad \times \frac{\text{levelizing factor}}{1,000} \\
 &= \$0.97/\text{MMBtu} \times 200 \frac{\text{Btu}}{\text{kWh}} \times \frac{1.49}{1,000} \\
 &= 0.3 \frac{\text{mills}}{\text{kWh}} \quad \quad \quad (\text{credit to Case 2})
 \end{aligned}$$

- Escalated O & M Cost

$$\begin{aligned}
 \text{O \& M Cost in Base Year Dollars} (1+e')^D &= \text{O \& M Cost in Year of Operation} \\
 \$5/\text{kWe} \quad (1.01)^{11} &= \$5.58/\text{kWe}
 \end{aligned}$$

- Levelized Annual O & M Cost Differential

$$\begin{aligned}
 &= \frac{\text{O \& M cost}}{8,760} \times \frac{\text{levelizing factor}}{\text{levelized capacity factor}} \times 1,000 \\
 &= \frac{\$5.58/\text{kWe}}{8,760} \times \frac{1.136}{0.67} \times \frac{1,000}{1} = 1.1 \frac{\text{mills}}{\text{kWh}} \quad (\text{credit to Case 2})
 \end{aligned}$$

- Levelized Annual Busbar Cost

$$\begin{aligned}
 &= \Delta \text{ levelized capital cost} + \Delta \text{ levelized fuel cost} + \\
 &\quad \Delta \text{ levelized O \& M cost} \\
 &= <0.9> + 0.3 + 1.1 = 0.5 \frac{\text{mills}}{\text{kWh}}
 \end{aligned}$$

- Case 2 yields a levelized busbar cost of energy which is 0.5 mills/kWh less than Case 1 in constant dollars. Case 2 is, therefore, the most economical design.

Economic Evaluation Methodology Example 2

Inflated Dollars Case

This example illustrates an alternative revenue requirements method to use in this study for the economic evaluation of alternatives in plant design. Regulated utility financial assumptions are used.

Problem

Compare two plant design alternatives to determine the most economic alternative. The plant characteristics are:

	<u>Case 1</u>	<u>Case 2</u>
Base year capital cost (\$ kWe)	Base	+ 50
Base year O & M cost (\$/kWe)	+ 5	Base
Net plant heat rate (Btu/kWh)	9,000	8,800

Common Cost Factors

Financial criteria	inflated dollars		
Plant economic life	30 years		
Construction period	11 years		
Plant capacity schedule	year 1	40%	
	2	50%	
	3	65%	
	4-30	70%	
Weighted cost of capital	10.5%		
Levelized fixed charge rate	15.3%		
Allowance for funds during construction rate	8.2%		
	<u>Apparent</u>	<u>Inflation</u>	<u>Real</u>
Escalation rates — construction	7.06%	6%	1.0%
— O & M	7.06%	6%	1.0%
— Fuel (uranium, coal, and oil)	9.18%	6%	3.0%
Levelizing factors — O & M	2.108		
— Fuel	2.767		
Fuel expense	\$0.70/MMBtu		

Methodology

- Levelized Capacity Factor:

Due to the gradual increase in plant capacity over the initial operation of the facility, the capacity factor must be levelized over the life of the facility.

Levelized Capacity Factor =

$$\left[40 \times P/F_{10.5,1} + 50 \times P/F_{10.5,2} + 65 \times P/F_{10.5,3} + 70 (P/A_{10.5,30} - P/A_{10.5,3}) \right] \times CRF_{10.5,30}$$

$P/F_{10.5,1}$ = Present worth of a future amount of 10.5%, 1 year

$P/A_{10.5,30}$ = Uniform series present worth for 10.5% and 30 years

Levelized Capacity Factor =

$$\left[40(0.90) + 50(0.82) + 65(0.74) + 70(9.05 - 2.46) \right] 0.11 = \underline{\underline{65\%}}$$

- Capitalized Cost Differential

$$\begin{aligned} &= \Delta \text{ capital cost } (1+e)^{(0.7)C} (1+r)^{(1-0.7)C} \\ &= \frac{\$50}{\text{kWe}} (1+.071)^{(0.7)11} (1+.082)^{(1-0.7)11} = \$110/\text{kWe} \end{aligned}$$

- Levelized Annual Capital Cost

$$\begin{aligned} &= \Delta \frac{\text{capitalized cost} \times \text{levelized annual fixed charge rate} \times 1000}{8,760 \times \text{levelized capacity factor}} \\ &= \frac{110 \times 0.153 \times 1,000}{8,760 \times 0.65} = \frac{3.0 \text{ mills}}{\text{kWh}} \quad (\text{Penalty against Case 2}) \end{aligned}$$

- Escalated Fuel Cost

$$\begin{aligned} \text{Fuel Cost in Base Year Dollars } (1+e)^D &= \text{Fuel Cost in Year of Operation} \\ &= \$0.70/\text{MMBtu} (1.0918)^{11} = \$1.84/\text{MMBtu} \end{aligned}$$

- Levelized Annual Fuel Cost Differential

$$= \text{fuel cost (\$/MMBtu)} = \Delta \text{ heat rate (Btu/kWh)}$$

$$\times \frac{\text{levelizing factor}}{1,000}$$

$$= \$1.84/\text{MMBtu} \times 200 \frac{\text{Btu}}{\text{kWh}} \times \frac{2.767}{1,000}$$

$$= 1.0 \frac{\text{mills}}{\text{kWh}} \quad (\text{credit to Case 2})$$

- Escalated O & M Cost

$$\text{O \& M Cost in Base Year Dollars} (1+e)^D = \text{O \& M Cost in Year of Operation}$$

$$= \$5/\text{kWe} \quad (1.0706)^{11} = \$11.2/\text{kWe}$$

- Levelized Annual O & M Cost Differential

$$= \frac{\text{O\&M cost} \times \text{levelizing factor} \times 1,000}{8,760 \times \text{levelized capacity factor}}$$

$$= \frac{\$11.2/\text{kWe} \times 2.108 \times 1,000}{8,760 \times 0.65} = 4.1 \frac{\text{mills}}{\text{kWh}} \quad (\text{credit to Case 2})$$

- Levelized Annual Busbar Cost

$$= \Delta \text{ levelized capital cost} + \Delta \text{ levelized fuel cost} +$$

$$\Delta \text{ levelized O \& M cost}$$

$$= <3.0> + 1.0 + 4.1 = 2.1 \frac{\text{mills}}{\text{kWh}}$$

- Case 2 yields a levelized busbar cost of energy which is 2.1 mills/kWh less than Case 1 in inflated dollars. Case 2 is, therefore, the most economical design.

Appendix A

GLOSSARY

Accelerated depreciation. A tax preference allowance which accelerates the depreciation of invested capital. This will allow for lower income taxes being paid in the early life of the investment. There are two methods for determining accelerated depreciation that are allowed and commonly used; the sum-of-the-year's digits method, and the double declining balance switching to straight line method.

Allowance for funds during construction (AFDC). The interest paid on money used to construct an energy facility. AFDC is calculated over the time period from the start of the project until the commercial operation date. It is included as a separate cost account in the total capital requirements of the plant. The after tax cost of capital is used as the AFDC rate.

Apparent escalation (e). The total annual rate of increase in a cost. The apparent escalation rate includes the effects of inflation and real escalation.

As-spent dollars. The investment requirements expressed in inflated dollar requirements. This value reflects the actual cost incurred, including the effects of inflation and real escalation.

Availability. The actual period of time within the year in which a facility is available for operation.

Book Life. The average years of service expected from a piece of equipment before it is retired. Book life is used as a basis for depreciation accounting.

Capacity. The net production output for which an energy generating or producing unit is rated.

Capacity factor. The total generation divided by the product of the period hours and the unit capacity.

Capitalized value. The total capital outlay for a facility, including escalation during construction, allowance for funds during construction, owner's costs, etc. This value is the basis from which revenue requirements pertaining to the fixed costs are calculated. It can be expressed in real dollars or as spent dollars, depending upon the demands of the study.

Capital recovery factor. The percentage value applied against a given capital investment which equals the required rate of return plus a depreciation reserve sufficient to recover the invested capital at the end of the investment life.

Common stock cost. The weighted average return on all common stock issued by a corporation.

Common stock ratio. The amount of capital raised by the sale of common stock divided by the total amount of capital raised from the sale of preferred and common stocks and bonds by a corporation.

Commercial operation date. The date that a unit is declared to be available for regular production.

Cost of capital. The return required by investors for making investments, expressed as a percentage of the capital funds (debt, preferred equity, common equity).

Debt cost. The weighted average interest paid on all bonds or direct loan financing.

Debt ratio. The amount of capital raised from the sale of bonds and/or direct loans divided by the total amount of capital raised from the sale of preferred and common stocks, and bonds.

Depreciation. Charges made against income to provide for distributing the cost of the plant (less estimated net salvage) over the estimated useful life of the asset in such a way as to allocate it as equitably as possible to the period during which services are obtained from the use of facilities. This reduces the effective taxes paid on gross income.

Discount rate. The annual rate that is used to take into account the potential earning power of money while moving dollar amounts either forward or backward through time to a single point in time for comparison. The weighted cost of capital is used as the discount rate.

Energy efficiency. The ratio of the useful energy delivered by a system to the energy supplied to it.

Equivalent annual availability. The unit availability after considering the unscheduled partial and full outages plus those due to scheduled outages.

Financial instrument. Alternative methods of financing available to capital consumers. These instruments include bonds, preferred stock, and common stock.

First commercial service. The earliest time of initial services of a new technology that has been selected for commercial use and for which an order was placed on the date it was available for commercial orders.

Fixed charges or fixed costs. The annual costs associated with the ownership of property, such as depreciation, taxes, insurance, cost of capital.

Fixed charge rate. The amount of revenue per dollar of invested capital that must be collected for each year of plant life in order to pay the fixed charges.

Generating station (generating plant or power plant). A station at which are located prime movers, and/or electric generators, and auxiliary equipment for converting mechanical, chemical and/or nuclear energy into electric energy.

Heat rate. The amount of energy expressed in Btu's of higher heating value required to produce a unit of electricity expressed in kWh's.

Income tax rate. The percentage of gross income which must be paid to the government prior to income distribution to equity holders. This includes payment to both the federal and state governments, and is assumed to be 50 percent.

Inflation (i). The change in the value of the dollar over time. The combination of real escalation and inflation gives the apparent escalation.

Levelizing. The process of converting a time varying series of payments to an equivalent constant series. This is accomplished by multiplying the present worth of expenses by the capital recovery factor.

Levelized capacity factor. The capacity factor that an energy facility would run each year such that the present worth of each year's actual capacity equals the present worth of the levelized capacity factor over the same period.

Market rate of return. The rate of return on invested capital which is demanded in the market place. The investment community adjusts its required rate of return depending upon the perception of risk of a given financial instrument as well as because of anticipated changes in the inflation rate.

Owner's costs. Those costs which are experienced by the owner during the planning, engineering, and construction of a given facility. These values are assumed to be capitalized when considering an investment.

Planned outage rate. The rate for all planned or scheduled outage hours over a given service period of operation.

Preferred stock cost. The weighted average return on all preferred stock.

Preferred stock ratio. The amount of capital raised from the sale of preferred stock divided by the total amount of capital raised by the sale of preferred and common stocks and bonds by a corporation.

Rate of return. The percentage of capital which must be returned to the investor annually for the use of the invested capital. This return includes interest and dividend expenses as well as the appreciation on equity capital.

Real dollars. The investment requirements expressed in dollars of constant purchasing power. This cost reflects the changes as a result of real escalation, but excludes the effect of inflation.

Real escalation rate (e'). The annual rate of increase of a cost that is independent of and in addition to inflation. Real escalation results from resource depletion, increased demand, etc.

Revenue requirements. The annual revenue which is required in order to pay all of the expenses associated with a given investment. This can be described as the cost of production and is not necessarily associated with the actual revenues received based upon the market value of the product.

Risk. The perceived possibility of default of a given financial instrument. Rates of return are adjusted in response to this possibility of default to compensate for this risk.

Sinking fund. Cash and other assets, the interest or other income earned on such cash or assets set apart for the retirement of debt, the redemption of stock, or the protection of an investment in depreciable property.

Tax life. The number of years over which a piece of equipment is completely depreciated for tax purposes.

Tax preference allowances. Tax reducing incentives designed to encourage investment as a stimulus to the overall economy. These incentives include the use of investment tax credits as well as the use of accelerated depreciation.

Unscheduled outage rate. The rate for all full load outages that were not scheduled in advance. The unscheduled outage hours include the forced outage hours and the maintenance outage hours.

Variable costs. Those costs which vary with different levels of production. These costs generally include annual operating, maintenance, and fuel expenses.

Weighted cost of capital (r). The debt ratio times the debt cost plus preferred stock ratio times the preferred stock cost plus the common stock ratio times the common stock cost equals the weighted cost of capital.

Appendix B

ANNUAL FIXED CHARGE RATE

The fixed charge rate is the multiplier which, when applied to the initial plant capital investment, yields the levelized (average) annual revenue requirements associated with capital expenditures for the plant. When added to the annual fuel expenses and operation and maintenance expenses, yields the total annual revenues requirements. For comparison, both the subsequent year-by-year revenue requirements as well as the levelized revenue requirements must be examined. The revenue requirements for a capital investment include return, sinking fund depreciation, income taxes, and other taxes and insurance (fixed costs associated with capital expenditures).

RATE OF RETURN

The term "rate of return" is defined as the sum of returns to stockholders and bondholders. To compute this value, the weighted rate of return on both stock and bonds is used, and can be found as follows:

$$\begin{aligned}\text{Rate of Return} &= \text{Weighted Cost of Capital (r)} \\ &= (\text{Bond Yield} \times \text{Debt Fraction}) \\ &+ (\text{Common Stock Yield} \times \text{Common Fraction}) \\ &+ (\text{Preferred Stock Yield} \times \text{Preferred Fraction})\end{aligned}$$

Studies can be performed in either real terms (inflation free) or in market terms (the cost of money is adjusted to reflect inflationary expectations). The resulting array of answers will yield consistent values for comparing between competing alternative investments.

In general:

$$\text{Market Rate of Return} = \left(1 + \text{Real Rate of Return}\right) \left(1 + \text{Inflationary Expectations}\right)^{-1}$$

Real rates of return generally remain constant over time, with variations occurring as a result of the assumed risk of a financial instrument.

Market values on the other hand will fluctuate over time depending upon the long-term inflationary expectations of the financial community.

SINKING FUND DEPRECIATION*

In computing a levelized fixed charge rate, depreciation may be stated in terms of a sinking fund factor to simplify the calculation. This factor is obtained using book life and discount factor; its use will provide a fund which at the end of the time period will be equal to the original investment. The equation for this factor is:

$$\text{Sinking Fund Depreciation} = \frac{r}{(1 + r)^N - 1}$$

LEVELIZED ANNUAL INCOME TAX

In order to obtain a given return to investors, a company must pay income taxes prior to any income distribution to equity holders. It is important to realize that interest expenses which occur due to the use of bonds are considered operating expenses in terms of income tax provisions, and are paid out of earnings prior to income tax considerations. On the other hand, the return to preferred and common stock holders (dividends) is paid out of after-tax dollars. Because after-tax dollars are used, the effective cost of equity financing is higher than the initial implicit cost of debt financing.

*The total return plus sinking fund depreciation equals the capital recovery factor, where capital recovery factor = $\frac{r (1 + r)^N}{(1 + r)^N - 1}$

N = book life

To determine the revenue requirements associated with paying income taxes, the value can be calculated as follows:

$$\begin{aligned} \text{Levelized annual income tax} &= (\text{capital recovery factor} - \text{straight line depreciation}) \\ &\times \left(1 - \frac{\text{debt ratio} \times \text{debt cost}}{\text{weighted cost of capital}} \right) \\ &\times \left(\frac{\text{tax rate}}{1 - \text{tax rate}} \right) \end{aligned}$$

LEVELIZED ACCELERATED INCOME TAX

Accelerated depreciation is an incentive designed to encourage investment as a stimulus to the overall economy. There are two methods for determining accelerated depreciation that are commonly used: the sum-of-the-years digits method and the double-declining balance changing to the straight line method. The effect of the difference between these methods on the levelized fixed charge rate is negligible considering the accuracy of the calculation. The sum-of-the-years digits method is adopted because of its consistency and relative ease of application. The following formulas may be used to calculate tax preference allowances:

$$\begin{aligned} \text{Levelized annual accelerated depreciation allowance} &= \\ &(\text{accelerated tax depreciation} - \text{straight line depreciation}) \\ &\times \left(1 - \frac{\text{tax rate} (\text{debt ratio}) (\text{debt cost})}{\text{weighted cost of capital}} \right) \\ &\times \left(\frac{\text{tax rate}}{1 - \text{tax rate}} \right) \\ \text{where accelerated tax depreciation} &= \\ &2 \times (\text{capital recovery factor for } N \text{ years}) \\ &\times (n - \text{present worth factor for } n \text{ years}) \\ &\div n (n + 1) (\text{weighted cost of capital}) \end{aligned}$$

$$\text{Straight line depreciation} = \frac{1}{N}$$

N = book life

n = tax life = 2/3 book life

present worth factor = 1/capital recovery factor

OTHER TAXES AND INSURANCE

An allowance of 2 percent of the capital investment is included to cover local property taxes and insurance. Specific values are to be used when detailed estimates are available for client requirements or for a specific site location.

In summary, the annual levelized fixed charge rate (FCR) can be determined as follows:

$$\begin{aligned} \text{FCR} = & \text{return} \\ & + \text{sinking fund depreciation} \\ & + \text{levelized annual income tax} \\ & - \text{accelerated income tax} \\ & + \text{other taxes and insurance} \\ & (\%) \text{ Fixed Charge Rate} \end{aligned}$$

and where

$$\text{Levelized Annual Fixed Costs} = \text{FCR} \times \text{Capitalized Value}$$

REAL RATE OF RETURN

To derive a comparable fixed charge rate in the absence of inflation, the value is found by dividing the nominal fixed charge rate by the levelizing factor based on the general inflation rate and the nominal discount rate. This will insure a consistent treatment of the tax liabilities in an inflating world environment.

Appendix C

LEVELIZING FACTOR

The levelizing calculation is the process of converting a time varying series of payments to an equivalent constant, or time invariant, series. The equivalence is done in a present worth sense.

To determine such a value, the process of levelizing costs that are escalating at a constant annual rate is accomplished by multiplying the cost in the initial year by the appropriate levelizing factor (LF). The levelizing factor is calculated as follows:

$$L = CRF^* \left(\frac{K(1 - K^N)}{1 - K} \right)$$

where

$$K = \frac{1 + e}{1 + r}$$

r = weighted cost of capital

e = the apparent escalation rate of variable costs such that
= $(1 + \text{real escalation}) \times (1 + \text{inflation rate}) - 1$

N = book life

The real escalation rate in this case represents the escalation rate of costs which are expected over and above the general inflation in costs. This allows for different levelizing factors being determined for fuel and O&M expenses where appropriate.

$$*CRF \text{ (Capital recovery factor)} = \frac{r(1 + r)^N}{(1 + r)^N - 1}$$

Appendix D

LEVELIZED CAPACITY FACTOR

We can generally expect a variance in a facility's operating capacity in the early years of the project when it is in its initial stages of operation. To compensate for this variance, we must discount the yearly plant output to present worth, returning it to a yearly value by multiplying by the firm's capital recovery factor. This will put the plant output on a levelized value comparable to the calculated levelized revenue requirements. Dividing the levelized revenue requirements by the levelized plant output will yield the levelized cost of energy.

To accomplish the levelizing of the plants capacity, we multiply the present worth of the capacity levels by the firm's capital recovery as follows:

$$\text{Levelized Capacity Factor} = \sum_{i=0}^N \frac{\text{Plant Output}}{(1+r)^N} \times \text{CRF}_{r,N}$$

r = weighted cost of money

N = book life

APPENDIX E

ECONOMIC ASSUMPTIONS FOR HTGR PROGRAM

Commercial plant basis	Nth Plant	
Capacity factor	70%	
Base date for all costs	January 1980	
Date of operation for all plants	January 1995	
Investment life for all plants	30 Years	
Electricity replacement power costs (Jan. 1980 \$)	40 mills/kW-hr(12.73 \$/10 ⁶ Btu)	
Electricity busbar sale price (Jan. 1980\$)	22 mills/kW-hr(\$7.51 \$/10 ⁶ Btu)	
Fuel cost projections (Jan. 1980 \$) in 1995		
Coal	2.25 \$/MBtu	
Oil	9.25 \$/MBtu	
Natural gas	8.25 \$/MBtu	
Uranium	40 \$/lb U ₃ O ₈	
Conversion	\$6/kg UF ₆	
Separative work (0.2% tails)	\$120/SWU	
Nuclear fuel cycle costs (LEU/Th once through)	\$1.22/MBtu (1/80 \$ levelized over 30 years)	
Coke	\$4.98MBtu (1/95 \$ levelized over 30 years)	
Operation and Maintenance Costs (Jan. 1980 \$)	Fixed (10 ⁶ \$/yr)	Variable- mills/kWt-hr
HTGR-SC (SC/C)	12.0 (12.2)	0.45 (0.95)
Coal Electric (SC/C)	11.0 (11.2)	1.10 (1.60)
HTGR-NHS	12.0	0.60

Common Cost Factors - Utility-owned Facility	Constant Dollars	Inflated Dollars
Weighed cost of capital	4.3%	10.5%
Levelized fixed charge rate	8.3%	15.3%
Allowance for funds during construction	3.5%	8.2%

Common Cost Factors - Private-Industry-Owned-Facility

Weighed cost of capital	7.4%	13.8%
Levelized fixed charge rate	13.0%	22.2%
Allowance for funds during construction	6.9%	12.5%

Real Escalation Rates	Base Inflation		
Construction	6%	1.00%	7.06%
O&M	6%	1.00%	7.06%
Electric power	6%	2.00%	8.12%
Fuel (all) after 1995	6%	3.00%	9.18%

Fossil Fuel	1980 Cost (\$/MBtu)	Average Real Escalation Rate 1980-1995	Base 1995 Cost In 1980 Dollars (%/Yr) (\$/MBtu)	Real Escalation Rate Post-1995 (%/yr)
Coal	1.40	3.2	2.25	3.0
Oil	4.30	5.2	9.25	3.0
Natural gas	2.60	8.0	8.25	3.0

APPENDIX E (Cont'd)

Levelizing Factors (30-Year Levelized)

Utility-owned Facility	1.136	2.108
O&M	1.297	2.408
Electric power	1.490	2.767
Fuel (all)		
Private-Industry-Owned-Facility		
O&M	1.114	1.880
Electric power	1.247	2.105
Fuel (all)	1.403	2.370

APPENDIX P.

Table P-1

SECONDARY HELIUM LOOP
EQUIPMENT VENDOR RESPONSE MATRIX

VENDOR	RESPONSE		RECOMMENDATION	SIMILAR COMMERCIAL EXPERIENCE	COST ESTIMATE
	YES	NO			
<u>PIPING</u>					
1. Metex Corporation	X		Cold Leg & Hot Leg: None	None	None
2. Creusot-Loire	X		Cold Leg & Hot Leg: None	None	None
3. Babcock & Wilcox - Diamond Power	X		Hot Leg: None Cold Leg: External mirror insulation	None Lightwater reactor - main steam lines	None \$300 to \$430 per/ft
4. Energy Products of Idaho	X		Hot Leg: None Cold Leg: Not addressed	Refractory lined vessels for 1500°F and low pressure	None
5. Harbison-Walker ^(a)	X		Hot Leg: Refractory lining & external insulation Cold Leg: External insulation	Piping for petroleum refineries	None
6. AP Green	X		Support of Bigelow-Liptak	--	-
7. Bigelow-Liptak	X		Hot Leg: Internal refractory lined pipe Cold Leg: External fiber insulation	Numerous hydrogen trans- fer lines in ammonia plants for 1500°F and 500 psig	\$4900/ft ASME III \$2500/ft ASME VIII \$2500/ft ASME III \$1305/ft ASME VIII

(a) Vendor response included in this appendix.

SECONDARY HELIUM LOOP
EQUIPMENT VENDOR RESPONSE MATRIX (Cont'd)

VENDOR	RESPONSE		RECOMMENDATION	SIMILAR COMMERCIAL EXPERIENCE	COST ESTIMATE
	YES	NO			
<u>PIPING (Cont'd)</u>					
8. Plibrico West		X			
9. Tapco International		X			
10. Metco Inc.	X		Hot Leg & Cold Leg: None	None, except for sprayed ceramic coatings	None
11. Vallurec	X		Hot Leg & Cold Leg: None	None	None
12. Darchem Energy Ltd.		X			
<u>BELLOWS</u>					
1. Pathway Bellows, Inc.	X		Hot Leg: Gimbal or hinged expansion joints with pressure boundary temperatures limited to 900°F or less Cold Leg: Not addressed	Petroleum & petrochemical applications with temperatures ranging from 1200 to 1800°F	\$66K/unit ASME III
2. AMETEK/Straza	X		Hot Leg: None Cold Leg: Not addressed	Aerospace applications but smaller diameter	None
3. Metal Bellows	X		Hot Leg: Gimbal joint but not sure how to take both temperature and pressure Cold Leg: Not addressed	Nuclear applications	None

SECONDARY HELIUM LOOP
EQUIPMENT VENDOR RESPONSE MATRIX (Cont'd)

VENDOR	RESPONSE		RECOMMENDATION	SIMILAR COMMERCIAL EXPERIENCE	COST ESTIMATE
	YES	NO			
<u>BELLOWS (Cont'd)</u>					
4. Croll-Reynolds ^(a)	X		Hot Leg: Double bellows externally restrained but not sure of material for temperature & pressure Cold Leg: Same expansion joint design with stainless steel	Petroleum applications with pressure of 650 psig and temperature of 1000°F	None
5. EG&G Sealol	X		Hot Leg & Cold Leg: None	None	None
<u>VALVES</u>					
1. G&W Fluid Systems ^(a)	X		Hot Leg & Cold Leg: None, G&W sees a development program for a relatively new product	None, except for valves in non-nuclear applications up to 1400°F	None
2. Borg-Warner Corp.	X		Hot Leg & Cold Leg: None, B-W sees a real problem with the hot leg 40" valve; suggest several smaller valves in parallel	None, except for actuator for 28" steam isolation valve with 5 second closing time	None

(a) Vendor response included in this appendix.

SECONDARY HELIUM LOOP
EQUIPMENT VENDOR RESPONSE MATRIX (Cont'd)

VENDOR	RESPONSE		RECOMMENDATION	SIMILAR COMMERCIAL EXPERIENCE	COST ESTIMATE
	YES	NO			
<u>VALVES (Cont'd)</u>					
3. The Lunkenheimer Co.	X		Hot Leg & Cold Leg: None, suggested Consolidated Controls	None	None
4. Consolidated Controls Corp.	X		Hot Leg & Cold Leg: None	Developed 8" sliding gate valve for coal conversion project for temperatures to 2000°F & pressures up to 1600 psig	None
5. Anchor/Darling Valve Company	X		Hot Leg: Refractory lined 400 lb to be developed Cold Leg: 600 lb valve with pneumatic/hydraulic or electro/hydraulic actuator	None discussed	Hot Leg: None Cold Leg: \$750K to \$800K
6. Sulzer Bros. (a)	X		Hot Leg: None, for time being Cold Leg: Gate valve, system medium operated	Isolation & control valves for 1200°F steam AGR valves for CO2	Hot Leg: \$150K to \$210K for detailed design study Cold Leg: \$350K to \$450K

(a) Vendor response included in this appendix.

SECONDARY HELIUM LOOP
EQUIPMENT VENDOR RESPONSE MATRIX (Cont'd)

VENDOR	RESPONSE		RECOMMENDATION	SIMILAR COMMERCIAL EXPERIENCE	COST ESTIMATE
	YES	NO			
<u>VALVES (Cont'd)</u>					
7. Atwood & Morrill ^(a)	X		Hot Leg: None, this valve is a substantial problem: it will require development and a test loop will be req'd which could take a substantial investment if no facility exists Cold Leg: Not addressed	None	None, development \$500K to \$700K
8. Crane Company	X		Hot Leg & Cold Leg: None	None	None
9. AMETEK: Schutte-Koerting Division	X		Hot Leg & Cold Leg: None	None	None
10. WKM	X		Hot Leg & Cold Leg: None	None	None
11. Wm. Powell Company	X		Hot Leg & Cold Leg: None	None	None
12. Rockwell Int'l - Flow Control Division		X			
13. Pacific Valves		X			
14. Copes-Vulcan		X			
15. Ecolaire-Mosser Industries	X		Hot Leg & Cold Leg: None, R&D program needed	Air cooled and water cooled butterfly valves with refractory lining for gas at 1500°F and 300 psig	None

(a) Vendor response included in this appendix.

SECONDARY HELIUM LOOP
EQUIPMENT VENDOR RESPONSE MATRIX (Cont'd)

VENDOR	RESPONSE		RECOMMENDATION	SIMILAR COMMERCIAL EXPERIENCE	COST ESTIMATE
	YES	NO			
<u>VALVES (Cont'd)</u>					
16. Hopkinsons Limited	X		Hot Leg & Cold Leg: None	Valves for gas cooled reactor stations	None
<u>CIRCULATORS</u>					
1. Mechanical Tech., Inc.	X		None	None	None
2. Dresser Clark		X			
3. Brown-Boveri	X		None	None	None
4. Sulzer Bros. (a)	X		2 stage axial compressor power input 10 MW or 1 stage centrifugal-power input 11 MW	30 blowers for reactor applications with helium, argon, & CO ₂ Max power input: 16 MW Max pressure: 75 bar (1100 psi) Max temperature: 350°C (600°F)	\$3.7 M or \$4.7 M
5. Creusot-Loire		X			
6. Rotoflow (a)	X		One stage centrifugal-power input 15,870 HP	Numerous centrifugal compressors with nitrogen, natural gas, oxygen, helium Max power input: 10,000 HP Max pressure: 600 psi Max temperature: 400°F	

(a) Vendor response included in this appendix.

SECONDARY HELIUM LOOP
EQUIPMENT VENDOR RESPONSE MATRIX (Cont'd)

VENDOR	RESPONSE		RECOMMENDATION	SIMILAR COMMERCIAL EXPERIENCE	COST ESTIMATE
	YES	NO			
<u>CIRCULATORS (Cont'd)</u>					
7. Airesearch Manufacturing Company ^(a)	X		Four centrifugal units in parallel-power input 13,268 HP	Circulator for GA	\$2.4 M development \$200 to \$500/HP for hardware

(a) Vendor response included in this appendix.

Table P-2

STEAM GENERATOR
EQUIPMENT VENDOR RESPONSE MATRIX

VENDOR	RESPONSE		RECOMMENDATION	SIMILAR COMMERCIAL EXPERIENCE	COST ESTIMATE
	YES	NO			
1. Trepaud ^(a)	X		High Pressure: Undulating tube bundle Low Pressure: None	Not addressed	None
2. NEI Power Energy	X		None	Units for Berkeley & Bracley, Oldbury, Wincscale, Hinkley Point B and Hunterston B with CO ₂	None
3. Combustion Engineering, Inc.	X		None	Not addressed	None
4. Rockwell Intl., Energy Systems Group	X		None	None	None
5. Sulzer*(10)	X		High Pressure: Two helical tube bundles Low Pressure: One helical tube bundle	Units for gas cooled reactors - latest delivered for 300 MWe THTR	\$52 M for eight units, \$5.2 M for one unit
6. Foster Wheeler		X			
7. General Atomic Co.	X		High Pressure: Split helical bundle; a new design	HTGR	None
8. Babcock & Wilcox		X			

(a) Vendor response included in this appendix.

HARBISON-WALKER REFRACTORIES

Division of Dresser Industries, Inc.,

2 Gateway Center, Pittsburgh, Pennsylvania 15222

JAMES A. CAPRIO

PRODUCTS MANAGER - PROCESS MAINTENANCE & DEVELOPMENT
INDUSTRIAL MARKET

July 9, 1981

TELEPHONE: 412-562-6606

Mr. Charles R. Snyder
Bechtel Group, Inc.
P. O. Box 3965
San Francisco, California 94119

SUBJECT: Insulated Piping For High
Temperature Helium Service

Dear Mr. Snyder:

Harbison-Walker has had no experience in lining piping systems as described in Mr. Leary's letter. Harbison-Walker does manufacture both refractories and calcium silicate external insulations, both of which will probably have to be incorporated in some way in the pipe lining design. Referring to your "secondary helium loop flow schematic", locations two and three, downstream from the user heat exchanger, can probably be safely lined with an external calcium silicate insulation, as the temperatures are sufficiently low to accommodate this material's maximum service temperature of 1200°F. For this application, we suggest using our Calsilite Insulation, which has excellent insulating properties as well as high strength and good weather ability, typical for calcium silicate type insulations.

For the hot leg piping, in both Case 1 and Case 2, the high temperatures would preclude the use of such insulations without lowering the steel pipe temperature. In addition, lowering the steel pipe wall temperature would probably be beneficial in decreasing the stresses on the pipe. In order to do this, some type of internal insulation composed of refractory would be necessary.

Harbison-Walker has been involved in pipe insulations for petroleum refineries, where the pipe is carrying a erosive catalyst at high temperatures (around 1200°F.) and at significant velocities, notably in FCCU lines. The type of refractory lining I propose is similar to these catalyst lines. The lining will consist of 2" of an erosion resistant refractory, our HARCAST ES brand with wire fiber reinforcement, 5" of H-W LIGHTWEIGHT CASTABLE 20, and 1-1/2" of Calsilite External Insulation. The erosion resistant refractory could give the lining the strength to withstand the high gas velocity. The lightweight material would provide the

Bechtel Group, Inc.
San Francisco, California

- 2 -

July 9, 1981

bulk of the internal insulation properties. I have performed some thermal calculations to represent the heat flow through the pipe lining. These appear on the attachment.

First note that using this proposed lining, it is not possible to get the steel pipe temperature much below 1000°F. Second, the cold face of the pipe is between approximately 170°F. and 200°F., depending on the hot face temperature. If 150°F. or lower is required, more thermal calculations will have to be performed. Finally, please note the difference between the two thermal models. Model BC03 and BC02 incorporate a correction for small (40" OD) diameter thermal properties. Models BECH and BEC5 correspond to a straight wall calculation. The calculations incorporating the small diameter correction probably are closer to representations of what would actually be experienced.

I must add some words of caution. Frankly, we have no feel for the erosion resistance of HARCAST ES in a gas flow of 80,000 cubic feet per minute. Only actual testing could determine the effects. If the grains of the refractory would be eroded by the gas flow, some provision for removal of the grains would have to be incorporated. Another possibility would be to utilize an erosion resistant metal shroud on the interior of the lined pipe. Since these refractories are installed wet, the pipe linings would have to be dried out, prior to assembly of the piping or prior to service. The refractory, of course, will have to be anchored inside the piping, and a standard anchorage method could accomplish this.

To review, we have no actual experience with internal pipe insulation for a high velocity helium system. In terms of a thermal analysis, a two-component castable lining could work. Our concern rests with the ability of the refractory to withstand the high velocities. If you feel this avenue is worth pursuing, please contact me by phone and we could prepare some budgetary material costs for you. The actual installation of the castable refractory and external insulation would have to be performed by a contractor, as well as the dry-out of the refractory.

If you have further interest in this, I may be reached at 412-562-6603. I apologize for the delay in my sending you this information. Thank you for your interest in our products.

Yours very lurly,

Christopher L. Macey
Products Specialist
Process Maintenance & Development

CLM/jmp

Attach.

BECHTEL GROUP

HELIUM LOOP

40" I.D. PIPE, 2" HARCAST ES
5" H-W LIGHTWEIGHT CASTABLE 20
1-1/2" Calsilite Insulation

STRAIGHT WALL CALCULATIONS (ALL IN °F.)

<u>CASE</u>	<u>MODEL</u>	<u>HOT FACE</u>	<u>PIPE WALL TEMPERATURE</u>	<u>COLD FACE</u>	<u>HEAT FLOW</u>
1	BECH	1460°	876°	184°	254
2	BEC5	1650°	998°	197°	295

SMALL Ø CORRECTION (ALL IN °F.)

<u>CASE</u>	<u>MODEL</u>	<u>HOT FACE</u>	<u>PIPE WALL TEMPERATURE</u>	<u>COLD FACE</u>	<u>HEAT FLOW</u>
1	BC03	1460°	844°	172°	218
2	BC03	1650°	948°	186°	258

*IN UNITS OF BTU/SQ.FT./HR.

Estimates performed at .950 emissivity, 80°F. ambient,
no wind, 100% He internal atmosphere.

RECEIVED

APR 3 1981

J. E. LEARY.

TELEPHONE: 203-371-1983
CABLE: CRECO TRUMBLECONN

April 2, 1981

Mr. C. R. Snyder
for J. E. Leary
Project Engineer
Research & Engineering
Bechtel Group, Inc.
Fifty Beale Street
P.O. Box 3965
San Francisco, CA 94119

BECHTEL			
CORANTER PROJECT -- JGB 14806			
DATE	FILE	NO.	NO.
PROJ. ENG.			
PROJ. ENGR.			
MECH. ENGR.			
PROJ. ENGR.			
CIVIL ENGR.			
PLANT DESIGN			
TEST ENGR.			

SUBJECT: Expansion Joints for High Temperature
Helium Service

Dear Mr. Snyder:

Thanks for your letter of March 16, 1981 detailing the conceptual design work you are doing for a high temperature helium recirculating heat transport loop piping system referred to as the secondary helium system.

We have given consideration to the schematic which accompanied your letter and feel that it might be possible for us to offer expansion joints of quite viable design for locations 2 and 3 in either cases 1 or 2. The equipment we have in mind would utilize fairly conventional materials of construction including austenitic stainless steels.

In regard to the expansion joints required for location 1 in either case 1 or 2, the combination of pressure and temperature associated with your design thinking is an entirely different picture. We have supplied expansion joints for installation in piping intended to operate at extremely high levels of temperature, but in all such cases, the operating pressure was really quite low. For example, back in 1953, we supplied a large group of expansion joints constructed almost entirely out of Type 310 stainless steel for installation in a municipal facility in Lansing, Michigan for which the operating temperature was 1700°F.

For combinations of relatively high pressure and temperature, we have supplied expansion joints constructed of stainless steels including, for example, on Bechtel Corporation order No. 1991-14-E-1 for the General Petroleum Corporation in 1953, we supplied a group of

continued . . .

Mr. C. R. Snyder
Page 2
April 2, 1981

expansion joints designed to operate under a pressure of 650 psig at a temperature of 1000°F. These particular expansion joints had FlexoDisc Bellows which were constructed from type 321 stainless steel utilizing rather heavy gauges of metal. The performance of this equipment as well as the large number of expansion joints supplied for the facility in Lansing, Michigan, has been quite satisfactory during the many years in which they have been in service.

Concerning the location 1 possibilities, we are currently evaluating the potential suitability of various materials such as alloy SB-435X and other materials which might possibly offer sufficient strength at elevated temperature as to make practical the design of expansion joints to suit your purposes.

As mentioned in our telephone conversation, where amounts of movement are to be absorbed by expansion joints which must function while conveying fluid under extremely high temperature and pressure, the best approach is normally one which involves joint designs of the double bellows variety so that the major component of movement can be absorbed as parallel lateral movement. If you will examine the enclosed literature items, the type expansion joint construction we have in mind is that we term our FlexoLeed type. Two bellows, acting together and separated by a center pipe portion, each are subjected to angular bending as a single cantilever to correct back into parallelism thus affording the opportunity to absorb relatively great amounts of movement using bellows of practical length.

To be quite frank with you, Mr. Snyder, we are not overly optimistic that there will be a metal or metals available to us that will possess the unique combination of strength and formability factors that may enable us to come up with a viable design for the location 1 applications in which you have interest. On the other hand, if you will be patient with us, we will continue to explore the metallurgical aspects of materials that are either already in existence or soon to be available that may provide a viable answer to your needs.

We thank you for being in contact with us. Should you have any additional specific questions at this time, we will be happy to try to answer them for you. We do thank you for your interest in our company and its products.

Very truly yours,

CROLL-REYNOLDS ENGINEERING COMPANY, INC.

J. J. Quinlan, P.E.
President

JJQ/dmp
Enclosures

25 Graystone St.
Warwick, RI 02886
401-739-3300
Telex: 927778

February 6, 1981

Mr. J. E. Leary
Project Engineer
Research & Engineering
Bechtel Group, Inc.
Fifty Beale Street
P. O. Box 3965
San Francisco, CA 94119

Subject: Isolation Valves for High Temperature Helium Service

Dear Mr. Leary:

We have received your letter addressed to Mr. Soderberg and have reviewed the subject internally. Our Mr. Croy spoke to you on February 6 regarding the connecting pipe selection and some clarification for your valves.

The Fluid Systems Division of the Gulf + Western Manufacturing Company produces a high quality, double trunnion ball valve for nuclear applications, Class 1 and Class 2. For your information, we have supplied valves as large as 28 inches for main steam isolation in nuclear plants. We have also supplied valves in non-nuclear applications up to 1400°F.

We have never produced valves at the temperatures and the pressures you specified, and this would be a development project for us. We know of no other valve manufacturer who does provide such high temperature valves, particularly with any nuclear application. As we see it, you must involve yourself in a development program for a relatively new product.

We would be open to considering such a development project for you and have in-house a complete Engineering staff which does design special valves for special purposes. If you would be interested in pursuing this further, I suggest that you contact us and plan to visit us at our Warwick, Rhode Island facilities to discuss the project further.

Very truly yours,

G+W FLUID SYSTEMS

A handwritten signature in cursive script, reading 'John F. Walter'.

Dr. John F. Walter
General Manager

/pfr

cc: H. Eminger

SULZER

RECEIVED

APR 21 1981

Mailing Address:
1255 Post Street, Suite 911
San Francisco, CA 94109
Telephone: Area Code 415
441-7230

Cable Address: Sulwest
Telex: (WU) 34282

J. E. LEARY

Bechtel Group Inc.
P.O. Box 3965
SAN FRANCISCO, CA 94119

Attn: Mr. J. E. Leary

Please quote our reference
in correspondence and
telephone calls

Your reference

Your letter of

Our reference

Date

SED/sch

April 21, 1981

Re Isolation Valves for High Temperature Service

Gentlemen:

In addition to my letter of Apr. 16, 1981 which discussed gas circulators I am pleased to offer our comments on isolation valves. Sulzer has operating experience with isolation and control valves up to 1200°F medium steam.

Hot leg valves (location 1)

For the time being we do not have a technical solution for a valve to withstand temperatures ranging from 1460 to 1650°F.

Cold leg valves (location 3)

We propose to use valves as described and illustrated in the pamphlet "System Medium Operated Main Steam Isolation Valves for Nuclear Power Stations" which is enclosed for your information. Since the required stroking time is less than 5 sec. and about 30 in. size valves with a large actuating force are involved we suggest to employ system medium operated valves, type DAS630 angle or in-line design (see page 5, fig. 4 of enclosed pamphlet). The costs for one such valve, delivered to U.S. arrival port, duty paid would be between \$ 350,000.- to 450,000.-. A set of four valves is about 10% to 20% less expensive per valve than one valve only. The material is according to nuclear QA standards for pressure parts, i.e. SA 182 F 22.

We do not envisage problems by using Helium instead of steam as operating medium since we have already design proven experience using CO₂ gas (AGR reactors in England).

...

SULZER

San Francisco

Our reference SED/sch

Page 2

Date 4/21/81

To Bechtel Group Inc., San Francisco

I shall be happy to provide you with any additional information which you may require.

Yours sincerely,
SULZER BROS. INC.

Edy O. Sennhauser

Enclosure:

26.75.03; 21.28.00;
Nuclear Technique "Nuclex 72"

SULZER

Mailing Address:
1255 Post Street, Suite 911
San Francisco, CA 94109
Telephone: Area Code 415
441-7230

Cable Address: Sulwest
Telex: (WU) 34282

Bechtel Group Inc.
P.O. Box 3965
SAN FRANCISCO, CA 94119

Attn: Mr. J. E. Leary

Please quote our reference
in correspondence and
telephone calls

Your reference

Your letter of

Our reference

Date

SED/sch

September 15, 1981

Re Isolation Valves for High Temperature Service

Gentlemen:

Upon receipt of our letter of April 21, 1981 your Mr. C. R. Snyder inquired about development costs for the hot leg valves. For a conceptional design study of these valves which comprises identifying technical requirements, reviewing existing documents and literature and preparing a valve concept we estimate that it will take about 4 to 6 manmonths. For a detailed design study consisting of preparing an overall assembly drawing, stress and functional calculations (open/closing behaviour) we estimate the use of an additional 6 to 8 manmonths. The total budget price for above activities would amount to \$ 150,000 to \$ 210,000.-.

I shall be happy to provide you with any additional information which you may require.

Yours sincerely,
SULZER BROS. INC.

Edy O. Sennhauser

RECEIVED

SEP 17 1981

J. E. LEARY

ATWOOD & MORRILL CO., INC.

DESIGNERS AND MANUFACTURERS

PHONE 617 744-5690
TELEX 910299

Special Valve and Control Equipment
POWER PLANT • OIL INDUSTRY • MARINE AND INDUSTRIAL SERVICE

RECEIVED

APR 30 1981

J. E. LEARY.

SALEM, MASSACHUSETTS 01970

April 23, 1981

Bechtel Group, Inc.
P.O. Box 3965
San Francisco, California 94119

Attention: Mr. J. E. Leary - Project Engineer
Research & Engineering

Reference: Bechtel Letter of March 25, 1981 to Atwood & Morrill
c/o R. Burns & Associates

Subject: Isolation Valves for High Temperature Helium Service

Gentlemen:

The referenced letter has been forwarded to me for review and response.

The valve application which is proposed in your letter is indeed demanding. We have reviewed the service conditions and additional data supplied by Mr. Snyder via phone and have the following comments.

Responding specifically to your questions,

1. Atwood & Morrill has provided high technology engineered valves for many demanding applications. Admittedly the service conditions described in your letter are unique and we know of no similar application for which A&M has furnished valves.
2. It is difficult to recommend a specific valve for this application with only what must be considered a cursory review on our part. However, the application would seem to favor some sort of quarter turn valve e.g. ball, butterfly, plug, etc.. Particular problems associated with this application are:
 - a. Fast closure (< 5 seconds)
 - i. For the hot leg valves (which would appear to be approx. 60" size) with linear closure strokes of the order of 60" this would mean 700-800" per minute travel speed and

represents a major problem for power actuators on gate or globe type valves.

- ii. Swing check type valves are not, in our opinion, suitable for such fast closure and consideration must be given, in any case, to the pressure transient resulting from such quick closure.
 - iii. For the cold leg valves the problem is only slightly less severe due to the apparently smaller valve sizes (30").
3. Drawings are not available for any of the aforementioned quarter turn valves.
4. We believe there are several major technology problems which must be solved before an effective valve design can be made. These include
- i. Refractory lining of the valve body
 - ii. Valve seat seal design
 - iii. Shaft seal design
 - iv. Material selection
 - v. Manufacturing methods related to the use of refractory lined valve.

It is, again, difficult to estimate development costs, schedules and individual valve costs based on the information available. However, development costs could be of the order of \$500 to \$700 thousand dollars with a time of 2 to 3 years. Individual valve costs are virtually impossible to predict. However, since material will be a substantial portion of the valve cost, the cost of the Nth set of valves will be highly dependent on when it is ordered as well as start up costs such as patterns, tooling, etc..

I hope the above information is useful. If you desire to discuss the subject further, feel free to call.

Very truly yours,

ATWOOD & MORRILL CO., INC.

S. N. Shields,
Vice President - Engineering

SNS:ndp

cc: Robert Burns & Associates

A. J. McKay, A&M

C. R. Snyder, Bechtel

D. F. Sullivan, A&M

SULZER

Mailing Address:
1255 Post Street, Suite 911
San Francisco, CA 94109
Telephone: Area Code 415
441-7230

Cable Address: Sulwest
Telex: (WU) 34282

RECEIVED
APR 17 1981
J. E. LEARY

Bechtel Group Inc.
P.O. Box 3965
SAN FRANCISCO, CA 94119

Attn: Mr. J. E. Leary

Please quote our reference
in correspondence and
telephone calls

Your reference

Your letter of

Our reference

Date

SED/sch

April 16, 1981

Re Gas Circulators for High Temperature Service

Gentlemen:

In reply to your letter of Mar. 19, 1981 I am pleased to offer our comments as follows:

1) Description of the Application

In the last 20 years we have manufactured about 30 blowers for nuclear reactors. Most of these blowers were at one stage axial or centrifugal machines compressing Helium, Argon, Carbondioxyde or air. The maximum power input was about 16'000 KW, the highest pressure 75 bar and the highest inlet temperature 350 °C.

2) Materials of Construction

The material for the proposed circulators are used in Sulzer standard compressors and gas turbines, i.e. no special materials are required.

3) Recommended Circulators

For each case of the schematic which was attached to your letter we would propose a blower which is hermetically sealed including the driving motor. The construction allows easy accessability to the motor. No rotating seals are required, only tight stuffing boxes for cabling. The unit is one compact casing (see page 17 of the enclosed pamphlet).

Case 1: Axial compressor 3 stages overhung, power input about 10,000 KW.

Case 2: Axial compressor 3 stages overhung, maximum pressure ratio 1.06, power input about 11,000 KW.

...

SULZER

San Francisco

Our reference SED/sch

Page 2

Date 4/16/1981

To Bechtel Group Inc., San Francisco,
Mr. J.E. Leary

Alternatively one centrifugal stage overhung, pressure ratio 1.0758, power input about 15,000 KW.

Note: Power values are very approximate and are to be confirmed.

4) Drawings

To follow later

5) Driver

Preferred type of driver is electric motor

6) Costs

Approximate costs for circulator units will follow later.

More detailed information will follow shortly.

Yours sincerely,
SULZER BROS. INC.

Edy O. Sennhauser

Enclosure:
pamphlet no. 25.01.10

SULZER

BECHTEL OSAWHATGR PROJECT — JOB 14508			
DATE 6-11-81		FILE SOI	
	COPY	ACTION	ROUTE
PROJ. MGR.			✓
PROJ. ENGR.			✓
MECH/INSTR.			✓
PROCESS/CHEM.			
PIPEL STRUCT.			
PLANT DESIGN			
COST ENGR.			
G. Snyder		✓	

Mailing Address
1255 Post Street, Suite 911
San Francisco, CA 94109
Telephone: Area 442-2200
Cable Address: SWWZ
Telex: (WU) 34282

See closing # on p. 2
Let's decide if
proposed study is
worth recommending
for FY '82 -
JEL
RECEIVED
JUN 11 1981
J. E. LEARY

Bechtel Group Inc.
P.O. Box 3965
SAN FRANCISCO, CA 94119

Attn: Mr. J. E. Leary

Please quote our reference
in correspondence and
telephone calls

Your reference

Your letter of

Our reference

Date

SED/sch

June 10, 1981

Re Gas Circulators for High Temperature Service

Gentlemen:

In addition to our letter of April 16, 1981 I am pleased to submit our more specific comments as follows.

1. General

For more than 20 years, Sulzer has developed, designed and supplied gas circulators for different kinds of nuclear reactors. More than 40 centrifugal and axial type circulators for testloops and commercial reactors were delivered. Extended studies were also made for Helim circulators for the Gas Cooled Breeder Reactor and a few patents are registered. The number, type and main technical data of the circulators supplied are indicated in the enclosed reference list.

2. Recommended Circulator for each case

For both bases centrifugal as well as axial type circulators can be offered. The main advantages of the axial circulators are:

- Higher efficiency (approx. 5%)
- Smaller dimensions and lower weights
- Lower installation costs

The main parameters of the circulators are:

- Centrifugal type circulator
one stage overhung impeller

...

San Francisco

To Bechtel Group Inc., San Francisco

Case	1	2
Impeller diameter (mm)	1000	900
Tip speed (m/sec)	270	340
Operating speed (rpm)	5160	7215
Power input (KW)	10600	15050
Compressor frame	R 90-1	

- Axial type circulator
two or three overhung axial stages

Case	1	2
Rotor diameter (mm)	400	400
Number of stages	2	3
Rotor tip speed (m/sec.)	230	230
Operating speed (rpm)	10900	10900
Power input (KW)	9900	14000
Compressor frame	A40-2	A40-3

3. Description of circulator

The centrifugal type gas circulator is described and illustrated on pages 10 and 11 of the enclosed copy "A design and assessment study of gas cooled breeder reactors".

A sectional drawing of the axial type circulator is also enclosed. The main configuration is similar to the centrifugal type circulator.

4. Materials of construction

The materials chosen are Sulzer standard materials for compressors of this pressure and temperature range. The main materials of construction are:

Casing and covers:	cast steel
Inner parts:	steel or nodular cast iron
Shaft:	low alloy steel
Blading:	alloy steel (13% Cr)
Impeller:	low alloy steel

5. Approximate costs

It is rather difficult to indicate costs at this stage of the project. Our best estimate, however, for budgetary purposes is:

One centrifugal circulator:	\$ 4,488,000.-
One axial circulator:	\$ 3,696,000.-

The cost reduction for more than 30 sets would be 10% - 20% per unit.

The cost reduction for four circulators would be approx. 5% per unit.

...

San Francisco

To Bechtel Group Inc., San Francisco

We would be interested in completing more detailed information regarding the circulator such as:

- Comparison axial - centrifugal compressor
- Construction details
- Flow control details
- Information regarding sealing system, lubrication system, bearings, materials of construction, dimensions, erection and maintenance, cooling system, instrumentation, electric motor.

This study is offered at engineering costs (approx. 500 hrs x \$ 60.-/hr.).

I appreciate your replying to above offer.

Yours sincerely,
SULZER BROS. INC.

Edy O. Sennhauser

Enclosure:

Ref.: Gascirculators

"A design and assessment study
of gas cooled breeder reactors"

Drwg. 0-837 751820; paper by
K. Feer and H. Benz "Gas Circulators
in the St. Laurent I Nuclear P.S."
(all in duplicate)

THIS MSG WAS AUTO-INTERCEPTED@1

IS06 0020 21:57GMT
SSFO 0231 22:04GMT 04/14/81
DFLOW LSAROTOFLOW A LSA

4-14-81

BECHTEL INC
SAN FRANCISCO
TLX: 340555

ATTN: MR CHUCK SNYDER

GCZA

REF: HELIUM COMPRESSOR/SDG AND E, LA JOLLA

OUR FILE RC1324

WE THANK YOU FOR YOUR VALUED INQUIRY AND HAVE COMPLETED EXPECTED
PERFORMANCE CALCULATIONS AND PRICING FOR YOUR APPLICATION IN ACCORD-
ANCE WITH CONDITIONS GIVEN IN YOUR TELECON WITH LARRY BLITZ ON
4-10-81.

ROTOFLOW OFFERS A CUSTOM, SINGLE-STAGE, CENTRIFUGAL COMPRESSOR WITH
STAINLESS STEEL CASE AND A TITANIUM IMPELLER, FOR COUPLING TO THE
16,000 HORSEPOWER, 1,800 RPM, 4,000V/3PH/60 HZ, DRIP-PROOF ELECTRIC
MOTOR DRIVER (FURNISHED FOR INSTALLATION ON PURCHASER'S FOUNDATION)
THROUGH THE 1:4 SPEED INCREASING GEARBOX. THE COMPRESSOR AND GEAR ARE
MOUNTED ON AN 18' X 8' FABRICATED STEEL BASEPLATE WITH THE WATER-
COOLED, DUAL-PUMP LUBE SET AND NEMA-4 ELECTRICAL SYSTEM AND CONTROL
PANEL.

COUPLINGS AND COUPLING GUARDS ARE PROVIDED. MOTOR STARTERS ARE
PURCHASER-SUPPLIED, AS ARE PERSONNEL BURN GUARDS, IF REQUIRED.

EXPECTED PERFORMANCE FOR THE MACHINE OFFERED IS AS FOLLOWS (YOUR SPECIFIED NUMBERS IN PARENTHESES):

DESIGN

----- COMPRESSOR

MOLECULAR WEIGHT (HE)	(4)
P1 PSIG	(700)
T1 DEG F	(625)
P2 PSIG	(735)
T2 DEG F	653
FLOW/ACFM	(80,000)
RPM	7,200
SHAFT HORSEPOWER	15,870
EFFICIENCY PERCENT	77
TIP SPEED/FPS	1,160
FLANGES IN/OUT (INCHES)	60/60 ?

$$\frac{\$277K}{16K} = \$17.3 / HP$$

ESTIMATED PRICE, F.O.B. LOS ANGELES, CA, FOR THE COMPLETE, TESTED SYSTEM, AS DESCRIBED, IS: USD 950,000.00.

IF THE COMPRESSOR DRIVE MOTOR IS DELETED FROM ROTOFLOW'S SCOPE OF SUPPLY, DEDUCT USD 276,655.00 FROM THE SYSTEM PRICE QUOTED ABOVE.

PRESENT SCHEDULING IS: PRELIMINARY DRAWINGS MAILED SIX WEEKS AFTER ORDER DATE, EQUIPMENT SHIPPED EIGHT TO TEN MONTHS AFTER FINAL DRAWING APPROVAL, DEPENDENT ON GEAR AND MOTOR LEAD-TIMES. IMPROVED DELIVERY IS POSSIBLE, AS REQUIRED, WITH SPECIAL EXPEDITING OF LONG LEAD ITEMS.

SHAFT SEALING FOR THIS APPLICATION WILL REQUIRE SPECIAL ATTENTION, IF OUR OFFER IS OF INTEREST.

?

ROTOFLOW CORP/D L WARNOCK

CC: JH, LEB

ENDNNNN

ROTOFLOW LSA

APPENDIX P - ATTACHMENT 8

A RESEARCH MANUFACTURING COMPANY

A DIVISION OF THE GARRETT CORPORATION
 1000 W. W. GARRETT • PHOENIX, ARIZONA 85001
 TELEPHONE (602) 944-3000 • CABLE: GARRETT • PHOENIX

In reply refer to:
 SJAT-1129-0609

June 9, 1981

BECHTEL GROUP, INC.
 P. O. Box 3965
 San Francisco, California 94119

Attention: Mr. C. R. Snyder

Subject: Helium Circulator

Gentlemen:

This letter is to confirm the telephone conversation of May 8, 1981, with Mr. Kurt Wieland, during which the technical approach for the design and development of a helium circulator for your requirements as stipulated in your letter to Mr. Al Stimac, Garrett Turbine Engine Company, Phoenix, Arizona, was discussed.

A preliminary determination of the dimensions of the circulator and the power requirements was made for four units operating in parallel at Case 1 and Case 2 conditions.

The results are as follows:

	Case 1	Case 2
Weight Flow Rate lb/hr	1.02×10^6	$.92 \times 10^6$
lb/sec	70.83	63.88
Inlet Pressure, PSIA	667	697
Outlet Pressure, PSIA	702	750
Inlet Temperature, °F	623	736
Outlet Temperature, °F	649	278
Impeller Input Power, HP	3,317	4,755
Impeller Rotational Speed, RPM	11,500	14,500

The impeller diameter would be approximately 22 inches and the housing diameter approximately 60 inches.

RECEIVED

JUN 11 1981

J. E. LEARY

We do not have a circulator unit developed for these requirements. However, we have components in our stable of turbomachines that have the desired performance or can be adapted with not too significant changes.

The circulator would be configured similar to the circulator unit built by AiResearch for General Atomic which was operating at 1000 psig, except that the impeller diameter would be increased approximately 2.5 times; this allows the use of an available gas turbine compressor impeller. Also a different cooling concept would be used for compatibility with the higher inlet temperature. AiResearch has built compressor units for temperatures of 1000°F inlet and 1500°F outlet. Similar construction methods, selection of materials and cooling methods can be employed.

The shaft seal would be a pressure balanced carbon face seal. A differential pressure controller would maintain a differential pressure of 5 psi nominal between the helium and lube oil used as balance fluid.

The rotating assembly would be supported on hydrodynamic bearings incorporating anti-whirl features.

Hydrodynamic double acting thrust bearings will absorb the impeller thrust.

A commercial gear speed increaser transmits the power from an AC induction motor (e.g., 2300 volts 3-phase) to the impeller via gear type flexible couplings. The high speed coupling would be our own design with vibration dampers - it would be incorporated into the compressor module.

The hydraulic system includes not only the differential pressure control but also high pressure and low pressure lube pumps; a recirculation pump for oil cooling, the oil to water heat exchanger, oil filters (replaceable during operation) and pressure controllers.

The circulator unit would be designed as complete system for turn-key installation at the customer plant. The testing would be done on air to measure the air equivalent performance on an available dynamometer. Static testing would be done with helium to test for leak tightness. Unless funded, no full power tests would be performed at the manufacturer's facility due to lack of required electrical power. However, full speed tests would be done on air with a smaller motor.

The design and development cost would be roughly between \$2 and \$4 Million, exclusive of the first set of hardware. The hardware cost for a developed product statistically ranges between \$200 and \$500 per hp with the higher figure probably being more representative for a small quantity release, considering also the special design features.

SJAT-1129-0609
June 9, 1981

As discussed, it appears to be desirable to provide some protection of the impeller from particles that may separate from the refractory lining of the ducting. You have asked for quantitative information about the erosive effects of entrained solids. It just so happened that an article published in the last Transaction of The ASME, Journal of Engineering for Power, discusses this subject. We have enclosed a copy for your information.

Our experience indicates that the injection of just a few pounds of crushed quartz can cause complete loss of the blade tips; therefore, some settling chamber ahead of the compressor inlet or inertia type filters, as used on helicopter engines, may be considered if further studies indicate that migration of refractory lining material may be a distinct possibility.

We trust that this information will be of help. If you have further questions, please do not hesitate to contact this office.

Very truly yours,

AIRESEARCH MANUFACTURING COMPANY
A Division of The Garrett Corporation

John A. Turnquist
Environmental & Energy Systems Sales

JAT:lhs
Enclosure

ECHANGEURS

TREPAUD

44 R. LA BOETIE 75008 PARIS

TÉLÉPHONE : 562.64.10
563.92.99 - 563.87.68 - 563.62.17

TÉLEX : 290446 F

TELEGR. : REFROITREPO-PARIS

ATELIERS : STE DE CONSTRUCTION
DES APPAREILS TREPAUD
155 QUAI AULAGNIER 92600 ASNIERES
S.A. AU CAPITAL DE 1.638.000 F

V/Réf. JEL/lr du 9 avril 1981

N/Réf. GT/DA - 155 375

Dos. 7730

PARIS, LE 30 OCT. 1981

BECHTEL GROUP INC.,

Fifty Beale Street

P.O. Box 3965

SAN FRANCISCO CA 94119

U. S. A.

à l'attention de Monsieur J.E. LEARY
Project Engineer
Research Engineering

Messieurs,

Suite à votre appel d'offre cité en référence, nous avons l'honneur de vous remettre sous ce pli nos meilleures conditions de prix et délai pour la fourniture de :

- 8 Générateurs de vapeur de 240 MWth
- 1 Générateur de vapeur de 118 MWth

Votre commande serait réalisée par les Ateliers Mécanique et Chaudronnerie de CREUSOT LOIRE, en application de nos procédés brevetés.

Vous souhaitant bonne réception de ce courrier et en espérant avoir le plaisir de vous recevoir à PARIS, nous restons à votre disposition pour vous fournir tout renseignement complémentaire.

Veuillez agréer, Messieurs, l'expression de nos sentiments distingués.

P. J. - Spécification n° 811138.00.602

" n° 811138.00.601

Conditions commerciales.

ECHANGEURS TREPAUD S.A.
Le Président Directeur Général

P. S. - Il ne vous sera pas demandé de rémunération supplémentaire pour l'application de nos brevets à cette affaire.

ECHANGEURS TRÉPAUD
(letterhead)

BECHTEL GROUP INC.
Fifty Beale Street
P.O. Box 3965
SAN FRANCISCO CA 94119
U.S.A.

DELIVERED NOV 11 1981

Attn: Mr. J.E. LEARY
Project Engineer
Research Engineering

Your Ref.: JEL/lr of 9 April 1981
Our Ref.: GT/DA - 155 375
Dos. 7730

Paris, Oct. 30, 1981

Dear Sirs:

In response to your referenced request for a quotation, it is our pleasure to send you herewith our best terms for price and delivery of:

- Eight 240 MWth steam generators
- One 118 MWth steam generator

Your order will be filled by the Mechanical and Metalwork Shops of CREUSOT LOIRE, applying our patented procedures.

In the expectation that this letter will be well received and awaiting the pleasure of receiving you in PARIS, we are at your disposal to furnish any supplementary information.

Please accept our kindest regards,

ECHANGEURS TRÉPAUD S.A.
President-General Director
(signed)

Encl.: Specification No. 811138.00.602

" No. 811138.00.601

Commercial conditions

P.S. You will not be requested to pay any additional compensation for the use of our patents in this regard.

ÉCHANGEURS

TREPAUD

44 R. LA BOETIE 75008 PARIS

TELEPHONE : 562.64.10

563.92.99 - 563.87.68 - 563.62.17

TELEX : 290446 F

TELEGR. : REFROITREPO-PARIS

ATELIERS : STE DE CONSTRUCTION

DES APPAREILS TREPAUD

155 QUAI AULAGNIER 92600 ASNIERES

S.A. AU CAPITAL DE 1.638.000 F

N/Réf. dos. 7730 - 155 375

PARIS, LE 30 OCT. 1981

COMMERCIAL QUOTATION

SPECIFICATION N°
SPECIFICATION

INDICE
- REVISION :

DISTRIBUTION
DISTRIBUTION

Par
By

ECHANGEURS TREPAUD

1 + 8 STEAM GENERATORS
FOR HIGH TEMPERATURE

TREPAUD PATENTS

COMMERCIAL QUOTATION

[illegible]

COMMERCIAL QUOTATION

1. SUPPLY - WEIGHTS

1.1 8 steam generators according to technical specification N°81 1138 00601 rev 1
and drawing N°10 001

Approx. unit weight = 142 tons

1.2 1 steam generator according to technical specification n°81 1138 00 602 rev 0
and drawing n° 20 001

Approx. unit weight = 71 tons

2. UNIT PRICES

2.1 For each of the 8 steam generators of item 1.1

.....10 906 000 french francs

2.1 For the steam generator of item 1.2

.....6 620 000 french francs

Above prices are to be understood :

- . free of any french or foreign taxes
- . for vessels packed in a sea worthy packing, leigth weight type, and with a load distributor under the saddles.
- . openings packed, setting under nytrogen pressure when leaving our works but without pressure keeping device.
- . for material delivered from FOR to FOB LE HAVRE, without intermediate storage, french clearance included.
- . subject to escalation according to the escalation formula given in § 3

3. ESCALATION FORMULA

$$P = P_0 \left(0,10 + 0,55 \frac{Aicc}{Aicc_0} + 0,35 \frac{S}{S_0} \right)$$

initial indexes : $Aicc_0 = 263$ (index of july 1981)

$S_0 = 355,1$ (index of august 1981)

final indexes : $Aicc$ = indexes for material in stainless steel 304 H, to published for the month of acceptance of materials in our works

S = average of the wages indexes to be published for the months of achievement of the vessels.

4. DELIVERY

From the date of formal order : delivery spread out between the 15th and 20th months after order and for material delivered FOB Le HAVRE.

5. PAYMENT CONDITIONS

By cheque in french francs, 30 days after date of invoice.

- . 20 % with order
- . 20 % upon delivery of fabrication documents (main lay out drawings, design datas)
- . 30% upon receipt of materials in our Chalon/saône works
- . balance on FOB LE HAVRE delivery.

6. OPTION

All our hereabove conditions are valid for a total order of the 9 vessels received before the 31 december 1981.

ÉCHANGEURS

TREPAUD

44 R. LA BOETIE 75008 PARIS

TELEPHONE : 562.64.10

563.92.99 - 563.87.68 - 563.62.17

TELEX : 290446 F

TELEGR. : REFROITREPO-PARIS

ATELIERS : STE DE CONSTRUCTION

DES APPAREILS TREPAUD

155 QUAI AULAGNIER 92600 ASNIERES

S.A. AU CAPITAL DE 1.638.000 F

N/Réf. dos. 7730 - 155 375

PARIS, LE 30 OCT. 1981

SPECIFICATION N° 811138.00.601

Rev. 1

8 STEAM GENERATORS FOR HIGH TEMPERATURE

TREPAUD Patents

240 Mwth

DIVISION CHAUDRONNERIE — PRESSURE VESSEL DIVISION
USINE DE CHALON sur SAONE — PLANT of CHALON sur SAONE

Télex : 800131 - Tél. (85) 46.80.34 - 1, Avenue de Verdun. B.P. 78 - 71103 Chalon sur Saône Cédex

SPECIFICATION N° 8.11138.00.601 INDICE : 0
SPECIFICATION REVISION :

DISTRIBUTION
DISTRIBUTION

Par
By

à
to

ECHANGEURS TREPAUD

8 STEAM GENERATORS FOR HIGH TEMPERATURE

TREPAUD Patents

240 Mwth

0	29.10.81	R. BOVAGNE	29.10.81						
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SIEGE SOCIAL : 42. RUE D'ANJOU — 75008 PARIS

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SUMMARY

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1. SUBJECT
2. GENERAL DESCRIPTION OF THE PROCESS
3. WORKING CONDITIONS
4. STEAM GENERATOR DESCRIPTION
5. CONSTRUCTION CODE
6. DESIGN CONDITIONS
7. FABRICATION ARRANGEMENTS
 - 7.1. Cylindrical shell
 - 7.2. Closing taper
 - 7.3. Top channel - Bottom channel
 - 7.4. Inner shell
 - 7.5. Bundle of tubes
 - 7.6. Baffles
 - 7.7. Skirt
 - 7.8. Thermal barrier
8. MATERIALS
 - 8.1. Plates SA 240 Grade 304 H

8.2. Forgings SA 182 Grade F 304 H

8.3. Bolting SA 193 B7 - SA 194 2 H

8.4. Tubes : 800 H alloy

8.5. Plates SA 515 Grade 70

9. FABRICATION

9.1. Lay out - cutting

9.2. Forming

9.3. Welding

9.4. Assembling procedure

9.5. Heat treatment

10. INSPECTION

11. TESTS

12. PICKLING AND PASSIVATION

13. SHIPPING

1. SUBJECT

This specification concerns the construction of 8 steam generators, heated with helium (240 Mwth).

2. GENERAL DESCRIPTION OF THE PROCESS

It consists of producing overheated steam from a heating gas, which is helium.

Heating process and the main constituents are in agreement with TREPAUD Patents.

Water and steam flows around inside tubes, helium flows around outside the tubes.

3. WORKING CONDITIONS

	T°C		P MPa		Output kg/h
	inlet	outlet	inlet	outlet	
water steam	232	565	16,55	16,45	349 266
helium	793	328	4,8	4,6	394 625

4. STEAM GENERATOR DESCRIPTION

The steam generator is set vertically on a skirt.

Its main characteristics are :

- ϕ i 2 300
- distance between tubesheets : 14 000
- 13 baffles
- 2 652 undulates tubes ϕ 16 x 12

- inner shell ϕ 1 330
- helium inlet and outlet ϕ 900
- 2 water inlets ϕ 300
- 2 steam outlets ϕ 350
- overall height 18 200

5. CONSTRUCTION CODE

ASME Code - Section VIII - Division 2 - 1980 edition - Winter
1980 Addenda and Code Case 1 592 included.

6. DESIGN CONDITIONS

	Temperature °C	Pressure (MPa)	
		steam water	helium
Top channel	565	16,55	4,8
Cylindrical shell	top		4,8
	bottom		4,8
Bottom channel	232	16,55	4,8
Tubes	top	16,55	4,8
	bottom	16,55	4,8

Temperatures of the components of top channel and top part of the cylindrical shell are calculated considering use of a thermal barrier.

7. FABRICATION ARRANGEMENTS

7.1. Cylindrical shell

It is composed of :

- bottom part : 3 shells ϕ i 2 300
thick. 58, 62, 67
- top part : 2 shells ϕ i 2 300
thick. 72

7.2. Closing taper :

The closing taper ensures junction between bottom shell and bottom channel. Its thickness is 58 mm. It is supported by the skirt.

7.3. Top channel - Bottom channel :

Both are composed with the same elements

Thickness
(mm)

	Top channel	Bottom channel
Middle part ϕ i 900	150	80
Tubesheet	240	185
Spherical crown	111	90

Top channel is equipped with 2 steam outlets ϕ 350 and 2 manholes.

Bottom channel is equipped with 2 water inlet nozzles ϕ 300 and 2 manholes.

7.4. Inner shell :

An inner shell - ϕ e 1 330, thick. 15- fills the middle part of the steam generator. It provides an annular area for the tubes.

Each end of the shell is sealed by an elliptical head. Top and bottom parts of the shell are centered in the bore of top and bottom channels.

7.5. Bundle of tubes :

It is composed of 2 652 undulated tubes, TREPAUD patents, equally distributed in 6 sectors.

The tubes - ϕ e 16, thick. 2- are welded together on to the tubesheet through Internal Bore Welding process.

7.6. Baffles :

The 13 baffles ensure supporting and guiding of the tubes. They are composed of toothed-rack shaped bended plates -50 x 1-, welded together.

7.7. Skirt :

The skirt ensures to support the vessel, keep it steady and fixed on the foundations. It is 30 mm thick. The bottom part is a crown equipped with anchors.

7.8. Thermal barrier :

Thermal barrier is used to protect the channel and top shells from high temperature helium, so as to reduce component elements temperature.

It is composed of a stainless steel shell, 10 mm thick.

On helium side, it concerns the middle part, the tubesheet and the cylindrical shell. It involves also increase of helium flowing rate.

8. MATERIALS

They are in agreement with ASME Code Section II.

8.1. Plates SA 240 Grade 304 H :

Cylindrical shell, closing taper, spherical crowns, inner shell, baffles, thermal barrier.

8.2. Forgings 182 Grade F 304 H :

Middle parts, tubesheets.

8.3. Bolting SA 193 B 7 - SA 194 2 H :

Manholes equipment.

8.4. Tubes 800 H alloy

8.5. Plates SA 515 Grade 70

Skirt.

9. FABRICATION

9.1. Lay out - cutting :

Stainless steels are laid out through conventional means. They are cut by plasma torch or sheared or machined.

9.2. Forming :

Cold bending of the cylindrical shell, of the inner shell, of the closing taper.

Hot forming of spherical crowns.

9.3. Welding :

Manual coated electrode welding.

Automatic submerged arc welding or TIG.

Welding of tubes on the tubesheet is performed through automatic TIG process Internal Bore Welding.

9.4. Assembling Procedure :

Assembling of the generator is performed through different steps :

- a. Positionning and fitting of the 2 channels, spherical crowns not assembled.
- b. Assembling of the inner shell.
- c. Fitting and welding of the tubes bundle and baffles.
- d. Assembling and welding of the thermal barrier, the cylindrical shell and the closing taper.
- e. Hydraulic and tightness tests outside the tubes.
- f. Assembling, welding of the spherical crowns of the channels.
- g. Assembling, fitting and welding of the skirt.
- h. Hydraulic and tightness tests inside the tubes.

9.5. Heat treatment :

No heat treatment.

10. INSPECTION

Inspection shall be performed by a qualified external Office chosen by common consent of the Client and the Fabricant.

It shall mainly consist in :

- mill tests of materials with provided records ;
- checking of fabrication drawings and mechanical calculation sheets ;

- qualification of welding procedures ;
- attending main inspection operations ;
- examination of fabrication test plates ;
- attending the hydraulic and tightness tests.

A fabrication file shall be set up for each vessel.

11. TESTS

Hydraulic test of the cylindrical shell : at a minimum pressure of 6,24 MPa for a design pressure of 4,8 MPa.

Hydraulic test of the bundle : at a minimum pressure of 21,52 MPa for a design pressure of 16,55 MPa.

A tightness test shall be performed on the whole tubes bundle, first from outside, then from inside.

12. PICKLING AND PASSIVATION

Pickling and passivation of the vessels shall be performed.

13. SHIPPING

The steam generators shall be entirely completed in the shops.

Package shall be made to meet sea transport conditions with tight closing of nozzles, under dry nitrogen.

They shall be equipped with 2 supports for sea transport.

They shall be protected by a polypropylene tightening covering.

8 Steam Generators 240 MW. th.

ÉCHANGEURS

TREPAUD

44 R. LA BOETIE 75008 PARIS

TELEPHONE : 562.64.10
563.92.99 - 563.87.68 - 563.62.17

TELEX : 290446 F

TELEGR. : REFROITREPO-PARIS

ATELIERS : STE DE CONSTRUCTION
DES APPAREILS TREPAUD

155 QUAI AULAGNIER 92600 ASNIERES
S.A. AU CAPITAL DE 1.638.000 F

N/Réf. dos. 7730 - 155 375

PARIS, LE 30 OCT. 1981

SPECIFICATION N° 811138.00.602

Rev. 0

1 STEAM GENERATOR FOR HIGH TEMPERATURE

TREPAUD Patents

118 Mwth

CREUSOT-LOIRE

DIVISION CHAUDRONNERIE — PRESSURE VESSEL DIVISION

USINE DE CHALON sur SAONE — PLANT of CHALON sur SAONE

Télex : 800131 - Tél. (85) 46.80.34 - 1, Avenue de Verdun. B.P. 78 - 71103 Chalon sur Saône Cédex

SPECIFICATION N° 811138 00 602 INDICE 0
SPECIFICATION REVISION :

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Par
By

à
to

ECHANGEURS TREPAUD

1 STEAM GENERATOR FOR HIGH TEMPERATURE

TREPAUD Patents

118 Mwch

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On communiqué à des tiers. Toutes précautions utiles devront être prises pour en éviter la divulgation.

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 - 7.5. Bundle of tubes
 - 7.6. Baffles
 - 7.7. Skirt
 - 7.8. Thermal barrier
8. MATERIALS
 - 8.1. Plates SA 240 Grade 304 H

8.2. Forgings SA 182 Grade F 304 H

8.3. Bolting SA 193 B7 - SA 194 2 H

8.4. Tubes : 800 H alloy

8.5. Plates SA 515 Grade 70

9. FABRICATION

9.1. Lay out - cutting

9.2. Forming

9.3. Welding

9.4. Assembling procedure

9.5. Heat treatment

10. INSPECTION

11. TESTS

12. PICKLING AND PASSIVATION

13. SHIPPING

1. SUBJECT

This specification concerns the construction of 1 steam generator ,
heated with helium (118 Mwth).

2. GENERAL DESCRIPTION OF THE PROCESS

It consists of producing overheated steam from a heating gas, which
is helium.

Heating process and the main constituents are in agreement with
TREPAUD Patents.

Water and steam flows around inside tubes, helium flows around outside
the tubes.

3. WORKING CONDITIONS

	T °C		P MPa		Output kg/h
	inlet	outlet	inlet	outlet	
water steam	257	343	4,38	4,28	218 883
helium	690	343	4,38	4,18	235 868

4. STEAM GENERATOR DESCRIPTION

The steam generator is set vertically on a skirt.

Its main characteristics are :

- ϕi 1 700
- distance between tubesheets : 16 000
- 15 baffles
- 1 782 undulated tubes ϕ 16 x 13

- inner shell ϕ 1 040
- helium inlet : ϕ 900
- helium outlet : ϕ 800
- 1 water inlet ϕ 250
- 2 steam outlets ϕ 350
- overall height 19 250

5. CONSTRUCTION CODE

ASME Code, Section VIII, division 2, 1980 edition, Winter 1980
Addenda and Code Case 1 592 included.

6. DESIGN CONDITIONS

	Temperature °C	Pression (MPa)	
		steam water	helium
Top channel	565	4,38	4,38
Cylindrical shell	top		4,38
	bottom		4,38
Bottom channel	290	4,38	4,38
Tubes	top	4,38	4,38
	bottom	4,38	4,38

Temperatures of the components of top channel and top part of the cylindrical shell are calculated considering use of a thermal barrier.

7. FABRICATION ARRANGEMENTS

7.1. Cylindrical shell :

It is composed of :

- bottom part : 2 shells ϕ i 1 700
thick.38

- top part : 3 shells ϕ i 1 700
thick.40

7.2. Closing taper :

The closing taper ensures junction between bottom shell and bottom channel. Its thickness is 58 mm. It is supported by the skirt.

7.3. Top channel - Bottom channel :

Both are composed with the same elements

Thickness
(mm)

	Top channel	Bottom channel
Middle part ϕ i 900	30	20
Tubesheet	75	60
Spherical crown	20	20

Top channel is equipped with 2 steam outlets ϕ 350 and 2 manholes.

Bottom channel is equipped with 1 water inlet nozzle ϕ 250 and 2 manholes.

7.4. Inner shell :

An inner shell - ϕ e 1 040, thick. 20- fills the middle part of the steam generator. It provides an annular area for the tubes.

Each end of the shell is sealed by an elliptical head. Top and bottom parts of the shell are centered in the bore of top and bottom channels.

7.5. Bundle of tubes :

It is composed of 1 782 undulated tubes, TREPAUD patents, equally distributed in 6 sectors.

The tubes - ϕ 16, thick. 1.5- are welded together on to the tubesheet through Internal Bore Welding process.

7.6. Baffles :

The 15 baffles ensure supporting and guiding of the tubes. They are composed of toothed-rack shaped bended plates -50 x 1-, welded together.

7.7. Skirt :

The skirt ensures to support the vessel, keep it steady and fixed on the foundations. It is 30 mm thick. The bottom part is a crown equipped with anchors.

7.8. Thermal barrier :

Thermal barrier is used to protect the channel and top shells from high temperature helium, so as to reduce component elements temperature.

It is composed of a stainless steel shell, 10 mm thick.

On helium side, it concerns the middle part, the tubesheet and the cylindrical shell. It involves also increase of helium flowing rate.

8. MATERIALS

They are in agreement with ASME Code Section II.

8.1. Plates SA 240 Grade 304 H :

Cylindrical shell, closing taper, spherical crowns, inner shell, baffles, thermal barrier.

8.2. Forgings 182 Grade F 304 H :

Middle parts, tubesheets.

8.3. Bolting SA 193 B 7 - SA 194 2 H :

Manholes equipment.

8.4. Tubes 800 H alloy

8.5. Plates SA 515 Grade 70

Skirt.

9. FABRICATION

9.1. Lay out - cutting :

Stainless steels are laid out through conventional means. They are cut by plasma torch or sheared or machined.

9.2. Forming :

Cold bending of the cylindrical shell, of the inner shell, of the closing taper.

Hot forming of spherical crowns.

9.3. Welding :

Manual coated electrode welding.

Automatic submerged arc welding or TIG.

Welding of tubes on the tubesheet is performed through automatic TIG process Internal Bore Welding.

9.4. Assembling Procedure :

Assembling of the generator is performed through different steps :

- a. Positionning and fitting of the 2 channels, spherical crowns not assembled.
- b. Assembling of the inner shell.
- c. Fitting and welding of the tubes bundle and baffles.
- d. Assembling and welding of the thermal barrier, the cylindrical shell and the closing taper.
- e. Hydraulic and tightness tests outside the tubes.
- f. Assembling, welding of the spherical crowns of the channels.
- g. Assembling, fitting and welding of the skirt.
- h. Hydraulic and tightness tests inside the tubes.

9.5. Heat treatment :

No heat treatment.

10. INSPECTION

Inspection shall be performed by a qualified external Office chosen by common consent of the Client and the Fabricant.

It shall mainly consist in :

- mill tests of materials with provided records ;
- checking of fabrication drawings and mechanical calculation sheets ;

- qualification of welding procedures ;
- attending main inspection operations ;
- examination of fabrication test plates ;
- attending the hydraulic and tightness tests.

A fabrication file shall be set up for each vessel.

11. TESTS

Hydraulic test of the cylindrical shell : at a minimum pressure of 6,57 MPa for a design pressure of 4,38

Hydraulic test of the bundle : at a minimum pressure of 6,57 MPa for a design pressure of 4,38 MPa.

A tightness test shall be performed on the whole tubes bundle, first from outside, then from inside.

12. PICKLING AND PASSIVATION

Pickling and passivation of the vessel shall be performed.

13. SHIPPING

The steam generator shall be entirely completed in the shops.

Package shall be made to meet sea transport conditions with tight closing of nozzles, under dry nitrogen.

It shall be equipped with 2 supports for sea transport.

It shall be protected by a polypropylene tightening covering.

Weight of Vessel. 71 T

SULZER

Mailing Address:
1255 Post Street, Suite 911
San Francisco, CA 94109
Telephone: Area Code 415
441-7230

Cable Address: Sulwest
Telex: (WU) 34282

Bechtel Group Inc.
P.O. Box 3965
SAN FRANCISCO, CA 94119

Attn: Mr. J. E. Leary

RECEIVED
JUN 12 1981
J. E. LEARY

Please quote our reference
in correspondence and
telephone calls

Your reference

Your letter of

Our reference

Date

SED/sch

June 11, 1981

Re Steam Generators for HTGR Indirect Cycle Plant

Gentlemen:

In reply to your letter of April 9, 1981 please note that Sulzer has developed and manufactured steam generators for gas-cooled reactors for about 20 years. A descriptive documentation of some of these is enclosed. The latest steam generator delivered was the one for the German HTGR Prototype (THTR-300 MWe). Presently we are evaluating steam generators for a German 2250 MWth HTGR co-generation plant.

We have reviewed your scheme. In the following we present our comments on the two types of steam generators as inquired.

1. HP-Steam Generator (1 of 8 units)

We have based our calculations on the water/steam side power (240 MWth) and - in order to satisfy the heat balance - had to adjust the helium side. We have selected to leave the temperatures unchanged and reduce the helium flow from 109.7 kg/s (870000 lbs/h) to 99.3 kg/s.

Thermal layout:

The thermal data per steam generator unit are as follows:

Thermal power transferred	240 MW
Helium: inlet temperature	793°C
inlet pressure	49 bar
outlet temperature	328°C
pressure drop	0.85 bar
massflow	99.3 kg/s

...

San Francisco

To Bechtel Group Inc., San Francisco

Water/steam:	FW temperature	232°C
	FW pressure	186 bar
	steam temperature	566°C
	steam pressure	165 bar
	massflow	97 kg/s

The helium pressure drop of 0.85 bar is dissipated in the heat transfer section. For parasitic losses another 0.2 to 0.3 bar should be added. Thus not more than approx. 50% of the allowable pressure drop (30 psi) can be used with a reasonable steam generator design. Note that this reduction in pressure drop reduces considerably the circulator pumping power.

The water/steam side pressure drop of 21 bar includes orificing for flow stability.

Design:

After reviewing several conceptual options we have selected the once-through helix steam generator consisting of two bundles of helically coiled tubes. In the upper (hot end) bundle the tubes are spaced more widely than in the lower bundle. This is to reduce the adverse effect of the extremely high helium temperature gradient through the relatively thick tube wall. The high temperature together with a large gradient poses severe material and stress problems.

The tube bundles are surrounded by a gas-guiding shroud which is externally insulated. The whole unit is enclosed in a pressure shell which would normally be insulated on the outside. Inspection and safety considerations may suggest inside insulations.

The hot helium enters at top centre, flows over the heat exchange surface, and after leaving the lower bundle is passed through the annulus to the exit sideways on the top. With external insulation the pressure shell is thus kept at cold helium temperature. Feed-water enters sideways at the bottom, flows upwards through the tubes. Steam leaving the upper bundle is passed through straight tubes in the centre of the bundle down to the bottom exit.

The dimensions are shown on the enclosed drawing no. 2-103.074.400.

Materials:

The upper bundle and the upper section of the lower bundle are made from Incoloy 800 tubing. The lower section is 2½ Cr 1 Mo. The same material combination is used for the tube support plates and the shroud. Optionally the whole unit could be made from Incoloy 800 should a detailed stress analysis show bimetallic welds to be critical.

For the pressure shell a steel similar to the SA 533 Grade A Class 1 is recommended.

...

San Francisco

To Bechtel Group Inc., San Francisco

Price:

We have estimated the price for 8 units, including engineering, to be in the order of \$ 52 million. This is for the HP steam generator as shown on the drawing 2-103.074.400, (price basis 1981).

The price does not include external collectors, control systems, valves, flash tanks ,etc.

A second set of 7 similar units could probably be 10 - 15% less expensive.

2. LP-Steam Generator (1 unit)

Since one figure is missing to determine the apparatus we have assumed the feedwater temperature to be 149°C. The helium mass-flow is taken to be 5.2×10^5 lb/hr as specified in the data list, although we could not explain the difference between this mass-flow returning from the coal gasification plant and the massflow of 1.224×10^6 lb/hr being supplied to it.

Thermal lay-out:

The thermal data for this unit are as follows:

Thermal power transferred	118.2 MW
Helium:	
inlet temperature	691°C
inlet pressure	56 bar
outlet temperature	343°C
pressure drop	0.45 bar
massflow	65.5 kg/s
Water/steam:	
FW temperature	149°C
FW pressure	56 bar
steam temperature	343 °C
steam pressure	45 bar
massflow	48.6 kg/s

Adding the parasitic losses of 0.2 to 0.3 bar to the "active" helium pressure drop, the pressure drop is within the allowed limits. Water/steam side pressure drop includes orificing.

Design:

The design is basically the same as for the HP-steam generator. There is, however, only one bundle with a normal tube pitch since the helium inlet temperature is at a "conventional" level and tube sheets are used for water and steam collectors. The dimensions are shown on the enclosed drawing 3-103.074.401.

...

San Francisco

To Bechtel Group Inc., San Francisco

Note: The temperature difference between gas and water/steam is extremely large resulting in high stresses particularly due to differential thermal expansion of tubes and tube support structures. If this unit was designed to produce HP-steam the advantage would be twofold: more efficient use made of the available helium temperature and reduced effort in stress analysis and design.

Material:

2½ Cr 1 Mo is used throughout.

Price:

We have estimated the price of this unit to be in the order of \$ 5.2 million. This is for the LP-steam generator as shown on drawing no. 3-103.074.401 (price basis 1981), with control systems, valves, flash tanks, etc. not included.

Due to the extensive analytical work required a second identical unit would be by approximately 40% less expensive.

3. Comments on Conceptual Heat Cycle

As pointed out above the helium inlet temperature to the HP-steam generator is unusually high. Other than with fossil fired boilers the forced gas circulation improves the gas side heat transfer and thus moves the tube temperature considerably above steam temperature. The temperature gradient over the tube wall becomes large and increases thermal stresses.

For the generation of steam of more or less conventional conditions the advantage drawn from a high helium temperature is marginal. A reduction in size and weight is opposed to increased material, design and stress problems. These latter factors may well outweigh the advantage of compactness, particularly in a case where the apparatus is not integrated within the expensive environment of a PCRV.

A plant that converts about 80% of the power into electricity should in our opinion be primarily designed with regard to this application rather than with priority given to the 20% of process heat.

Obvious alternatives to the proposed heat cycle are:

- to reduce helium IHX exit temperature (now at 1460°F) and include a fossil helium heat at the gasification plant. This would probably also have a cost reduction effect on the hot helium supply line.

...

San Francisco

To Bechtel Group Inc., San Francisco

- to foresee a helium recirculation from steam generator outlet to inlet in order to mix hot helium with about 20% of cold helium.
- to integrate the steam generator within the primary circuit behind a small IHX.

In this context we want to mention that we are involved in the German PNP process heat program as contractor for the IHX development.

I hope that above information will be helpful to you.

I shall be happy to provide you with any additional information which you may require.

Yours sincerely,
SULZER BROS. INC.

Edy O. Sennhauser

Enclosure:

drawings as mentioned:

2-103.074.400 (2 x)

3-103.074.401 (2 x)

Ref. list steam generators 4.1,2,3. (2 x)

28.39.03 (2 x); 28.46.03 (2 x)

3.62 (2 x)

APPENDIX P - ATTACHMENT 11

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May 13, 1981
GA/BNI-027-81
Proj. #7500
WBS 7582080100

Mr. J. E. Leary
~~Technical National Inc.~~
50 Beale Street
San Francisco, CA 94119

Subject: BNI Inquiry on Helium Heated Steam Generator

Ref.: Letter from BNI to GA (R. N. Quade) dated April, 1, 1981

Dear Jack:

We have reviewed your inquiry on the helium heated steam generator and offer the following technical comments on the design condition:

The conditions provided are very similar to the PH-HTGR plant, except that since there is no reformer in the circuit, the steam generator receives a very high helium inlet temperature (1460°F) from the IHX. It would be preferable if this temperature could be reduced to 1250-1300°F to avoid making structural members of expensive exotic materials such as Inconel 617. Also, high inlet gas temperatures require that the heat transfer rate be spoiled at the high temperature end to avoid excessive temperatures and gradients in the tubing; this will increase the complexity and cost of the steam generator design.

There are two ways to reduce the inlet temperature; first, attemperation. The inlet gas can be mixed with outlet gas downstream of the circulator. This will increase the mass flow through the steam generator (mass flow through the IHX is unchanged) by approximately 30% resulting in either greater pumping requirements or an 48% larger diameter heat exchanger. Second, a gas reheat cycle. This solution provides a reheater up stream of the main steam unit thus lowering gas temperatures. Such a concept requires a separate bundle and gas velocity and heat flux will have to be carefully controlled. Also, high temperature tube supports will be required. However, a reheater bundle will be small and the tubing, although fairly hot, will have lower pressure stress than the main steam tubing and thus should be able to handle higher temperatures and gradients. Although this method is more costly than attemperation, it will provide a more efficient cycle (1000°F HP/1000°F LP). Design conditions would be analogous to Fort St. Vrain (1425°F gas inlet at design conditions), but more severe.

Mr. J. E. Leary

- 2 -

May 13, 1981

In either the attemperation or reheat cycle, a main steam unit similar to that shown on*Drawing 026871 would be selected. The reheater would probably be a straight tube cross-counter flow concept with a rectangular bundle inside a round shell. Materials of the main steam unit would be as shown on Drawing 026871 while the reheaters would have Alloy 800 for the tubing and tubesheet, I-617 for tube supports, gas guide and seals at the hot end, and low alloy material for the internally insulated shell and cold tubesheet.

If it is necessary to live with the high temperatures in the main steam unit, a new design would be required. It would have a split helical bundle with I-617 shrouds and tube supports. The Alloy 800H material would have to extend into the boiler because of the high gas temperature. The tubing in the high temperature bundle would be spread apart to spoil the heat transfer rate. Expansion loops would be difficult to design because of the necessity to shield them from the flow.

The data provided for the HP steam generator shows a different Q for the helium and steam flows. Holding the outlet steam temperature and steam and helium mass flows together with the given helium Δt , the feedwater inlet temperature should be 350°F rather than 450°F. Also the allowable ΔP on the helium side of 30 PSI seems excessive. We usually use about 8 PSI.

Steam mass flow and required temperature rise was not provided in the LP conditions and, therefore, it is not clear what the preferred concept should be. If the mass flow is large and the temperature rise is small (large number of tubes, short length), a straight tube cross-counter flow would be selected. If the mass flow is small and the temperature rise is large (few tubes, very long) a helical coil would be preferred. (U-tube would probably not work because of excessive Δt while a bayonet would have a too large tubesheet and high helium side ΔP . Note that traditional fossil plant boiler concept does not apply because of the high helium pressure).

Note that because these components are in the secondary loop outside the PCRV, we believe they can be built to Section VIII, Div. 1 Code with lower seismic requirements which will reduce costs.

We will be providing a cost for steam generator shown on our drawing as part of the DOE work, and it may serve as a guide for the cost of the unit needed for the CCG process.

If we can help you further on the subject, please let me know.

Sincerely,

R. N. Quade
Project Manager

RNQ:bk

* Please note that drawing 026871 is being sent under separate transmittal PH/GCRA-013-81 to GCRA with copy to BNI

bcc: E. Hurn
J. Kissinger
C. McDonald
C. Peinado

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