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CHARACTERIZATION OF ALTERNATIVE ELECTRIC GENERATION TECHNOLOGIES FOR THE SPS COMPARATIVE ASSESSMENT: VOLUME 2 CENTRAL-STATION TECHNOLOGIES

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ABSTRACT

The SPS Concept Development and Evaluation Program includes a comparative assessment. An early first step in the assessment process is the selection and characterization of alternative technologies. This document describes the cost and performance (i.e., technical and environmental) characteristics of six central station energy alternatives:

- Conventional Coal-Fired Powerplant
- Conventional Light Water Reactor (LWR)
- Combined Cycle Powerplant with low-Btu Gasifiers
- Liquid Metal Fast Breeder Reactor (LMFBR)
- Photovoltaic System without Storage
- Fusion Reactor

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SECTION 1. INTRODUCTION

1. INTRODUCTION

1.0 BACKGROUND

The SPS Concept Development and Evaluation Program (CDEP)* was established by the Department of Energy and the National Aeronautics and Space Administration to generate information from which a rational decision cound be made regarding the direction of the Satellite Power System (SPS) program after fiscal 1980. The comparative assessment program is one of four functional areas within the joint DOE/NASA-CDEP. The other CDEP functional areas are:

- Systems Definition: SPS reference** and alternative concept designs
- Environmental Assessment: evaluation of environmental impacts (e.g., health & safety, ecological) of the SPS operation
- Societal Assessment: evaluation of international issues, institutional issues, resource issues and public outreach

The results of these three activities are inputs to the comparative assessment process, as well as to program assessments.

1.1 COMPARATIVE ASSESSMENT AND ALTERNATIVE CHARACTERIZATION

The objective of the comparative assessment is to develop an initial understanding of the SPS with respect to a limited set of energy alternatives. A comparative methodology report describes the multi-step process in the comparative assessment. The first step is the selection and characterization of alternative energy systems. Terrestrial alternatives are selected, and their cost, performance, and environmental and social attributes are specified for use in the comparison with the SPS in the post-2000 era. Data on alternative technologies were sought from previous research and from other comparisons.

The objective of this report is to provide a traceable characterization of the cost and performance (i.e., environmental and technical) of competing

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*Satellite Power System (SPS) Concept Development and Evaluation Program Plan, DOE/ET-0034 (February 1978).

**U.S. Department of Energy and NASA, SPS CDEP Reference System Report, DOE/ER-0023 (October 1978).

technologies. The following central station technologies have been selected for comparison:

- Conventional Coal-Fired Powerplant
- Conventional Light Water Reactor (LWR)
- Combined Cycle Powerplant with low-Btu Gasifiers
- Liquid Metal Fast Breeder Reactor (LMFBR)
- Photovoltaic system without storage
- Fusion Reactor

Volume 3 of the technology characterization report describes a rooftop decentralized photovoltaic option that was also compared to SPS.

1.2 BASIC ASSUMPTIONS AND DATA BASES

The technologies listed in Section 1.2 either exist currently or have proven principles of operation with one exception: the fusion reactor. The fusion reactor will probably not be ready for commercial operation by the year 2000. Best estimates call for a fusion reactor ready by the year 2020 or later depending on the pace and success of current R&D programs. However, for comparative purposes, the fusion reactor has been included in this report.

The primary data base used for this report was "Satellite Power System and Alternative Technology Characterization," UE&C-ANL-790831, prepared by United Engineers and Constructors. In this document, UE&C prepared characterizations and prepared estimates of the costs of the various technologies under consideration. The units characterized by UE&C were standard sizes and represented the technology of the mid-1970's. However, for the purposes of this report, these technologies were scaled to a common size (1250 MWe) and extrapolated to the year 2000. Scaling of the units, a fairly routine practice, is discussed in the individual sections. Extrapolation of the units to the year 2000 is more difficult.

- The primary advances in nuclear technology will be related to safety equipment and systems, rather than performance enhancement advances.
- The LMFBR and fusion reactors represent new technologies and nothing beyond the first generation configurations is assumed.

- Continued tightening of EPA emission and effluent standards will bring advances in pollution control equipment. A Wellman-Lord Flue Gas Desulfurization system is assumed for the coal-fired powerplant. Enhanced air emissions control equipment is also assumed for the combined cycle unit. Magnetohydrodynamics and large-scale fluidized bed combustion are not assumed to be ready by the year 2000.
- Photovoltaic technology will produce ribbonlike cells, thus allowing closer packing factors than would be achievable by the round cells. In addition, the price of PV cells is assumed to continue its downward trend.
- Design and construction codes, standards, regulations and guidelines applicable around 1975-1976 represent those in effect for the powerplant in 2000 escalated at the rate of inflation plus 10%.

Other assumptions made for the technology characterizations are addressed in the individual sections.

All of the characterized power stations are located on a suitable site near "Middletown, USA." The site has a major freshwater river flowing next to the plant site to provide makeup and, in essence, is ideal for a powerplant. None of the technology characterizations presented in this report has been optimized. Rather, they describe in general terms what a powerplant would look like if that technology were developed. Despite this lack of an optimized design, the cost estimates are considered valid for comparative purposes. The estimates are believed to lie within the limits of estimating techniques for periods that extend 20 years into the future for technologies which may or may not have been fully developed.

SECTION 2. CONVENTIONAL COAL FIRED POWERPLANT

2. CONVENTIONAL COAL FIRED POWERPLANT

1.0 CONVENTIONAL HIGH SULFUR COAL COMBUSTION WITH ADVANCED FLUE GAS DESULFURIZATION

The reference, high-sulfur coal combustion system is a single-unit facility. The steam plant uses a cross compound, two parallel-shaft turbine generator, and has a net plant capacity of 1250 MWe. The basic steam cycle is modeled after a 1232 MWe concept designed by United Engineers and Constructors, as described in their reports "Commercial Electric Power Cost Studies,"[(1)] and "Satellite Power System and Alternative Technology Characterization."[(2)] The United Engineers' design utilizes a conventional lime flue gas desulfurization system for stack gas cleaning and a mechanical draft cooling tower for condensate heat removal. At the time of its design (1977), this system met the Environmental Protection Agency (EPA) new source performance standard (NSPS) for SO_2 emissions of 1.2 $lb/10^6$ Btu by scrubbing about 88% of the flue gas at a 90% removal efficiency. More recent EPA regulations require a 90% removal of all SO_2 stack gas for a facility of this type, and total SO_2 are not to exceed an upper limit of 1.2 $lb/10^6$ Btu.[(3)]

The characterization provided here is that of a projected year (2000), high-sulfur coal combustion technology and SO_2 removal process. The plant capacity factor is assumed to be 70%. It is also assumed that all of the plant's stack gases are processed to remove 90% of the SO_2. Although it is possible to achieve this removal efficiency with conventional wet lime scrubbers, we considered advances in SO_2 removal systems anticipated between now and the year 2000. Thus, the reference high-sulfur coal facility for the year 2000 is assumed to use a Wellman-Lord SO_2 removal system. The Wellman-Lord process has recently been demonstrated by the EPA[(4)] and it is expected that this or a similar technology will be the preferred option in the year 2000 time frame. The Wellman-Lord system reduces land area requirements, the assumption of processing all stack gases decreases the net plant efficiency. Thus, the plant capital costs relative to the United Engineers design is increased. These factors have been fully accounted for in the characterization provided here.

2.0 GENERAL PLANT CONFIGURATION

Figure 2-1 shows the basic plot arrangement for the reference, high-sulfur coal facility. The predominant structures are identified: the boiler house, turbine hall, and SO_2 removal area. Two circular mechanical draft cooling towers and the electrical switchyard are located several hundred feet from the main generation facility. The largest onsite area is the coal storage piles which typically store a total of 60-day coal supply,[5] 5% of which is considered active storage. The remainder is held as reserve, or dead storage, to guard against mining strikes or other supply interruptions. Other onsite structures include access roads, railroad spurs, and miscellaneous storage tanks and settling basins. The layout shown includes site provisions for an optional doubling of the plant capacity in the future. Space requirements for these additional facilities are shown by the broken lines on the plot plan.

Although the elemental sulfur produced as a byproduct of the Wellman-Lord SO_2 removal system could be a marketable commodity, this characterization assumes that the market conditions for sulfur are unfavorable and that the sulfur byproduct is disposed of in an appropriately prepared disposal site remote from the primary plant site.[6] Land area requirements for the primary site and sulfur disposal are discussed later in this section.

Coal is delivered via unit train to the fuel handling area adjacent to the coal storage piles. The fuel handling system has all of the necessary equipment to handle the coal gondolas in which the coal is supplied, including facilities for thawing the cars in winter and rotary car dumper. From the storage piles, the coal is moved by front end loaders to a conveyor system and on to the dryers, crushers, and pulverizers before being fed to the combustion furnace boilers along with preheated air. High pressure steam produced in the boilers is used to power the turbine generator equipment to produce a net plant capacity of 1250 MWe. Flue gases are processed through electrostatic precipitators to remove 99.7% of the flyash particulates and through a Wellman-Lord SO_2 removal system before being reheated with an in-stack, steam-to-flue gas heat exchanger and discharged to the atmosphere through a 750 foot high, steel-lined stack.

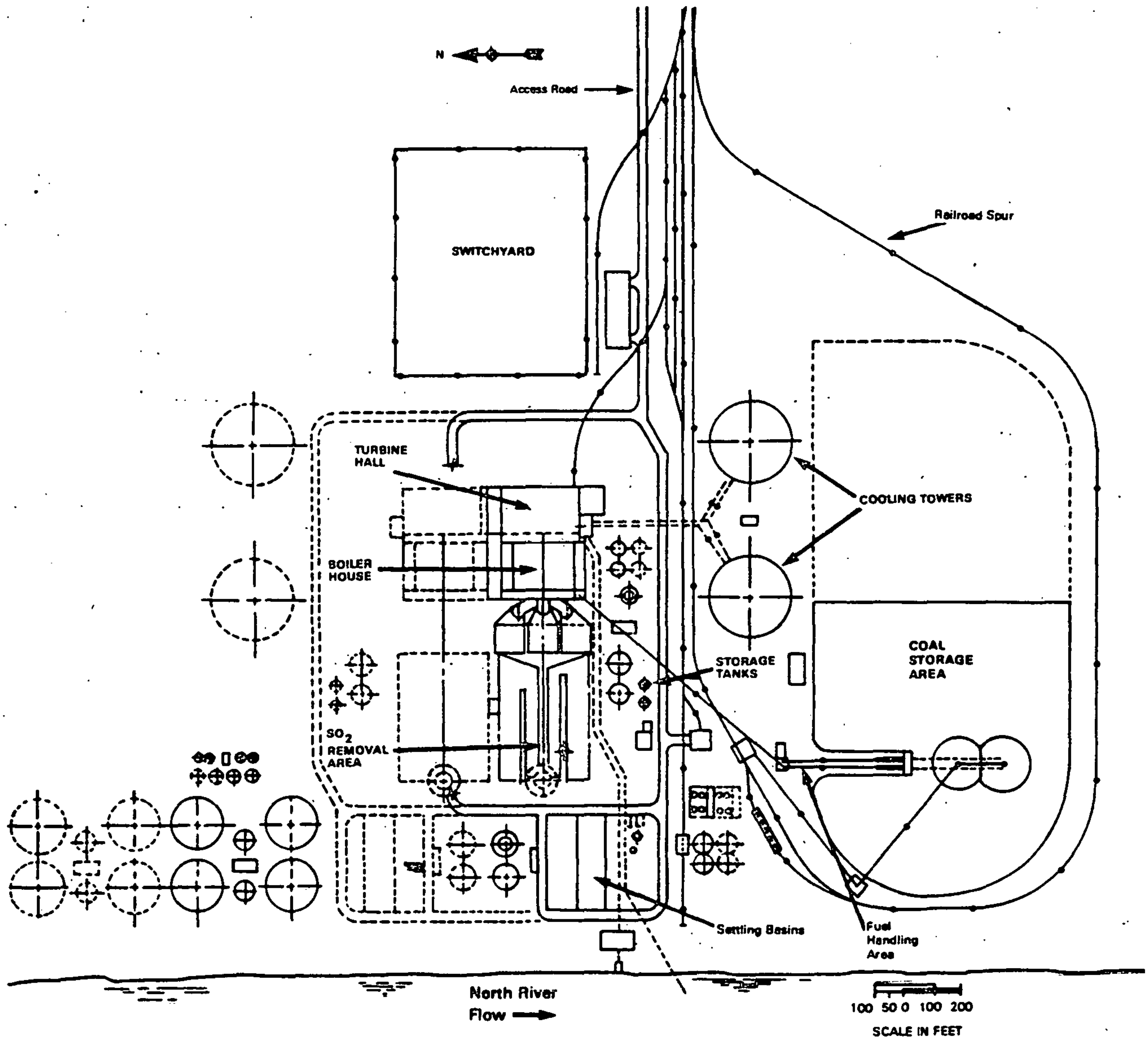


Figure 2-1. Plot Plan - 1250 MWe Reference High Sulfur Coal System

Boiler solid waste, bottom ash, is removed by an ash handling system. Afterwards, the waste is quenched and combined with the flyash. Then the ash sludge is routed to an onsite settling pond for temporary storage and dewatering. Finally, the ash sludge and the elemental sulfur are removed from the SO_2 removal system.

The main condenser heat rejection system includes a makeup water intake and discharge, circulating water pump, and two mechanical draft wet cooling towers. Waste heat from the thermodynamic cycle is rejected to the main condenser in the form of heated water. Cooler water from the cooling towers circulates through the condenser to remove this heat and rejects it to the atmosphere in the form of convective and evaporative losses.

3.0 THERMODYNAMIC CYCLE CHARACTERISTICS[7]

The reference, high-sulfur coal generation facility is fired with an Eastern bituminous coal which, as received, has a higher heating value (HHV) of 11,026 Btu/lb and other constitutents as shown in Table 2-1. The overall net plant efficiency, which accounts for in-plant auxiliary steam and electrical consumption, is 35.75. This facility requires 9546 Btu's of coal feed to produce one kilowatt hour of electricity. Figure 2-2 displays the major pieces of plant equipment in a simplified cycle schematic and energy flow diagram of the reference design. Each of the major components is described in the following paragraphs.

3.1 COMBUSTION FURNACE BOILER

With a pulverized coal feed of 11,932.7 x 10^6 Btu/hr, or 541.1 tons/hr at 11,026 Btu/lb, the combustion furnace boiler produces 9.69 x 10^6 lb/hr of high-pressure steam at 3845 psig and 1010°F at the superheater outlet. This is accomplished using an equivalent flow of feedwater at a temperature of 547°. Exit steam from the boiler is expanded through the high-pressure turbine which has steam inlet conditions of 3515 psig and 1000°F. A total of 7.93 x 10^6 lb/hr of steam at 565°F and 653 psig is removed from the high-pressure turbine outlet and returned to the boiler steam reheaters where it is heated to 1000°F and 600 psig before it is expanded through the intermediate pressure turbine. Exit steam not returned to the boiler reheaters, approximately 1.76 x 10^6 lb/hr, is extracted at 672°F and used primarily for feedwater heating.

Total heat to steam in the boiler and reheaters is 10,560 x 10^6 Btu/hr on a coal feed of 11,932.7 x 10^6 Btu/hr, or an 88.5% boiler/reheater efficiency. Boilers of similar characteristics and heat-to-steam efficiencies are currently marketed by Combustion Engineering and other major boiler manufacturers.

3.1.1 Turbine Generator Configuration

Turbine shaft power totaling 4735.2 x 10^6 Btu/hr or 1,387,400 kW is produced with throttle steam conditions of 3515 psig and 1000°F superheated steam (at the inlet to the high pressure turbine) and 600 psig at 1000°F (at the inlet to the intermediate pressure turbine). The turbine configuration is a cross compound: two parallel-shaft machines with an eight flow low-pressure

Table 2-1. Typical Eastern High Sulfur Coal Characteristics

Property or Component	As Received	Dry
Higher Heating Value	11,026 Btu/lb	12,432 Btu/lb
Ultimate Analysis (% by Weight)		
Carbon	61.49	69.33
Hydrogen	3.81	4.30
Sulfur	3.20	3.61
Nitrogen	.76	.86
Oxygen	8.55	9.64
Other	.59	.66
Ash	10.29	11.60
Moisture	11.31	-
	100.00	100.00
Ash Analysis (% by Ash Weight)		
P_2O_5		.05
Si O		45.73
Fe_2O_3		18.38
Al_2O_3		19.40
Ti O_2		1.30
CaO		5.50
MgO		.95
SO_2		6.63
K_2O		1.53
Na_2O		.51
Undetermined		.02
		100.00

Source: Reference 2, P. 2.2-5

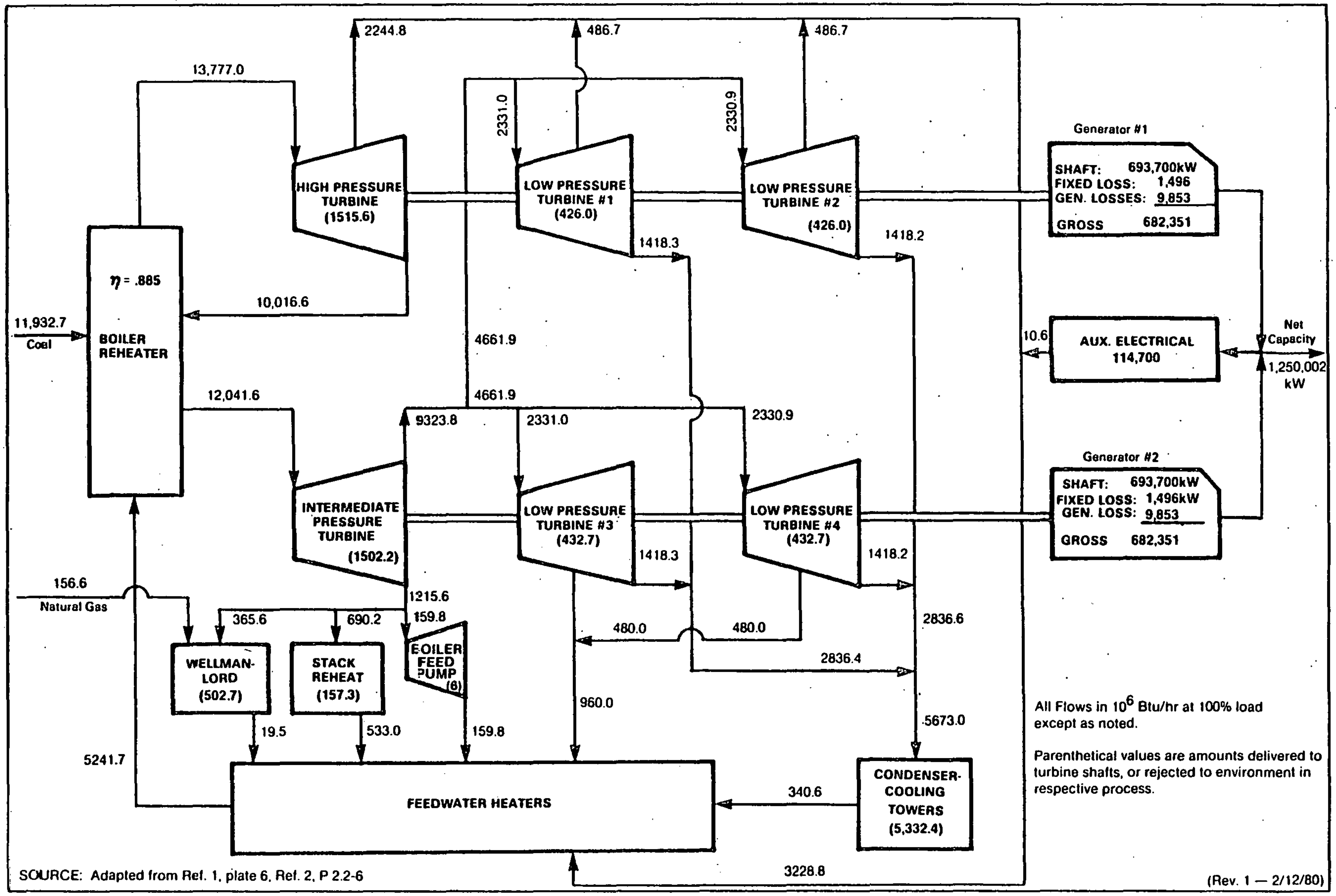


Figure 2-2. Simplified Schematic of High-Sulfur Coal Generation Facility

turbine exhausting to the condenser (four only, as shown previously in Figure 2-2 schematic) and using 30-inch last-stage turbine blades designed for 3600 revolutions per minute (rpm). As shown in Figure 2-2, one shaft consists of one high-pressure turbine and two low-pressure turbines driving an electric generator. A second, parallel shaft consists of one intermediate-pressure turbine and two low-pressure turbines driving an electric generator.

Turbine shaft power and generator output is about equally distributed to the two shafts. Each of the two generators is rated at 722 MVA with 0.90 PF, 26,000 V, 3 phase and 60 Hz output. Fixed and generation losses respectively account for 1,496 kW and 9,853 kW per generator, thus resulting in a gross generator output capacity of 1,364,702 kW, before accounting for auxiliary electrical loads.

The steam flow configuration through the turbines begins with high-pressure steam entering the high-pressure turbine on the upper shaft displayed in Figure B-2. As this steam is expanded through the turbine, it imparts about 1515.6 x 10^6 Btu/hr (444,066 kW) to the turbine generator shaft. Some 18% of the inlet steam flow is extracted and used in the final feedwater heating stage, with the remainder (82%) being returned to the boiler reheaters.

From the boiler reheaters, intermediate-pressure steam is expanded through the intermediate-pressure turbine on the lower turbine generator shaft. There, 1502.2 x 10^6 Btu/hr (440,140 kW) is given up to the turbine shaft before being extracted for various in-plant uses or as feed streams to the four low-pressure turbines. The various in-plant steam uses primarily include 161.18 x 10^6 Btu/hr to power the boiler feed pump turbine, 365.6 x 10^6 Btu/hr to convert sodium bisulfate to sodium sulfite in the Wellman-Lord SO_2 removal system, and a net of 157.3 x 10^6 Btu/hr to reheat about 13.0 x 10^6 lb/hr of stack gases from 125°F to 175°F. As shown in the figure, residual energy from these auxiliary steam flows is then used for feedwater heating.

Twenty-five percent of the remaining 9,323.8 x 10^6 Btu/hr of steam, which was extracted from the intermediate pressure turbine at its final stage outlet, is used to power each of four low-pressure turbines. The low pressure turbines on the upper (or high-pressure) turbine shaft each receive 426.0 x 10^6 Btu/hr (124,817 kW) of energy at the turbine shaft and reject 1.430 x 10^6 Btu/hr to the condenser. Low-pressure turbines on the lower or intermediate-pressure turbine shaft each receive 432.7 x 10^6 Btu/hr (126,780 kW) at the turbine shaft and reject about the same amount of waste heat to the condenser system. Low pressure turbine steam energy not imparted to the turbine shafts or rejected to the condenser is extracted and used primarily for feedwater heating.

3.1.2 Condenser-Heat Rejection System

Two multipressure, single pass surface condensers--with divided fabricated steel water boxes and shell--are used to condense the low-pressure turbine outlet steam by dissipating to two mechanical draft wet cooling towers. Each cooling tower is sized for one-half of the heat rejection requirements. Designed to cool 231,400 gallons per minute from 118°F to 92°F for a wet bulb temperature of 74°F, each cooling tower houses 13 fans measuring 33 feet in diameter. Under full load conditions 95% of the heat dumped to the condenser, or 5332.4×10^6 Btu/hr, is rejected to the atmosphere by the cooling water system.

3.1.3 Feedwater Heaters

Feedwater flow from the condenser enters a series of eight reverse cascade feedwater heaters designed to achieve a final feedwater flow of 9.69×10^6 lb/hr at 547°F. As mentioned previously, numerous turbine extractions and other residual steam flows are utilized in the feedwater heating stage of the steam cycle. A total of 4901.1×10^6 Btu/hr is added to the condenser outflow of 340.6×10^6 Btu/hr resulting in 5241.7×10^6 Btu/hr final feedwater flow to the boiler. A small amount of energy is also added to feedwater steam from electrical pump thermal losses particularly from the condensate and condensate booster pumps.

3.1.4 Generator Losses and Auxiliary Electric Energy Use

Aggregate turbine shaft power totals 1,387,400 kW. Various generator inefficiencies result in the loss of 22,698 kW or 1.64% of the shaft power as fixed and generation power losses. Of the remaining 1,364,702 kW, a total of 114,700 kW or 8.40% is used for auxiliary electrical uses within the plant, leaving 1,250,014 kW of net plant generation. Table 2-2 details the auxiliary power requirements for the reference, high-sulfur coal facility.

The fractional power requirement for in-plant auxiliary electrical uses is somewhat higher than what is typically reported for conventional coal generation facilities. The primary reason for this is the high power requirements for the electrostatic precipitators and the Wellman-Lord flue gas

Table 2-2. Auxiliary Electric Power Requirements Reference 1250 MWe High-Sulfur Coal Facility

Auxiliary	MWe	
Combustion Furnace Boiler		63.2
Forced Draft Fans	21.1	
Pulverizer Air Fans	6.3	
SO_2 Booster Fans and Damper Fans	9.8	
Soot Blower Compressor	5.5	
Electrostatic Precipitators	13.9	
Crushers and Pulverizers	6.6	
Turbine Auxiliary		4.5
Wellman-Lord SO_2 Removal		25.4
Major Pumps		12.2
Condensate Booster	2.0	
Condensate	.7	
Circulating Water	9.5	
Water Intake and Discharge		.7
Solids Handling		3.2
"Hotel"* Loads		2.5
Cooling Tower Fans		3.0
TOTAL		114.7 MWe

*Miscellaneous plant loads not itemized, based, in part, on an analysis of Nuclear plant Hotel loads. Reference 9.

Source: Adapted from Reference 1 and Reference 9 desulfurization system. For example, conventional wet-lime scrubbers would need about 11.3 MWe for a plant of this size. The Wellman-Lord system, however, has a power requirement of 25.4 MWe. Also, the electrostatic precipitators (ESP) for flyash removal have been sized for 99.7% flyash removal efficiency as opposed to a more conventional removal efficiency of 98.6%. As power requirements for ESP flyash removal are proportional to log (1-f) where f is the fractional collectional efficiency, the assumed increase of 1.1% collection efficiency increases the ESP power requirement by slightly more than 36% over the conventional system requirements.[8] Other factors which tend to increase inplant power uses result from added steam, air, and coal handling requirements that are necessary to support the auxiliary steam uses for stack gas reheating, and the Wellman-Lord SO_2 removal system, as well as the gross flows needed to support the added inplant electrical uses. Added steam and air and material flows increase inhouse power requirements for fans, pumps, and solids handling equipment by 5.2% to maintain the same net generation capacity.

3.1.5 Fuels Use and Logistics

The reference, high-sulfur coal generation facility uses a typical eastern high-sulfur bituminous coal to generate a net capacity of 1250 MWe with an assumed capacity factor of 70%. A detailed heat balance shows that 9,546 Btu's of pulverized coal is required to generate one net kilowatt hour of net output; this corresponds to a net plant efficiency of 35.75%. The coal characteristics chosen assume a higher heating value of 11,026 Btu/lb of coal on an as-received basis. At full capacity, coal feed is required at a rate of 541.1 tons/hour or 3.32×10^6 tons/year at 70% capacity factor. At this rate, an average of 9,090 tons of coal would be delivered to the site each day. Because coal storage requirements are estimated at full capacity factor, a 3-day live storage stock pile would contain 38,960 tons of coal, and a 57-day reserve storage would contain 740,225 tons of coal.

The average storage density of utility coal in live storage is 960 tons/acre-ft, and reserve storage density averages 1176 tons/acre-ft.[10] These data assume that 30 foot high active storage and 50 foot high reserve storage results in a site area of 14 acres devoted to coal storage alone.

Other fuel in the form of natural gas is also required for processing SO_2 gas from the Wellman-Lord scrubber system to elemental sulfur. This process requires about 156.6 x 10^6 Btu/hr of natural gas at full plant capacity or, at 70% capacity factor and 1,000 Btu/ft^3 of gas, about 960.3 x 10^6 ft^3 of natural gas per year.[11] This fuel requirement is discussed in more detail under the description of the Wellman-Lord flue gas desulfurization system. Table 2-3 summarizes some of the reference plant parameters.

Table 2-3. Key Plant Parameters - 1250 MWe High-Sulfur Coal Plant

Parameters	Operating Description
Steam Generator	Supercritical pressure, single reheat with a Pressurized Furnace
Steam Flow	
Maximum Continuous Rating, 10^6 lb/hr	10.36
Normal Superheater Outlet, 10^6 lb/hr	9.69
Normal Reheater Outlet, 10^6 lb/hr	7.93
Steam Pressure	
Superheater Outlet, psig	3,845
Reheater Outlet, psig	650
Steam Temperature	
Superheater Outlet, °F	1,010
Reheater Outlet, °F	1,000
Final Feedwater Temperature, °F	547
Fuel Type	Eastern Bituminous Coal @ 11026 Btu/lb, 10.29% ash, 3.2% sulfur
Fuel Firing Rate, Ton/Hr at full load	541.1
Fuel Analysis	See Table B-1
Number of Pulverizers	6 plus 1 spare
Pulverizer Fuel Flow, Tons/Hr	90.2
Number of Forced Draft Fans	3 3
Total Forced Draft Fan, Capacity, scfm	2,160,000
Number of Primary Air Fans	2
Total Primary Air Fan Capacity, scfm	540,000
Number of Precipitators	3
Precipitator Efficiency, in percent	99.7
Turbine Configuration	Cross Compound, 8 Flow
Steam Flow at HP Turbine Inlet, 10^6 lb/hr	9.69
Steam Pressure at HP Turbine Inlet, psia	3,515

Table 2-3. Key Plant Parameters - 1250 MWe High-Sulfur Coal Plant (Continued)

Parameters	Operating Description
Steam Temperature at HP Turbine Inlet, °F	1,000
Turbine Back Pressure, in HgA (multi-pressure condenser)	1.7/2.5
Total Turbine Output, MWe	1,387.4
Fixed and Generator Losses, MWe	22.7
Generator Output, MWe	1,364.7
Auxiliary Power, MWe	114.7
Net Station Output, MWe	1,250.0
Number of Feedwater Heating Stages	8
Generator Rating, MVA	722
Net Station Primary Steam Rate, lbs/kWhr	7.75
Gross Station Heat Rate, Btu/kWhr[1]	8,743.8
Net Station Heat Rate, Btu/kWhr[2]	9,546
Gross Plant Efficiency, in percent[1]	39.03
Net Plant Efficiency, in percent[2]	35.75

(1) Gross is before auxiliary electric uses

(2) Net is after auxiliary electric uses

Source: Adapted from References 1, 2, 12.

4.0 ENVIRONMENTAL CHARACTERISTICS

4.1 ELECTROSTATIC PRECIPITATORS

The reference, high-sulfur coal facility has been designed with hot electrostatic precipitators sized for the removal of 99.7% of the flyash particulates emitted from the combustion furnace boiler. The flow rate of the flue gas processes is approximately 13 x 10^6 lb/hr at full load. Thus, 13.9 MW of auxiliary electric power is required for effective operation of the electrostatic precipitators.[8, 12, 13]

The combustion of 1,082,233 pounds of coal per hour with an ash content of 10.29% by weight produces 89,089 lb/hr of flyash based on an 80% flyash, 20% bottom ash (22,273 lb/hr) proportion. Removal of 99.7% of this amount results in a total of 267 lb/hr of flyash, which is sent downstream for further processing in the Wellman-Lord SO_2 removal system.

Flyash removed by the precipitators is quenched with water combined with the bottom ash and disposed of as 20% water, 80% ash solids.[14] Thus, the sludge wastes from the electrostatic precipitators and bottom ash totals 138,869 lb/hr for the 1250 MW reference coal facility at 100% capacity.

It should be noted that the electrostatic precipitators assumed to be installed in this reference facility could easily meet current EPA standards for particulate emissions without further processing of particulates in the initial stage of the Wellman-Lord system. The 267 lb/hr of flyash in the electrostatic precipitator exit stream corresponds to the combustion of 11,932.7 x 10^6 Btu of coal or an exit stream particulate rate of 0.022 lb/10^6 Btu. Current EPA regulations call for particulate emissions not greater than 0.03 lb/10^6 Btu.

To meet current EPA regulations for particulate emissions after an additional 70% removal is achieved in the Wellman-Lord system, the electrostatic precipitators need to be designed to remove only 98.7% of the flyash particulates. This reduction in collection efficiency would have a corresponding reduction in in-house auxiliary power requirements of 3500 kW (or about 3% of what is currently assumed for the reference facility). Thus, the design characteristics assumed here, which are achievable with current technology, are conservative in terms of their affect on the plant heat rate and costs.

In other words, these assumptions tend to reduce overall plant efficiency and thus increase total generating costs.

4.2 WELLMAN-LORD FLUE GAS DESULFURIZATION

Downstream from the electrostatic precipitators is the Wellman-Lord flue gas desulfurization system. This system uses a regenerable process in which sulfur dioxide, SO_2, is removed from flue gases with a sodium sulfite scrubbing solution. The concentrated SO_2 stream that is produced can be processed into elemental sulfur or sulfuric acid, both of which may be marketable industrial products.

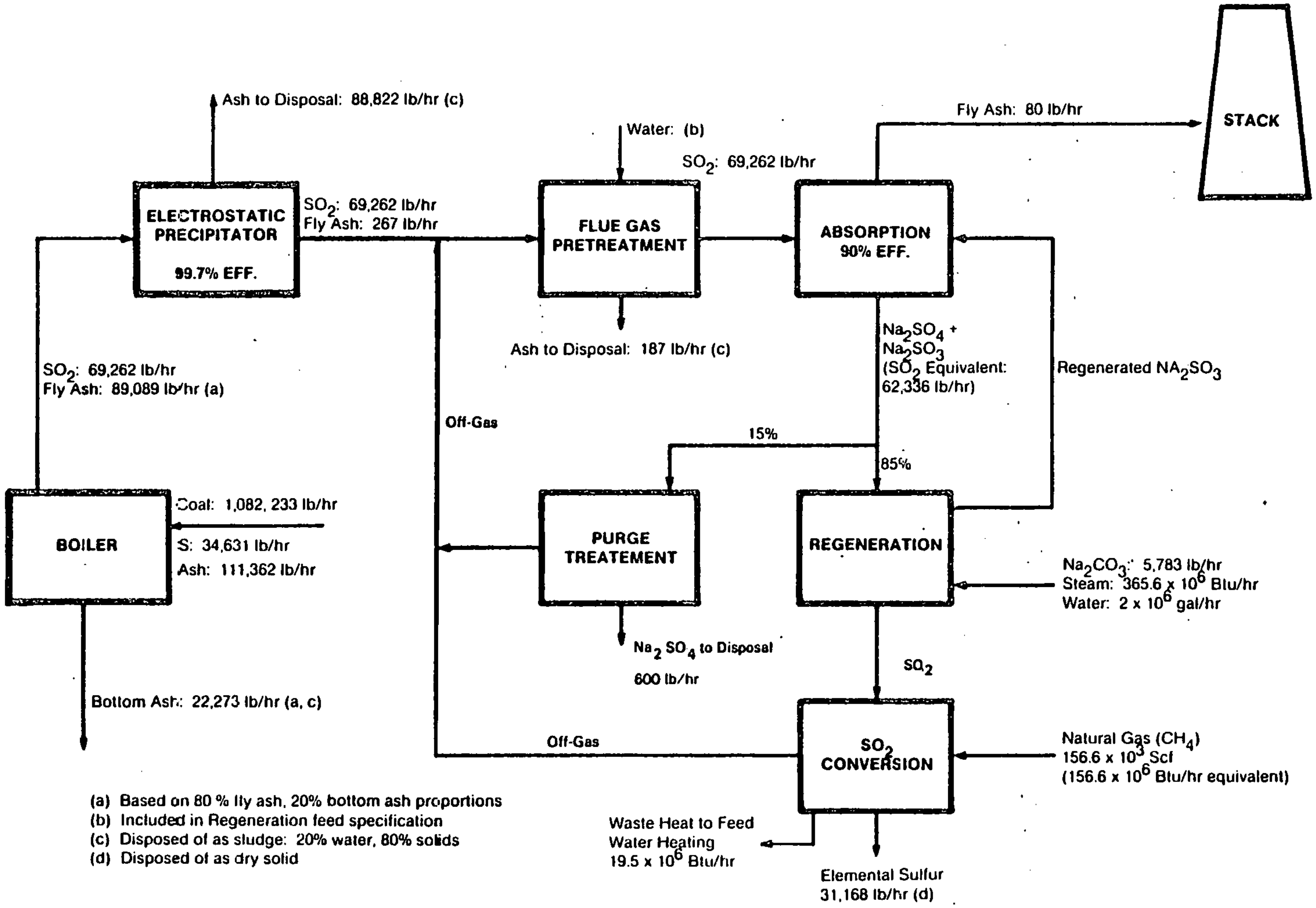
There are currently more than 24 operating Wellman-Lord installations in the United States and Japan. Most notable is the Wellman-Lord installation at the Northern Indiana Public Service Company's P. H. Mitchell Station in Gary, Indiana, which is this Nation's first application of the Wellman-Lord process on a coal-fired boiler. This system is currently demonstrating SO_2 removal efficiencies greater than 90%.

The Wellman-Lord process consists of four basic steps as shown schematically in Figure 2-3. These steps include:

1. Flue gas pretreatment
2. SO_2 absorption
3. Purge treatment
4. Sodium sulfite regeneration

A fifth step, the processing of SO_2 into marketable sulfur byproducts, is not part of the Wellman-Lord process, but is generally associated with Wellman-Lord installations.

In the first process step, boiler flue gas is pretreated by contact with water in a venturi prescrubber. This step cools and saturates the gas, absorbs corrosive chlorides, and then removes 70% or 187 lb/hr of the flyash particulates remaining in the gas after upstream particulate removal by the electrostatic precipitators. This is disposed of as an 80% solids sludge at a rate of 234 lb/hr. Only 80 lb/hr of particulates remain in the flue gas stream after pretreatment in the venturi prescrubber.



(a) Based on 80 % fly ash, 20% bottom ash proportions
(b) Included in Regeneration feed specification
(c) Disposed of as sludge: 20% water, 80% solids
(d) Disposed of as dry solid

SOURCE: adapted from Ref. 4

Figure 2-3. Wellman-Lord Process

After pretreatment, the flue gas then flows to an absorber where it is contacted with a sodium sulfite solution. The SO_2 in the flue gas reacts with the sodium sulfite to produce sodium bisulfite. In a side reaction, some sodium sulfate is formed by direct oxidation of sodium sulfite.

At least 90% of the SO_2 in the flue gas stream is removed in the absorption stage; the remaining 10% is emitted to the atmosphere. Combustion of 1,082,233 lb/hr of coal with a sulfur content of 3.2% and 90% removal results in the emission of 6,926 lb/hr of SO_2, or an equivalent of 0.58 lb/10^6 Btu of SO_2. This desulfurized flue gas leaves the absorber at a temperature of 125°F and is reheated with an instack, steam heat exchanger to 175°F before it is exhausted to the atmosphere.

The effluent from the absorption tower, rich in sodium bisulfate and sodium sulfate, is split into two streams. Approximately 15% of the effluent is routed to a purge treatment for sulfate removal; the remaining 85% goes to a regeneration process.

The purge stream is cooled in a chiller and a mixture of sodium sulfate and sodium sulfite is crystallized out of the solution. This crystalline mixture is removed from the process and dryed for sale or disposal. For the reference 1250 MWe coal facility burning 3.2% sulfur coal, the combined sodium sulfate and sodium sulfite waste would be generated at a rate of 6000 lb/hr.

Although this sodium sulfate/sodium sulfite byproduct has a somewhat limited economic value, a potential market may exist in the paper industry where it may be used to replenish sulfur in the pulping liquor. This characterization, however, assumes that the dryed byproduct is disposed of along with the ash sludge, elemental sulfur, and other waste or byproducts.

Regeneration is accomplished in an evaporator for 85% of the absorption tower outlet stream that goes to the regeneration step. The effluent in the evaporator is heated to convert sodium bisulfate to sodium sulfite and to drive off sulfur dioxide. For the reference coal system, 365.6 x 10^6 Btu/hr of steam is extracted from the steam cycle to provide the necessary heating requirements. The regenerated sodium sulfite is dissolved and recycled to the absorber. Sodium lost during the purge operation is replenished by adding 5783 lb/hr of sodium carbonate and water to the feed dissolving tank.

The fifth step, SO_2 processing, uses the sulfur dioxide byproduct from the Wellman-Lord process. The outlet stream from the regeneration evaporator is about 85% SO_2 and 15% water vapor. This concentrated SO_2 stream may be dried and marketed without further processing. Then the concentrated SO_2 stream is either reduced to elemental sulfur or oxidized and reacted with water to form sulfuric acid. Here, an Allied Chemical Corporation process for conversion of SO_2 to elemental sulfur has been integrated with the Wellman-Lord flue gas desulfurization system. The Allied process would use 156.6 thousand cubic feet of natural gas per hour (156.6×10^6 Btu/hr) as a reductant. A proprietary catalyst converts the SO_2 gas stream to elemental sulfur, thereby liberating carbon dioxide and water. By this process, 31.168 lb/hr of elemental sulfur would be produced at 100% capacity. As mentioned previously, this byproduct is assumed to be disposed of in clay-lined disposal basins rather than marketed.

The conversion of SO_2 to elemental sulfur is an exothermic reaction and would liberate approximately 19.5×10^6 Btu/hr. In the reference coal design, this energy is assumed to be used for feedwater heating. Overall, a 90% removal of SO_2 in the flue gas stream results in the ultimate emission of 6.926 lb/hr of SO_2 to the atmosphere. This emission rate corresponds to 0.58 lb/10^6 Btu of coal burned.

Table 2-4 summarizes the air residuals resulting from power generation of this system. Solid and sludge residuals and the environmental impacts associated with the coal fuel cycle are discussed in the following sections.

Table 2-4. Air Residuals - 1250 MWe Reference High-Sulfur Coal Generation

	100% Capacity Factor		70% Capacity Factor		
Pollutant	lb/hr	tons/yr	lb/hr	tons/yr	lb/10^6Btu
SO_2	6,926	30,336	4,848	21,234	0.58
Particulates	80	350	56	245	0.007
NO_x	7,160	31,360	5,012	21,953	0.6

4.3 SOLID WASTES AND SLUDGES

Solid wastes and sludges result from power generation by the reference, high-sulfur coal facility. This in turn results from the disposal of wastes and byproducts recovered from the flue gas desulfurization and ash recovery systems.

At full capacity, 1,082,233 lb/hr of coal composed of 10.29% ash and 3.2% sulfur is fired in the combustion furnace boiler. A total of 90% of the input sulfur is recovered and disposed of in clay-lined disposal basins near the primary plant site. Thus, at 100% load, 31,168 lb/hr of elemental sulfur is processed for disposal.

Flyash constitutes about 80% of the total ash in the feed coal. Of this amount, 99.7% is recovered in the electrostatic precipitators. Seventy percent of the ash in the precipitator exit stream is then recovered by the Wellman-Lord prescrubber. With a total ash feed of 111,362 lb/hr, only 80 lb/hr is emitted to the atmosphere; the remainder is recovered as bottom ash or by the flyash recovery systems. The recovered ash is quenched with water. Later, it is disposed of as 20% water and 80% ash sludge, which has a final settled density of 90 lb/ft^3.

The only other significant solid waste stream results from the Wellman-Lord sodium sulfite purge system. This system produces a dry crystalline mixture of sodium sulfate and sodium sulfite at a rate of 6,000 lb/hr. All solid and sludge wastes from the plant site are assumed to be disposed of near the site. Accumulation rates and land area requirements for disposal are summarized in Table 2-5 for the assumed plant capacity factor of 70%.

Table 2-5. Solid and Sludge Wastes - 1250 MWe Reference High-Sulfur Coal Generation - 70% Capacity Factor

Residual	Accumulation Rates at 70% Capacity Factor lb/hr	tons/yr	Acre-ft/year	30-year Land Area[a] (Acres)
Elemental Sulfur[b]	21,818	95,565	36	47
Ash Sludge[c]	97,372	426,490	218	283
Sodium Sulfite/ Sodium Sulfate	4,200	18,400	7	10
TOTAL				340

(a) Assumes 23 ft disposal typical of current practices.
(b) Disposal density = 122 lb/ft^3
(c) 80% ash, 20% water, density = 90 lb/ft^3. Solids content is 88,822 lb/hr from bottom ash, and 187 lb/hr from Wellman-Lord pretreatment.

4.4 LAND AND WATER USE

In addition to the waste disposal areas required to support the reference high-sulfur coal facility, an additional 500 acres is assumed for the primary plant site.[1, 2] This area includes an exclusion area of roughly 200 acres which is comparable to the requirements of a nuclear power plant. As shown previously in the plot arrangement (Figure B-1), the site also has sufficient provision for optional doubling of capacity through the construction of a second unit.

Consumptive water use occurs as a result of: (1) the cooling tower evaporative losses and blowdown, (2) general plant uses, and (3) process water from the Wellman-Lord SO_2 removal system. This system is the largest consumer of water. It requires 2 million gallons per hour for use in the venturi prescrubber and the absorber stage. Table 2-6 identifies various plant water uses.

Table 2-6. Water Use - 1250 MWe High-Sulfur Coal Generation

USE	10^6 GALLONS/DAY
Cooling Tower Evaporation	17
Cooling Tower Blowdown	5
Wellman-Lord SO_2 System	48
General Plant Use	<1
	70

Sources: Adapted from References 1, 2, 4.

The primary sources of liquid effluents from a conventional coal combustion facility include: (1) the boiler and cooling tower blowdown streams and (2) leachate from the ash handling and waste disposal areas. Actual levels of residuals that reach surface water systems vary considerably from site to site. These levels of residuals are highly dependent on drainage characteristics and waste disposal practices. Groundwater systems can also be affected either from percolation of rainwater through disposed wastes or from the movement of groundwater through the disposal area. Typical values of liquid effluents produced by the reference, high-sulfur coal facility operating at a 70% capacity are itemized in Table 2-7.

Table 2-7. Typical Wastewater Effluents--1250 MWe Coal Combustion Facility at 70% Capacity Factor

POLLUTANTS	TONS/DAY
BOD	0.101
COD	9.832
total suspended solids	0.024
total dissolved solids	62.607
aluminum	.022
chronium	.001
nonferrous metals	7.940
zinc	.004
sulfates	2.946
nickel	.259
nitrates	.130
ammonia	.004
phosphorous	.012

Source: Reference 15

5.0 CONSTRUCTION AND OPERATION CHARACTERISTICS

5.1 PERSONNEL REQUIREMENTS

Barring unusual regulatory delays, the normal construction period for a large, coal-fired electric generation facility (of the type characterized here) would take a total of 7 years. This includes a low level of effort period of 2 years for: (1) site selection, (2) design, and (3) preparation. In addition, a 5-year period is needed for actual on site construction. During the onsite construction period, an estimated 9.3 million man-hours of direct craft labor would be required. Table 2-8 details the 8 different labor types related to the above.

Table 2-8. Direct Labor Summary for Construction Craft Labor for 1250 MWe Coal Facility

CRAFT DESCRIPTION	SITE LABOR HOURS	PERCENT OF HOURS
Boiler Maker	232,700	2.5
Carpenter	409,500	4.4
Electrician	1,544,900	16.6
Iron Worker	967,900	10.4
Laborers	642,200	6.9
Millwrights	176,800	1.9
Operating Engineers	632,900	6.8
Pipefitters	2,475,500	26.6
Other Crafts	2,224,300	23.9
TOTAL Direct Construction	9,306,700	100.0

Sources: References 16, 17

The direct craft labor employment figures presented here do not include various inhouse utility and consultant man-hours. Both are considered indirect labor requirements by the utility for capital costing purposes. The magnitude of these indirect labor requirements, however, is somewhat less than the direct craft requirements.

Normal operation of the facility would require a plant staff of 259 persons and over 518,000 man-hours/year, which is shown in Table 2-9.[18]

Table 2-9. Direct Labor Summary for Construction and Operation of Reference 1250 MWe Coal Facility

OPERATIONAL PERSONNEL	NUMBER OF PERSONNEL	THOUSANDS MAN-HOURS PER YEAR
Plant Managers Office		
Manager	1	2
Assistant	1	2
Environmental Control	1	2
Public Relations	1	2
Training	1	2
Safety	1	2
Administrative Services	13	26
Health Services	1	2
Security	7	14
SUBTOTAL	27	54
Operations		
Supervision	3	6
Shifts	45	90
Fuel and Materials Handling	12	24
Waste Systems	15	30
SUBTOTAL	75	150
Maintenance		
Supervision	8	16
Crafts	95	190
Peak Maintenance Annualized*	35	70
SUBTOTAL	138	276
Technical and Engineering		
Waste	1	2
Radiochemical	2	4
Instrumentation and Control	2	4
Performance, Reports and Technicians	14	28
SUBTOTAL	19	38
TOTAL	259	518

* 300 persons for 6 weeks = 1,800 person weeks ÷ 52 weeks/yr = 35 persons annualized

Source: Reference 18

Occasionally, additional maintenance staff would be required to complete major scheduled or unscheduled emergency repairs on the turbine system, boiler, flue gas desulfurization system, or other major plant components.

5.2 OPERATING STATISTICS AND ANNUAL GENERATION

Historical statistics on large, coal-fired electric generation facilities of this type indicate that the overall plant capacity factor would be approximately 70%. (That is, the plant would produce 70% of the maximum possible kilowatt-hours it could generate if it were operated continuously at full capacity.).

Numerous parameters combine to produce this factor. Namely, these include: (1) plant down-time for scheduled maintenance, (2) plant forced outage rate due to unexpected component failure, and (3) the customer load profile (including inter-utility sales of electricity). The first two factors combine to determine plant availability, while the inclusion of customer demand results in the plant capacity factor.

Typically, a large coal-fired station (such as the type characterized here), would be placed early in the utility's loading order. Thus, it would hardly be affected by the customer's demand, since it would serve to satisfy part of the <u>minimum</u> customer load. However, a factor of .97 has been applied to the calculated plant availability to simulate a small reduction in plant operation because there is inadequate customer demand.

Scheduled maintenance for large coal facilities with flue gas desulfurization systems vary from 4 to 8 weeks per year, and forced outage rates range from 10 to 15%.[19,20] Here, the larger or more conservative values have been selected for the reference facility. Thus, plant availability is determined by:

$$\text{Plant Availability} = \frac{52-8}{52} \times (1-.15) \times 100\% = 72\%$$

Adjusting for customer demand reduction results in:

$$\text{Capacity Factor} = (72\%)\ (.97) = 70\%$$

At this capacity factor, reference 1250 MWe high-sulfur coal facility would generate 7.665×10^6 kilowatt-hours/year.

6.0 COST CHARACTERIZATION

The Energy Economic Data Base (EEDB) report prepared for DOE by United Engineers and Constructors details the base capital costs estimated for the 1250 MWe reference, high-sulfur coal generation facility. Direct and indirect capital costs presented in the EEDB are on a consistent January 1, 1978 dollar basis. They are the identical 1232 MWe United Engineers' plant design which provided the basis or starting point for the reference system characterization developed in the previous sections.[1, 2]

6.1 DIRECT CAPITAL COSTS

The EEDB costs have been appropriately adjusted to reflect major design changes and increased power levels incorporated into the 1250 MWe reference, high-sulfur coal system design. Specifically, the major design modifications that affect the reference system's capital cost (as compared to the 1232 MW United Engineers' design) include:

- A 5.9% increase in the boiler steam supply, steam generator, forced air and pulverizer air drafts, ash and dust, and fuel handling system capacities
- Replacement of the conventional lime SO_2 removal system processing only 88% of the flue gases with an advanced Wellman-Lord scrubber system to process 100% of the flue gas at a collection efficiency of 90% and elemental sulfur production from the process byproduct stream
- Installation of an in-stack steam-to-flue heat exchanger for reheating stack gas from 125°F to 175°F
- A 4.3% increase in the turbine generator gross output to compensate for additional auxiliary electrical loads not considered in the UEC design, and to provide for the increased net capacity
- A 1.8% reduction in the condenser and cooling tower heat rejection system

Base direct capital cost includes the costs of all materials, components, structures, and associated direct craft labor necessary to construct the reference facility at the plant site. Delivered costs for components, structures and materials are used. Base indirect costs include site temporary construction facilities, payroll insurance and taxes, and other construction services, such as home and field office expenses, field job supervision and engineering services. Specifically excluded from the base construction cost estimate are several items that are sensitive to the particular policies and preferences of the individual utility and to the specific plant site. Prevailing economic factors are being considered as follows:

- Owner's Costs - Consultants, Site Selection, etc.
- Federal, State and Local Fees, Permits, and Taxes
- Interest on Capital Construction Funds
- Price Escalation during Construction
- Contingency Funds
- Owner's Discretionary Items
    - Switchyard and Transmission Costs
    - Waste Disposal Costs
    - Spare Parts
    - Initial Fuel Supplies

We determined the 1250 MWe reference, high-sulfur coal system costs by reviewing the detailed cost estimates made in the EEDB for the 1232 MWe United Engineers' design at the "3-digit" subaccount level and then adjusting the costs.

The capacity-ratio exponent estimating technique was used to make incremental cost estimate modifications. The technique uses the following equation to adjust component costs for small to moderate change component capacity:

$$\text{Cost of Component B} = \text{Cost of Component A} \times \left(\frac{\text{Capacity of B}}{\text{Capacity of A}}\right)^{\alpha}$$

where component A and Component B are of similar design and performance, differing only in size or capacity, and where α is given by the following:

Account	Description	Cost Estimating Exponent (α)
20	Land and Land Rights	Not Applicable
21	Structures and Improvements	.20
22	Boiler Plant Equipment	.85
23	Turbine Plant Equipment	.70
24	Electric Plant Equipment	.20
25	Miscellaneous Plant Equipment	.40
26	Condenser Heat Rejection System	.50

The costs of two major components not originally included in the United Engineers' design were estimated by other means or by using other sources of data. The in-stack heat exchanger to reheat the flue gases exiting from the Wellman-Lord scrubber at 125°F to 175°F was estimated based on cost estimates of similar equipment using TVS's SHAWNEE computer code.[27] Equipment and materials costs for an in-stack heater capable of heating 5.6×10^6 lb/hr of flue gas from 125°F to 175°F have been estimated to be $1,035,600 in 1978 dollars. This cost was adjusted to the reference system design having a flue gas flow rate of 13.0×10^6 lb/hr by applying a 0.70* cost estimating exponent. Thus, equipment and materials costs for the reference system in-stack heater are estimated at $1,867,400. Craft labor requirements estimated from the TVA program were increased in proportion to the equipment and materials costs. This was an estimate of the labor requirements for the reference system in-stack heater. Craft labor requirements were thus estimated to be 5,640 man-hours.

The Wellman-Lord flue gas desulfurization system also differs substantially from the wet lime scrubber assumed in the United Engineers' design. For this system, costs were estimated from a recent Environmental Protection Agency (EPA) publication[4] which estimates the total capital investment (equipment, materials, labor, and working capital) for a 500 MW and a 1000 MW power plant burning 3.5% sulfur coal at $42.39 and $64.20 million, respectively. Costs of the Wellman-Lord system for the reference 1250 MWe facility (burning 3.2% sulfur coal) were estimated by removing 20% of the stated capital investment as working capital data to determine the equipment, materials, and labor costs for a 1250 MW installation. That is:

Capital Cost for EPA 500 MW Installation: $42.39M x 0.80 = $33.91M

Capital Cost for EPA 1000 MW Installation: $64.20M x 0.80 = $51.36M

$$\text{Implied Power Exponent} \quad \alpha = \frac{\ln\left(\frac{51.36}{33.91}\right)}{\ln\left(\frac{1000}{500}\right)} = 0.60$$

$$\text{Cost for 1250 MWe Installation} = \$51.36\text{M}\left(\frac{1250}{1000}\right)^{0.60} = \$58.72\text{M}$$

*The cost estimating exponent was assumed to be similar to that applicable to turbine plant equipment account which includes numerous heat exchangers.

This figure compares with an estimated cost of $55.68 million for the wet lime SO_2 removal equipment associated with the United Engineers' 1232 MWe design. Direct equipment and materials costs are estimated by assuming a direct labor requirement equal to that of the United Engineers' design for SO_2 equipment installation, or $19.80 million. Thus, the equipment and materials cost for the Wellman-Lord SO_2 removal system is estimated at $38.82 million.

Table 2-10 shows the original EEDB (United Engineers) cost estimate by "2-digit" accounts. Also shown are the applicable cost estimating factors and the resulting 1250 MWe reference system cost estimates for plant equipment and materials. Costs for land and land rights (Account 20) would not vary measurably over the capacity ranges considered here. Thus, the land costs shown assume a 500-acre site valued at $4,480 per acre. Land requirements for waste disposal are charged to operation and maintenance costs.

Direct craft labor costs for the 1232 MWe United Engineers facility are estimated from approximately 8,920,400 man-hours at a craft-averaged cost of $13.25 per man-hour. Labor costs for the reference system were estimated by first adding the labor requirements for installation of the in-stack heater to that of the United Engineers' facility. Man-hours and corresponding labor costs were then assumed to be proportional to the equipment and materials costs.(17) Resultant direct craft man-hours and costs are thus estimated to total 9,306,700 million man-hours and slightly more than $123.3 million.

Table 2-10. Estimated Direct Capital Costs for 1250 MWe Coal Combustion Reference System (January 1, 1978 Dollars)

Account	Description	1232 MWe EEDB[a] Cost ($1000)	CEM[b]	1250 MWe Reference System Cost ($1000)
20	Land & Land Rights[c]	2,240	1.000	2,240
21	Structures & Improvements	35,389	$1.043^{0.20}$	35,688
22	Boiler Plant Equipment			
	Total Except SO_2 Removal	99,690	$1.059^{0.85}$	104,668
	SO_2 Removal/Wellman-Lord	35,780	(d)	38,820
	In-Stack Heater	(e)	(e)	1,867
23	Turbine Plant Equipment	102,929	$1.043^{0.70}$	106,008
24	Electric Plant Equipment	20,202	$1.043^{0.20}$	20,373
25	Miscellaneous Plant Equipment	7,126	$1.043^{0.40}$	7,247
26	Condensate Heat Rejection System	11,961	$0.982^{0.50}$	11,853
	Total Direct Equipment & Materials Cost	315,317		328,764
	Site Labor Costs	118,157	(f)	123,314
	Total Direct Base Construction Costs	433,474		452,078

(a) EEDB, Energy Economic Data Base   Source: Adapted from Reference 21

(b) CEM = Cost Estimating Multiplier, see text for discussion

(c) Land and Land Rights for 500 acre main plant site at $4480/acre; waste disposal land allocated to operation and maintenance costs

(d) See text for discussion of cost estimating relationships for Reference System Wellman-Lord SO_2 Removal System

(e) Item not included in original EEDB design, see text for discussion

(f) Labor requirement for In-stack heater is added to EEDB estimate, then the total is escalated in proportion to Direct Equipment and Materials Costs

6.2 INDIRECT CAPITAL COSTS

Indirect capital costs associated with the construction of large coal combustion power plants are relatively insensitive to the plant capacities used in the EEDB and as the reference system described here. Thus, except for payroll related expenses, indirect capital costs for the 1250 MWe reference system have been taken to be the same as those for the EEDB 1232 MWe plant. Construction payroll related expenses include payroll insurance and taxes as well as field job supervision costs, which were assumed to be proportional to the reference system direct field labor costs. This assumption adds $839,000 to the Construction Services' account (#91) and $607,000 to the Field Office Engineering and Services' account (#93) over those costs estimated in the EEDB.

Indirect capital costs summarized in Table 2-11 at the "2-digit" account level, total $90,706,000, or about 20% of the direct capital cost estimated for the reference system.

Table 2-11. Estimated Indirect Capital Costs for 1250 MWe Coal Combustion Reference System (January 1, 1978 Dollars)

Account	Description	1250 MWe Reference System Cost ($1000)
91	Construction Services	55,469
92	Home Office Engineering and Services	18,790
93	Field Office Engineering and Services	16,447
	TOTAL INDIRECT	90,706

Source: Adapted from Reference 21

6.3 OPERATION AND MAINTENANCE COSTS

Annual operation and maintenance (O&M) costs for the 1250 MWe reference high-sulfur coal facility have been estimated. Based on cost estimating relationships in a recent Oak Ridge National Laboratory (ORNL) document entitled "A Procedure for Estimating Nonfuel Operation and Maintenance Costs for Large Steam Electric Power Plants,"[18] the data is available in the EEDB.[22] These cost estimating relationships were adjusted for characteristics unique to the reference design considered here and were supplemented with EPA data on Wellman-Lord flue gas desulfurization O&M costs.[23]

Generally, O&M costs may be considered to be composed of six cost categories. They may be either fixed costs (not dependent on annual generation) or variable costs which are proportional to generation level. The six cost categories considered here include: Plant Staffing, Maintenance Materials, Plant Supplies and Expenses, Environmental Controls, Interim Replacements, and Administrative and General Expenses.

Plant staffing costs are based on the 259-person plant staff described earlier and assumes a cost of $22,000 per person per year. Maintenance materials have been found to average 82% of the maintenance staff costs (138 persons) for large coal generation plants with flue gas desulfurization; 62% for fixed expenses and 20% representing a maximum level variable expense at a plant capacity factor of 80%. Fixed supplies and expenses have been estimated in the ORNL report to be $1.4 million/year with a variable component of 0.05 mills/kWh. Administrative, overhead, and utility home office general expenses associated with the reference facility are estimated by ORNL to be 10% of: (1) the staff costs, (2) the fixed components of the materials, and (3) the supplies costs.[18]

Operation and maintenance costs for environmental controls are based primarily on the ash, elemental sulfur, and dry sodium sulfite/sulfate disposal rates costed at $10/ton for ash sludge and $4/ton for the others, assuming remote site disposal. A disposal site land area of 11.3 acres/year at $4,480/acre has also been included in the estimated environmental controls O&M costs. Based on EPA data, feed materials, such as lime, sodium carbonate, catalyst, antioxidant and natural gas, are required for operation of the Wellman-Lord flue gas desulfurization system and the processing of its byproduct stream into elemental sulfur.

Annual costs for interim replacements of major capital items have been added to the O&M costs estimated by ORNL and in the EEDB. These were estimated to be 30% of the direct and indirect plant capital costs over its 30-year lifetime. A sinking fund annuity at 4% real interest was assumed to accrue 30% of the direct and indirect capital costs for interim replacements over the plant's lifetime. At this rate, 1.78% of 30% of the total plant capital costs (0.53% of total plant cost) is changed to O&M each year.

Table 2-12 details the annual O&M costs estimated for the reference high-sulfur coal system. At the 70% capacity factor assumed for the reference coal system, annual O&M costs total \$23.5 million or 3.06 mills/kWh; 1.66 mills/kWh are fixed costs while 1.40 mills/kWh are variable with plant load factor.

These O&M costs compare to an estimated 3.4 mills/kWh for an identical system using wet limestone scrubbers. The difference, 0.34 million per year, is a result of reduced disposal costs and disposal site land requirements achievable with the advanced Wellman-Lord sulfur removal system and SO_2 to elemental sulfur production.

Several of the foregoing cost estimating relationships are considered high. For example, interim replacements totaling 30% of the plant's direct and indirect costs is about two to three times that which would be expected for a facility of this type.[24, 25] Also, if it were assumed that the elemental sulfur were marketed at its long term equilibrium market price of \$50/ton,[26] sulfur disposal handling costs of \$382,000/year, and associated land costs of \$7500/year would be avoided. A credit of \$4,778,250/year would be received. These modifications would reduce the reference plant's annual O&M cost to \$18,297,250/year of 3.29 mills/kWh, a 22% reduction from the O&M cost used here.

Table 2-12. Annual Operation and Maintenance Costs for 1250 MWe Reference High-Sulfur Coal Facility at 70% Capacity Factor

O&M Cost Account	Cost Estimating Relationship	$1000/yr
Plant Staff	259 persons @ $22,000/yr (Fixed Cost)	5,700
Maintenance Materials	Fixed: 138 persons x 22,000 $/yr x .62	1,882
	Variable: 138 persons x 22,000 $/yr x .20 x (.70/.80)	531
Supplies & Expenses	Fixed:	1,400
	Variable: $\frac{(.05 \text{ mills/kWh})(1{,}250{,}000 \text{ kW})(8760 \text{ hr/yr})(.7)}{1{,}000 \text{ mills/\$}}$	385
Environmental Control	Fixed: Included in Maintenance Materials, Supplies and Expenses	--
	Variable:	
	Ash disposal: 426,490 T/yr @ 10 $/T	4,265
	Sulfur disposal: 95,565 T/yr @ 4 $/T	382
	Sodium Sulfite/ Sulfate disposal: 18,396 T/yr @ 4 $/T	74
	Disposal Site: 11.3 acres/yr @ 4480 $/acre	51
	Wellman-Lord Feed Materials*	
	Lime: 257 T/yr @ 42 $/T	11
	Sodium Carbonate: 17,920 T/yr @ 78 $/T	1,398
	Catalyst (proprietary)	23
	Antioxidant: 304 T/yr @ 5500 $/T	1,672
	Natural Gas: 967 x 10^6 ft^3 @ $2/$10^3$cf	1,934
Interim Replacements	Sinking fund accrual of 30% of direct & indirect plant capital costs @ 30 years and 4% interest (Fixed Cost)	2,859
Administrative & General	10% of Staff, Fixed Materials & Fixed Supplies & Expenses (Fixed Cost)	898
TOTAL ANNUAL O&M COSTS		23,465

At 70% Capacity Factor:

Fixed O&M Costs: $\frac{(12{,}739{,}000 \text{ \$/yr})(1000 \text{ mills/\$})}{(1{,}250{,}000 \text{ kW})(8760 \text{ hr/yr})(.7)}$ = 1.66 mills/kWh

Variable O&M Costs: $\frac{(10{,}726{,}000 \text{ \$/yr})(1000 \text{ mills/\$})}{(1{,}250{,}000 \text{ kW})(8760 \text{ hr/yr})(.7)}$ = 1.40 mills/kWh

TOTAL O&M COSTS 3.06 mills/kWh

*Based on EPA data, Reference 4

Sources: Refs. 4, 18, 22, 23

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SECTION 3. LIGHT WATER REACTOR WITH IMPROVED FUEL UTILIZATION

3. LIGHT WATER REACTOR WITH IMPROVED FUEL UTILIZATION

1.0 INTRODUCTION

The 1250 MWe light water reactor (LWR) facility characterization provided in this section was written and based primarily on "Satellite Power System and Alternate Technology Characterization" prepared by United Engineers and Constructors, Inc., August 1979, UEC-ANL-790831. The cost data also provided in this characterization is based on NUREG-0241, "Capital Cost: Pressurized Water Reactor Plant," prepared by United Engineers and Constructors, Inc. In both cases, the reactor plant itself is based on the Westinghouse 3425 MWe reactor described in RESAR-35, and an inland nuclear site (Middletown), and a UEC balance of plant design with mechanical draft cooling towers.

The description in this report is structured with the purpose of comparing one technology with another, both projected to the year 2000. In this respect, the technologies had to be made comparable with regard to electrical energy generation: 1250 MWe was chosen as being representative of large bulk power generation facilities in the year 2000. The basic Westinghouse 3450 MWt reactor plant was scaled up to 3800 MWt. The cost estimate is based on this plant as well as major equipment. While scaling does provide a valid general representation of the 1250 MWe plant, a more representative or meaningful characterization would have been obtained if the Westinghouse 3800 MWt unit (described in Resar-41) were used.

Fuel utilization in a nuclear plant is the subject of current RD&D programs. The basic goal of these programs is to increase the burnup of the fuel and decrease the U-235 requirement on a per-unit-of-power generation basis. At the present time, nuclear fuel is being discharged from reactors after achieving an average burnup of 25,000 to 33,000 megawatt days per metric tonne of fuel (MWD/MT). New fuel designs are being tested at commercial nuclear facilities in the hopes of ultimately achieving a 50,000 MWD/MT burnup. For the purpose of this characterization, a maximum 50,000 MWD/MT [8] burnup is assumed for the LWR in the year 2000.

A 1250 MWe nuclear reactor is loaded with approximately 98 metric tonnes (MT) of fuel at beginning of life and will consume about 20 MT each refueling.

Over the past 10 years, the basic designs of the nuclear facilities have changed dramatically. Size of the units has increased to about 1250 MWe (3800 MWt) and extensive safety systems have been incorporated. Between now and the year 2000, size is assumed not to increase beyond present standards because of safety concerns by the NRC. However, safety will continue to be a major driving force in the design modifications of nuclear facilities. Investigations of the Three Mile Island accident will produce design changes for safety reasons in the near-term. Through the year 2000, the continued striving for a "perfectly safe" form of nuclear energy will result in numerous design changes required by the regulatory agencies to enhance safety.

Pollution control equipment will continue to be required for power generation facilities. For a nuclear plant, better radiological control equipment will be developed and installed to minimize or eliminate entirely hazardous radionuclide emissions, In addition, pollutant abatement regulations are assumed to require no process stream discharges containing any pollutants. The only assumed exception to this basic assumption is the cooling tower blowdown. However, degradable biocides and corrosion inhibitors are assumed to be used in the cooling towers. Ice prevention is accomplished through temperature control.

The fuel cycle assumed for the LWR characterization is the once through, throw away fuel cycle. Spent fuel disposal is accomplished by the Federal Government in Federally owned disposal facilities (a geologic repository is assumed). Costs for spent fuel disposal are recovered by the Government through a charge levied on the user of the waste disposal facilities. Reprocessing is not allowed.

2.0 GENERAL PLANT CONFIGURATION

The reference LWR described in this section is a single-unit pressurized water reactor of Westinghouse Electric Company design with a net plant capacity of 1250 MWe. The basic nuclear plant is modeled after the Westinghouse 3425 MWt unit as described in RESAR-35 and coupled to a balance-of-plant concept designed by United Engineers and Constructors (UEC) as described in their reports "Commercial Electric Power Cost Studies," and "Satellite Power System and Alternative Technology Characterization." The primary features of the UEC design are the Nuclear Steam Supply System (NSSS), the six flow tandem compound turbine generator with supporting power conversion cycle equipment and systems, and the station cooling system using three mechanical draft wet-cooling towers.

The overall design of the unit was based on the licensing, design, construction, and operation criteria, standards, codes, and guidelines in effect about January 1 1976. The characterization represents the current state of technology in the late 1970's but projected to the year 2000. It must be realized that between the time the reference plant was designed and the year 2000, numerous changes will be made in the design requirements of the LWR levied by the various regulatory agencies. These design requirement changes will be derived from the lessons learned at Three Mile Island, some of which are known and can be quantified. However, many more design changes will be required through the year 2000 which cannot be quantified nor anticipated at this time. Caution must be exercised then in the use of this design projected to the year 2000.

Figure 3-1 shows the basic plot plant for a single 1250 MWe LWR facility. The predominant features include the containment structure, switchyard, three mechanical draft cooling towers, and the turbine building. The layout also includes provision for the addition of a second unit at some future date. Space requirements for these additional facilities are shown by the broken lines on Figure 3-1.

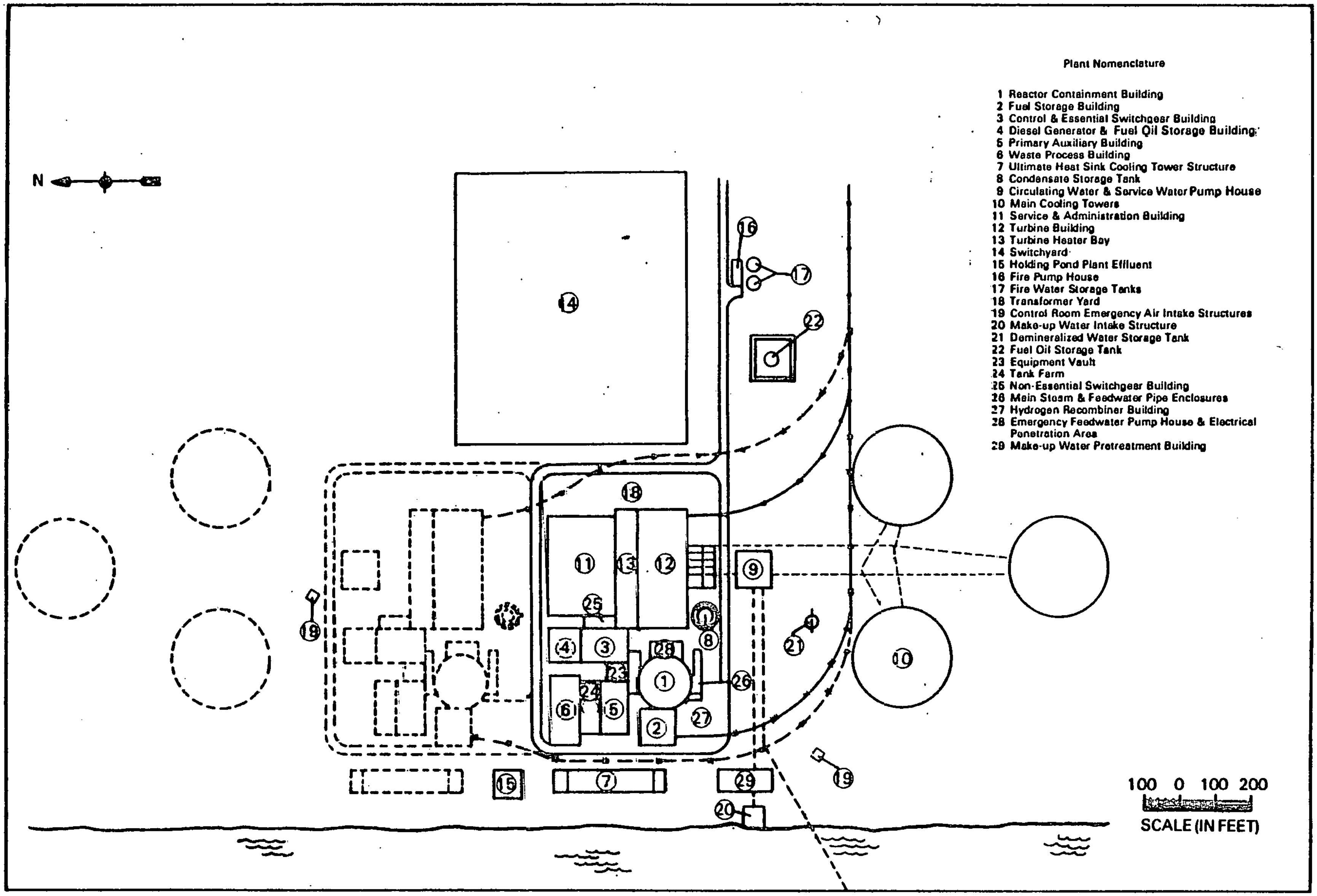

Figure 3-1. Plot Plan 1250 MWe LWR Facility

One of the more striking features of the nuclear reactor power station is the reactor containment building, a leak-tight reinforced concrete cylindrical structure with a hemispherical dome based on a flat reinforced concrete foundation mat. The cylindrical portion of the building is approximately 140 ft in diameter and the dome has an inside spherical radius of 70 ft. The inside height, from the foundation mat to the top of the dome, is 219 ft and the minimum thickness of the dome structure is 2.5 ft. The turbine and generating equipment are housed in a separate building immediately adjacent to the reactor containment building. A primary auxiliary building having structural requirements similar to the reactor containment adjoins the reactor containment building. The building contains (in addition to the primary component cooling systems) most of the engineered safety features designed to protect the reactor core. This includes the low-pressure injection system, the containment core spray and emergency core cooling systems. A waste processing building houses liquid and gas waste-processing (as well as other systems which may have any radioactivity associated with them). The control systems for the entire station are located in a separate control building. The building has structural requirements similar to that of the main containment. The electrical generating portion of the plant is similar to that associated with fossil fuels systems. It consists of the turbine and the generator connected with it, the main condenser, and the associated feedwater equipment.

The balance of the reactor plant systems includes the boron recycle system, radwaste system, service waste systems, containment spray, combustible gas controls, fuel handling, fuel storage, reactor makeup water system, the primary component cooling water system, and the air cleanup system. The balance of the conventional portion of the plant includes the usual transformer, switchgear and switchyard components, and the connection to the distribution lines. The main condenser heat rejection system includes makeup water intake and discharge structures, circulating water pumphouse, makeup water pretreatment facilities, and three mechanical draft wet-cooling towers.

3.0 THERMODYNAMIC CYCLE CHARACTERISTICS[1]

The NSSS consists of a light-water-moderated nuclear reactor having a reactor core containing low enriched uranium oxide fuel, approximately 4.0% U-235, in approximately 193 fuel assemblies. The core is refueled by replacing approximately one-third of the total set of fuel elements at roughly one year intervals. The spent fuel is stored onsite in a special fuel handling building. This building is also a repository for fresh fuel prior to its insertion in the core.

The NSSS produces approximately 3760 MWt at nominal full power. The power generation system consists of the reactor core and vessel, its associated pressurizer, and four primary reactor coolant loops and four steam generators. Primary coolant (water) is heated by the nuclear reaction taking place in the core. This hot water is then passed through the steam generators (u-tube heat exchangers) where water on the secondary side of the heat exchanger is heated to produce steam. Water on the primary side of the steam generator is returned to the core to be reheated. Steam produced on the secondary side of the steam generator passes through the turbine generator power conversion system. The turbine generators, at nominal rated power, produce 1250 MWe. The condensate from the turbine is returned by the steam generator feedwater pumps. The reactor is equipped with residual heat removal systems and a number of engineered safeguards to permit shutdown and heat removal under all credible accident conditions.

3.1 REACTOR CORE AND VESSEL

The reactor core is composed of the fuel assemblies containing the fissionable uranium dioxide material contained in Zircaloy-4 tubes. The tubes are bundled together forming fuel assemblies which are in turn placed together inside the reactor vessel (cylindrical in shape) to form the core. Pressurized primary coolant (water with boric acid added for reactor control) is circulated up through the core and heated by the nuclear reaction.

Control rods and acid in the primary coolant provide control of the nuclear reaction. The control rods and boric acid absorbs neutrons produced by the reaction and necessary for its maintenance. The control rods are used primarily for rapid reactor control (power changes, reactor rapid shutdowns, etc.) while the boric acid is used primarily to control slow changes in the reactor (fuel depletion and Xenor transients). Table 3-1 shows the various characteristics of the reactor core and fuel.

Table 3-1. Key Parameters, Nuclear Steam Supply System
1250 MWe Pressurized Water Reactor Plant

Parameters	Operating Description
NSSS Warranted Power, MWt	3,750
Steam Flow, 10^6 lb/hr	16.62
Steam Pressure, psia	1,100
Power Density - Avg., kW/liter	104
Linear Power - Avg., kW/ft	5.4
Linear Power - Max., kW/ft	12.6
Heat Flux - Avg., Btu/hr/ft^2	189,800
Heat Flux - Max., Btu/hr/ft^2	474,500
Min. Crit. Heat Flux Ratio	1.3
Number of Fuel Assemblies	193
Number of Control Assemblies	65
Reactor Vessel ID, in	173
Number of Coolant/Recirculation Loops	4
Pump Capacity, gpm	103,635
Coolant Flow, 10^6 lb/hr	165.2
Coolant Inlet Temp. ^oF	563.8
Avg. Delta T through Vessel	61.1
Coolant Pressure - Outlet, psia	2,250
Steam Generator Size - Height,, ft-in	67-8
- Dia., ft-in	14-8

3.2 REACTOR PLANT EQUIPMENT

The reactor plant design incorporates four parallel primary loops circulating reactor coolant through the reactor core and the four steam generators. Four primary coolant pumps each circulate the coolant through the reactor and steam generators at an average flow rate of 165.4×10^6 lb/hr, with a reactor inlet temperature of 563.8°F and an average temperature rise of 61.1°F. The nominal coolant pressure is 2250 psia. The high pressure is maintained in the primary system by a pressurizer to prevent boiling in the core.

The steam generation system consists of four water-to-water/steam once-through steam generators (one for each of the primary coolant loops). The steam generators are the vertical shell and U-tube evaporator type with integral moisture separation equipment. The reactor coolant is on the tube side. Steam is produced at 1100 psia and 556.3°F. The feedwater temperature is 440°F. The total steam design flow rate is 16.62×10^6 lb/hr.

In addition to the primary heat transfer tystems, the reactor operation is supported by a wide variety of supporting systems including the safety systems used to mitigate the consequences of reactor accidents, radioactive waste processing and handling systems, and various chemical makeup and sampling systems.

3.3 TURBINE GENERATOR CONFIGURATION

The turbine configuration is a tandem compound, six flow machine with 43 inch last stage blades, designed and operated at 1800 rpm. Inlet steam conditions at the HP throttle valves are 975 psia and 544°F. No superheat is provided by this reactor plant design so the inlet steam is at saturation.

The generator is rated at 1482 MVA at a 0.9 PF. The generator output is 25,000 V, 3 phase, 60 Hz and delivers 1309 MWe gross.

The steam flow configuration through the turbines begins with high pressure steam entering the high pressure turbine. As the steam passes through the HP and LP turbines and expands, the steam imparts about 1.37×10^{10} Btu/hr (1,329,985 kW) to the turbine shaft. Table 3-2 shows key plant parameters.

Table 3-2. Key Plant Parameters, Steam and Power Conversion System 1250 MWe Pressurized Water Reactor Plant

Parameter	Operating Description
Turbine Output, MWe	1,309
Auxiliary Power, MWe	59
Net Power to Transformer, MWe	1,250
Generator Rating, MVA	1,482
Net Station Steam Rate, lb/kWh	13.3
Net Station Heat Rate, Btu/kWh	10,224
Plant Efficiency %	33.4
Main Steam Flow at HP Turbine Inlet, lb/hr	16,621,439
Main Steam Pressure at HP Turbine Inlet, psia	975
Main Steam Temperature at HP Turbine Inlet, °F	544

3.4 CONDENSER-HEAT REJECTION SYSTEM

Three equalized single stage, two pass-surface condensers, with divided fabricated steel water boxes and shell, are provided. The condensers are designed to condense the low press turbine outlet steam and feedwater pump auxiliary turbine drive exhaust steam at 3.75 in Hga by dissipating the heat to three mechanical draft wet-cooling towers. Each condenser contains about 328,000 sq. ft. of condensing surface made up of 19,910 1-1/8 inch diameter, 20 BWG 90-10 CuNi tubes.

The three main mechanical draft wet-cooling towers are each sized for one-third of the requirements. Each tower is designed to cool 215,000 gpm of water from 118°F to 92°F when operating at a wet bulb temperature of 70°F. Each tower employs a reinforced concrete-filled structure combined with components for water distribution, fill splash service, support system, drift eliminators, louvers, and fan deck. The fan deck provides a stable base for the 12 fan cylinders and mechanical equipment. Each fan is 33 ft in diameter and operates in an 18 ft high glass reinforced polyester velocity recovery fan stack. The hot water distribution system includes a circular flume distribution basin and metering orifice which uniformly distributes the hot water over the fill.

3.5 FEEDWATER HEATERS

Feedwater flow from the condenser enters a series of six series reverse cascade feedwater heaters designed to achieve a final feedwater temperature of 440° F at 16.62×10^6 lb/hr. The first five stage heaters are low pressure. The final stage is designed for full steam generator pressure. Steam for the feedwater heaters is provided from the moisture separator and various extraction points throughout the steam cycle, and from other residual steam flows. A total of 6.07×10^9 Btu/hr. is added to the feedwater before entering the boiler as shown in Figure 3-2. Small amounts of energy are contributed by the condensate and feed pumps primarily from pump thermal losses.

3.6 GENERATOR LOSSES AND AUXILIARY ELECTRIC ENERGY USE

The total power delivered to the turbine shaft is about 1,329,985 kW. Various generator inefficiencies result in the loss of 21,147 kW or 1.60 % of the shaft power as fixed and generation losses. Approximately 58,785 kW is required to support the plant operation (as shown in Table 3-3). This results in a net output of 1,240,053 kW.

Table 3-3. Auxiliary Power Requirements

Component	Load in Kilowatts (kW)
Main Coolant Pumps	22,920
Condensate Pumps	2,045
Heater Drain Pumps	2,045
Condensate Booster Pumps	4,095
Service Water Pumps	820
Cooling Tower Fans	4,425
Make-up Water Pumps	210
Circulating Water Pumps	16,350
TOTAL	52,910
Miscellaneous Small Pumps, Fans, Heaters	3,295
"Hotel" Load	2,580
TOTAL	58,785

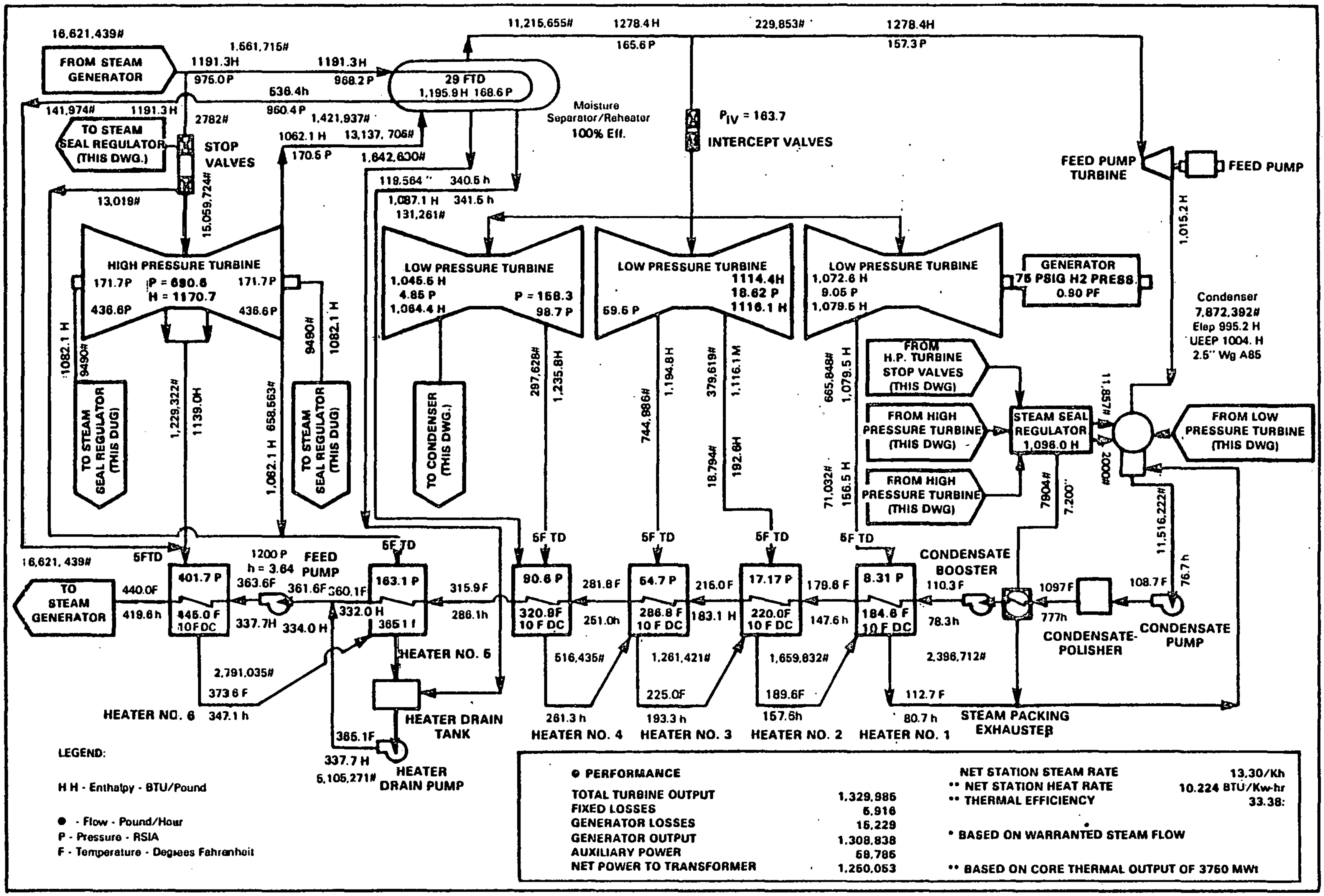

Figure 3-2. Light Water Reactor Facility Heat Balance

3.7 FUEL USE AND LOGISTICS

The reference LWR facility uses 4.15% enriched uranium.[8] The Department of Energy provides enrichment services to the utility industry producing uranium hexafloride containing 4.15% U-235. The UF_6 is then converted to UO_2 and fabricated into fuel assemblies for use in the reactor. For the reference 1250 MWe net LWR, approximately 98,000 kg of fuel are loaded into the reactor.

The fuel is discharged from the reactor after it has achieved an average burnup of 50,000 MWD/MT.[8] After discharge, it is placed in the spent fuel pool for temporary storage. During this temporary storage, the residual decay heat produced by fission product decay is removed by the fuel pool cooling system. Storage in this spent fuel pool could last for from one to five years at which time the spent fuel is shipped offsite to government owned and operated disposal facilities. The storage time on site will depend on waste acceptance criteria at the AFR or the repository.

The reactor does not discharge all of its fuel during refueling. Only about 1/5 of the assemblies are replaced during each refueling, while the other 4/5 are moved to different positions in the core. Refueling would take place about every 12 months at a 70% capacity factor. New fuel is shipped to the site and stored dry.

4.0 ENVIRONMENTAL CHARACTERISTICS

Numerous reactor plant systems, even under normal conditions, become contaminated with radioactive elements. These elements can come from the fuel itself or from: (1) impurities in the fuel cladding, (2) activated wear products, or (3) other sources. Because several systems are contaminated, normal maintenance, operations, and leaks will lead to release of some of these elements.

The transport mechanisms for release of these radioactive elements are primarily through the building ventilation systems and processed liquid effluents. Areas which have the potential for contamination are ventilated through high efficiency particulate filters. These filters remove greater than 99.9 percent of the particles in the air which are larger than 0.3 microns. Potentially contaminated liquid effluents are monitored or processed to remove radioactive elements by filtration and ion exchange. In each case, not all of the radioactive elements can be prevented from entering the biosphere. Consequently, radioactive elements are emitted to the biosphere by the LWR. Tables 3-4 and 3-5 list the expected annual average radionuclide releases from the reference LWR. Additional releases resulting from other parts of the fuel cycle are discussed in the following section on the nuclear fuel cycle.

4.1 SOLID WASTE

Normal maintenance and operation of an LWR results in the generation of on-site solid and liquid wastes. Clothing, rags, laboratory equipment, monitoring equipment, tools, filters, etc., all can become contaminated and, if decontamination is not possible, should be discarded. Table 3-6 shows the average annual shipments of on-site generated waste. These wastes are categorized as low-level wastes and are suitable for disposal in licensed commercial low-level waste burial grounds.

Uncontaminated solid waste and refuse is also generated at the plant site and disposed of by conventional landfill offsite.

Table 3-4. Expected Annual Average Release of Airborne Radionuclides

ISOTOPE	PRIMARY COOLANT (μCi/g)	SECONDARY COOLANT (μCi/g)	GASEOUS RELEASE RATE (Ci/yr)							
			GAS STRIPPING		BUILDING VENTILATION			BLOWDOWN	AIR EJECTOR	
			SHUTDOWN	CONTINUOUS	REACTOR	AUXILIARY	TURBINE	VENT OFFGAS	EXHAUST	TOTAL
Kr-83m	2.163×10^{-2}	5.973×10^{-9}	0.0[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kr-85m	1.131×10^{-1}	3.187×10^{-8}	0.0	0.0	0.0	3.2×10^{0}	0.0	0.0	2.1×10^{0}	5.3×10^{0}
Kr-85	1.009×10^{-1}	2.811×10^{-8}	5.7×10^{1}	6.1×10^{2}	7.8×10^{1}	2.1×10^{0}	0.0	0.0	1.1×10^{0}	7.5×10^{2}
Kr-87	8.092×10^{-2}	1.648×10^{-8}	0.0	0.0	0.0	1.1×10^{0}	0.0	0.0	0.0	1.1×10^{0}
Kr-88	2.061×10^{-1}	5.661×10^{-8}	0.0	0.0	0.0	5.3×10^{0}	0.0	0.0	3.2×10^{0}	8.5×10^{0}
Kr-89	5.156×10^{-3}	1.444×10^{-9}	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Xe-131m	9.88×10^{-2}	2.786×10^{-8}	4.3×10^{0}	1.5×10^{1}	1.8×10^{1}	2.1×10^{0}	0.0	0.0	1.1×10^{0}	4.2×10^{1}
Xe-133m	2.190×10^{-1}	6.170×10^{-8}	0.0	0.0	7.4×10^{0}	5.3×10^{0}	0.0	0.0	3.2×10^{0}	1.6×10^{1}
Xe-133	1.723×10^{1}	4.784×10^{-6}	2.5×10^{1}	5.0×10^{1}	1.3×10^{3}	4.0×10^{2}	0.0	0.0	2.6×10^{2}	2.1×10^{3}
Xe-135m	1.341×10^{-2}	3.712×10^{-9}	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Xe-135	3.586×10^{-1}	0.994×10^{-7}	0.0	0.0	2.1×10^{0}	8.5×10^{0}	0.0	0.0	5.3×10^{0}	1.6×10^{1}
Xe-137	9.281×10^{-3}	2.578×10^{-9}	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Xe-138	4.537×10^{-2}	1.238×10^{-8}	0.0	0.0	0.0	1.1×10^{0}	0.0	0.0	0.0	1.1×10^{0}
TOTAL NOBLE GASES										3.0×10^{3}
I-131	2.669×10^{-1}	6.834×10^{-5}	0.0	0.0	1.8×10^{-3}	4.7×10^{-2}	4.1×10^{-3}	0.0	3.0×10^{-3}	5.5×10^{-2}
I-133	3.806×10^{-1}	5.066×10^{-5}	0.0	0.0	8.2×10^{-4}	6.7×10^{-2}	3.1×10^{-3}	0.0	4.3×10^{-3}	7.6×10^{-2}
TRITIUM GASEOUS RELEASE			1114 Ci/yr							

[a]The figure 0.0 appearing in the table indicates that the release is less than 1.0 Ci/yr for noble gas, 0.0001 Ci/yr for I.

Table 3-4. Expected Annual Average Release of Airborne Radionuclides (Cont'd)

NUCLIDE	AIRBORNE PARTICULATE RELEASE RATE (Ci/yr)			
	WASTE GAS SYSTEM	BUILDING VENTILATION		TOTAL
		REACTOR	AUXILIARY	
Mn-54	4.8×10^{-3}	6.5×10^{-6}	1.9×10^{-4}	5.0×10^{-3}
Fe-59	1.6×10^{-3}	2.3×10^{-6}	6.4×10^{-5}	1.7×10^{-3}
Co-58	1.6×10^{-2}	2.3×10^{-5}	6.4×10^{-4}	1.7×10^{-2}
Co-60	7.5×10^{-3}	2.3×10^{-5}	6.4×10^{-4}	7.7×10^{-3}
Sr-89	3.5×10^{-4}	5.0×10^{-7}	1.3×10^{-5}	3.6×10^{-4}
Sr-90	6.4×10^{-5}	9.0×10^{-8}	2.6×10^{-6}	6.7×10^{-5}
Cs-134	4.8×10^{-3}	6.5×10^{-6}	1.9×10^{-4}	5.0×10^{-3}
Cs-137	8.0×10^{-3}	1.1×10^{-5}	3.2×10^{-4}	8.3×10^{-3}

Note: In addition to these releases, 28 Ci/yr of argon-41 are released from the containment and 9 Ci/yr of carbon-14 are released from the waste gas processing system.

Table 3-5. Expected Annual Average Releases of Radionuclides in Liquid Effluents

CORROSION AND ACTIVATION PRODUCTS	NUCLIDE HALF-LIFE (days)	COOLANT CONCENTRATIONS		ANNUAL RELEASES TO DISCHARGE CANAL					ADJUSTED TOTAL (ci/yr)	DETERGENT WASTES (Ci/yr)	TOTAL (Ci/yr)
		PRIMARY (μCi/ml)	SECONDARY (μCi/ml	BORON RECOVERY SYSTEM (curies)	MISCEL-LANEOUS WASTES (curies)	SECONDARY (curies)	TURBINE BUILDING (curies)	TOTAL LIQUID WASTE (curies)			
Cr-51	$2.78x10^{1}$	$1.90x10^{-3}$	$4.40x10^{-7}$	$5.71x10^{-6}$	$1.57x10^{-7}$	0.0	$4.63x10^{6}$	$10.50x10^{6}$	$6.96x10^{-5}$	0.0	$6.9x10^{-5}$
Mn-54	$3.03x10^{2}$	$3.10x10^{-4}$	$1.08x10^{-7}$	$9.82x10^{-7}$	$2.64x10^{-8}$	0.0	$1.14x10^{-6}$	$2.15x10^{-6}$	$1.42x10^{-5}$	$1.06x10^{-3}$	$1.1x10^{-3}$
Fe-55	$9.50x10^{2}$	$1.60x10^{-3}$	$3.77x10^{-7}$	$5.09x10^{-6}$	$1.37x10^{-7}$	0.0	$3.99x10^{-6}$	$9.22x10^{-6}$	$6.10x10^{-5}$	0.0	$6.1x10^{-5}$
Fe-59	$4.50x10^{1}$	$1.00x10^{-3}$	$2.73x10^{-7}$	$3.07x10^{-6}$	$8.36x10^{-8}$	0.0	$2.87x10^{-6}$	$6.04x10^{-6}$	$4.00x10^{-5}$	0.0	$4.0x10^{-5}$
Co-58	$7.13x10^{1}$	$1.60x10^{-2}$	$3.80x10^{-6}$	$4.98x10^{-5}$	$1.35x10^{-6}$	0.0	$4.01x10^{-5}$	$9.13x10^{-5}$	$6.05x10^{-4}$	$4.26x10^{-3}$	$4.9x10^{-3}$
Co-60	$1.92x10^{3}$	$2.00x10^{-3}$	$4.84x10^{-7}$	$6.36x10^{-6}$	$1.70x10^{-7}$	0.0	$5.13x10^{-6}$	$1.18x10^{-5}$	$7.73x10^{-5}$	$9.25x10^{-3}$	$9.4x10^{-3}$
Np-239	$2.35x10^{0}$	$1.20x10^{-3}$	$1.94x10^{-7}$	$1.95x10^{-6}$	$7.04x10^{-8}$	0.0	$1.90x10^{-6}$	$3.92x10^{-6}$	$2.60x10^{-5}$	0.0	$2.6x10^{-5}$
FISSION PRODUCTS											
Br-83	$1.00x10^{-1}$	$4.80x10^{-3}$	$1.37x10^{-7}$	$8.87x10^{-9}$	$9.04x10^{-8}$	0.0	$2.59x10^{-6}$	$2.69x10^{-6}$	$1.78x10^{-5}$	0.0	$1.8x10^{-5}$
Rb-86	$1.87x10^{1}$	$8.50x10^{-5}$	$2.43x10^{-8}$	$6.24x10^{-6}$	$3.45x10^{-7}$	0.0	$2.55x10^{-7}$	$6.83x10^{-6}$	$4.54x10^{-5}$	0.0	$4.6x10^{-5}$
Sr-89	$5.20x10^{1}$	$3.50x10^{-4}$	$1.09x10^{-7}$	$1.09x10^{-6}$	$2.92x10^{-8}$	0.0	$1.15x10^{-6}$	$2.25x10^{-6}$	$1.50x10^{-5}$	0.0	$1.5x10^{-5}$
Mo-90	$2.79x10^{0}$	$8.40x10^{-2}$	$1.90x10^{-5}$	$1.51x10^{-4}$	$5.21x10^{-6}$	0.0	$1.89x10^{-4}$	$3.46x10^{-4}$	$2.29x10^{-3}$	0.0	$2.4x10^{-3}$
Tc-99m	$2.50x10^{-1}$	$4.80x10^{-2}$	$2.58x10^{-5}$	$1.45x10^{-4}$	$4.72x10^{-6}$	0.0	$2.21x10^{-3}$	$3.71x10^{-4}$	$2.45x10^{-3}$	0.0	$2.5x10^{-3}$
Te-127	$3.92x10^{-1}$	$8.50x10^{-4}$	$1.65x10^{-7}$	$9.02x10^{-7}$	$3.24x10^{-8}$	0.0	$1.30x10^{-6}$	$2.23x10^{-6}$	$1.48x10^{-5}$	0.0	$1.5x10^{-5}$
Te-129m	$3.40x10^{1}$	$1.40x10^{-3}$	$3.29x10^{-7}$	$4.26x10^{-6}$	$1.16x10^{-7}$	0.0	$3.47x10^{-6}$	$7.83x10^{-6}$	$5.19x10^{-5}$	0.0	$5.3x10^{-5}$
Te-129	$4.79x10^{-2}$	$1.60x10^{-3}$	$5.63x10^{-7}$	$2.72x10^{-6}$	$7.49x10^{-8}$	0.0	$2.32x10^{-6}$	$5.12x10^{-6}$	$3.39x10^{-5}$	0.0	$3.4x10^{-5}$
I-130	$5.17x10^{-1}$	$2.10x10^{-3}$	$1.99x10^{-7}$	$3.17x10^{-6}$	$4.46x10^{-7}$	0.0	$1.51x10^{-5}$	$1.87x10^{-5}$	$1.15x10^{-4}$	0.0	$1.2x10^{-4}$
Te-131m	$1.25x10^{0}$	$2.50x10^{-3}$	$3.52x10^{-7}$	$2.23x10^{-6}$	$1.10x10^{-7}$	0.0	$3.25x10^{-6}$	$5.60x10^{-6}$	$3.71x10^{-5}$	0.0	$3.7x10^{-5}$
I-131	$8.05x10^{0}$	$2.70x10^{-1}$	$6.34x10^{-5}$	$7.06x10^{-3}$	$2.06x10^{-4}$	0.0	$6.57x10^{-3}$	$1.36x10^{-2}$	$9.17x10^{-2}$	$6.60x10^{-5}$	$9.2x10^{-2}$
Te-132	$3.25x10^{0}$	$2.70x10^{-2}$	$4.98x10^{-6}$	$5.26x10^{-5}$	$1.76x10^{-6}$	0.0	$5.00x10^{-5}$	$10.95x10^{-5}$	$6.92x10^{-4}$	0.0	$6.9x10^{-4}$
I-132	$9.58x10^{-2}$	$1.00x10^{-1}$	$1.01x10^{-5}$	$5.50x10^{-5}$	$9.04x10^{-6}$	0.0	$2.18x10^{-4}$	$2.82x10^{-4}$	$1.87x10^{-3}$	0.0	$1.9x10^{-3}$
I-133	$8.75x10^{-1}$	$3.80x10^{-1}$	$4.82x10^{-5}$	$1.98x10^{-3}$	$1.31x10^{-4}$	0.0	$4.18x10^{-3}$	$6.30x10^{-3}$	$4.17x10^{-2}$	0.0	$4.1x10^{-2}$
Cs-134	$7.49x10^{2}$	$2.50x10^{-2}$	$7.11x10^{-6}$	$1.99x10^{-3}$	$1.06x10^{-4}$	0.0	$7.52x10^{-5}$	$2.17x10^{-3}$	$1.43x10^{-2}$	$1.38x10^{-2}$	$2.9x10^{-2}$
I-135	$2.79x10^{-1}$	$1.90x10^{-1}$	$1.19x10^{-5}$	$2.37x10^{-5}$	$1.92x10^{-5}$	0.0	$6.80x10^{-4}$	$7.22x10^{-4}$	$4.78x10^{-3}$	0.0	$4.8x10^{-3}$
Cs-136	$1.30x10^{1}$	$1.30x10^{-2}$	$3.08x10^{-6}$	$9.18x10^{-4}$	$5.16x10^{-5}$	0.0	$3.21x10^{-5}$	$10.02x10^{-4}$	$6.64x10^{-3}$	0.0	$6.6x10^{-3}$
Cs-137	$1.10x10^{4}$	$1.80x10^{-2}$	$4.73x10^{-6}$	$1.43x10^{-3}$	$7.67x10^{-5}$	0.0	$5.01x10^{-5}$	$1.57x10^{-3}$	$10.36x10^{-3}$	$2.55x10^{-2}$	$3.6x10^{-2}$
Ba-137m	$1.77x10^{-3}$	$1.60x10^{-2}$	$7.68x10^{-6}$	$1.37x10^{-3}$	$7.17x10^{-5}$	0.0	$4.69x10^{-5}$	$1.46x10^{-3}$	$9.69x10^{-3}$	0.0	$9.6x10^{-3}$
All Others		$2.53x10^{-1}$	$2.19x10^{-6}$	$4.21x10^{-6}$	$1.95x10^{-7}$	0.0	$4.77x10^{-6}$	$9.18x10^{-6}$	$6.09x10^{-5}$	0.0	$6.1x10^{-5}$
TOTAL (except tritium)		$1.46x10^{0}$	$2.16x10^{-4}$	$1.53x10^{-2}$	$6.78x10^{-4}$	0.0	$1.24x10^{-2}$	$2.84x10^{-2}$	$1.88x10^{-1}$	$6.63x10^{-2}$	$2.6x10^{-1}$

Tritium Release 404 Ci/yr

Table 3-6. Annual Weight, Volume, and Activity of Radwaste Shipped

TYPE OF WASTE	WEIGHT (Tons/day)	SOLIDIFIED VOLUME (ft^3/day)	CATEGORY (S.C)[a]	SHIPPING CONTAINER	CONTAINERS SHIPPED PER YEAR	ACTIVITY (Ci/yr)[b]
Bead Resins[c]	0.452	9.329	S	DOT 17C 55 gal. drum	464	10,000
Disposable Filter Elements	0.185	4.132	S	DOT 17H	201	315
Evaporator Concentrates	5.101 to 5.888	94.14 to 107.01	S	DOT 17C 55 gal. drum	4,680 to 5,253	516
Compressed Waste (including pre- and HEPA filters)	0.131 to 0.146	11.78 to 13.35	C	DOT 17H 55 gal. drum	593 to 669	very low activity

[a] Key to radwaste category:

S - Solidified prior to shipment
C - Compacted, rags, paper, compressible waste

[b] Activity at time of drumming except as noted

[c] The spent resin activity (bead resins) is calculated at the time the resin is transferred to the spent resin tank. This activity will be less if the resin is stored for a significant period of time.

4.2 LAND AND WATER USE

Approximately 500 acres would be required for the primary plant site. This area includes an exclusion area of roughly 200 acres necessary for the positive control of all activities at the site. As shown previously in Figure 3-1, the site also has sufficient room for the construction of a second nuclear unit next to the original unit.

Consumptive water use results primarily from cooling tower evaporative losses, cooling tower blowdown, and general plant uses. By far, the largest consumers of water are the mechanical draft cooling towers. These towers use approximately 1 million gallons/hr. Table 3-7 identifies this and other plant water uses.

Table 3-7. Water Use in a 1250 MWe Light Water Reactor

WATER USE	Million Gallons/Day	
	100% Power	70% Power
Cooling Tower Evaporation	24.5	17.2
Cooling Tower Blowdown	7.1	5
General Plant Use	< 1	< 1
TOTAL	32.6	23.2

The primary sources of liquid effluents from a LWR facility include the cooling tower blowdown stream and process water effluent. No radioactive wastes are discharged in effluent streams. Rather, these waste streams, which are processed to remove radionuclides, are then discharged under controlled conditions. Cooling tower blowdown does not contain any radionuclide contamination but does contain chemicals added for corrosion and biological growth control. Typical liquid effluent discharges must meet discharge limitations. The discharges are listed in the following table.

Table 3-8. Waste Water Effluents - 1250 MWe LWR Facility at 70% Capacity Factor [9]

Pollutants	Tons/Day
Total Suspended Solids *	1.043
Total Dissolved Solids*	2.608
Organics	0.21
Chlorine	0.1
Copper	2.8
Chromium	0.01
Phosphate	0.13

* Assuming a concentration factor of 4.5 tons/day in the cooling tower with 10 ppm TSS and 25 ppm TDS concentrations in the makeup water.

5.0 CONSTRUCTION AND OPERATION CHARACTERISTICS

The construction of an LWR facility is subject to delays. Some delays have been experienced because of:

- Litigation
- Financial problems
- Large changes in the need for power
- Licensing requirements for facility changes and back fits
- Licensing holds

There are also other reasons for extended construction periods that have been experienced. Without any of these delays, a 1240 MWe LWR facility could be constructed in 6 years. If the delays expected to occur are included in this estimate, and licensing is also included (a two-step process with a construction permit and operating license included), the LWR facility could be completed in 12 years. (Recent experience is showing a trend toward 12-year construction times). During the on-site construction period, an estimated 11.54 million man-hours of direct craft labor would be required primarily from 16 different labor types as detailed in Table 3-9. Indirect labor hours are also included in the table.

Normal operation of the facility would require a plant staff averaging 215 persons and over 430,000 man-hours per year as shown in Table 3-10. The number of personnel on-site would vary considerably from time to time depending on the operation of the unit. When the unit is down for refueling/repair, the total number of personnel on-site would peak at a number considerably higher than 215.

Table 3-9. Direct Craft Labor Summary - 1250 LMFBR Plant
Cost Basis - July, 1976

CRAFT DESCRIPTION	SITE LABOR HOURS	% HOURS
Asbestos Worker	121,776	1.1
Boiler Maker	678,055	5.9
Bricklayer	129,520	1.1
Carpenter	1,379,305	12.0
Dock Builder	3,255	0.0
Electrician	1,858,431	16.1
Iron Worker	1,316,709	11.4
Laborers	1,299,695	11.3
Millwrights	172,227	1.5
Operating Engineers	864,766	7.5
Painters	203,580	1.8
Pipefitters	3,193,846	27.6
Plumbers	682	0.0
Roofers	12,775	.1
Sheet Metal Workers	125,700	1.1
Teamsters	175,892	1.5
TOTAL DIRECT LABOR	11,536,214	
INDIRECT LABOR	1,993,921	
CONSTRUCTION SERVICES	1,993,921	
TOTAL	15,524,056	100.0

Table 3-10. Staff Requirements for LWR Plant*

AREA	PERSONNEL
Plant Manager's Office	1
Manager	1
Assistant	1
Quality Assurance	3
Environmental Control	1
Public Relations	1
Training	1
Safety	1
Administrative Services	13
Health Services	1
Security	56
SUBTOTAL	79
Operations	
Supervision (excluding shift)	2
Shifts	33
SUBTOTAL	35
Maintenance	
Supervision	8
Crafts	16
Peak Maintenance Annualized	55
SUBTOTAL	79
Technical and Engineering	
Reactor	1
Radiochemical	2
Instrumentation and Controls	2
Performance, Reports and Technicians	17
SUBTOTAL	22
TOTAL	215

* Single unit 701-1300 MWe

5.1 OPERATING STATISTICS AND ANNUAL GENERATION

Historical statistics on nuclear power generation facilities of this type indicate that the overall plant capacity factor would be 70%. That is, the plant would produce 70% of the maximum possible kilowatt hours it could generate if it were operated continuously at full capacity.

Numerous parameters combine to produce this factor. These include plant downtime for scheduled maintenance plant forced outage rate due to unexpected component failure, and the customer load profile (including inter-utility sales of electricity). The first two factors combine to determine plant availability, while the inclusion of customer demand results in the plant capacity factor.

Typically, a large nuclear station, such as the type characterized here, would be placed first (or at least close to first) in the utility's loading order. Thus, it would not be affected by customer demand, since it could serve to satisfy part of the minimum customer load. If operated properly, all of the unit's output would be used to meet customer demand.

Scheduled maintenance and affecting outages for large nuclear facilities vary between 4 to 6 weeks per year. Recent forced outage rates range from 5 to 20.4 percent. In this case, 6 weeks of maintenance and refueling and a 20.4 percent forced outage rate is used to conservatively determine unit availability. Thus, plant availability is determined by:

$$\text{Plant Availability} = \frac{52-6}{52} \times (1-0.204) \times 100\% = 70\%$$

At this availability and capacity factor, the reference 1250 MWe LWR facility would generate 7.665×10^{9} kilowatt-hours per year.

6.0 COST CHARACTERIZATION

The basic capital costs estimated for the 1250 MWe reference light water reactor plant have been derived from detailed cost data presented in the "Energy Economic Data Base (EEDB) Program Phase I" report prepared for DOE by United Engineers and Constructors. Direct and indirect capital costs presented in the EEDB are on a consistent January 1, 1978 dollar basis. These costs are for the 1139 MWe (3425 MWt) Westinghouse reactor plant which provided the basis for the physical system characterization presented in the previous sections.

6.1 DIRECT CAPITAL COSTS

The EEDB costs have been appropriately adjusted to reflect increased power levels and flow rates incorporated into the 1250 MWe reference light water reactor system. Specifically, the major modifications that affect the reference system's capital costs (as compared to the 1139 MWe EEDB design) include a 9.8% increase in the following system component capacities and design characteristics:

1. Main coolant flow through reactor vessel
2. Steam flow through steam generators and turbines
3. Turbine shaft power, generator output, net plant capacity, and heat rejection system

Base direct capital costs includes the costs of all materials, components, structures, and associated direct craft labor necessary to construct the reference facility at the plant site. Delivered costs for components, structures, and materials are used. Base indirect costs include site temporary construction facilities, payroll insurance and taxes, and other construction services, such as, home and field office expenses, field job supervision, and engineering services. Specifically excluded from the base construction cost estimate are several items that are sensitive to the particular policies and preferences of the individual utility and to the specific plant site and prevailing economic factors being considered. These exclusions include the following list of items:

1. Owner's Costs - Consultants, Site Selection, etc.
2. Federal, State and Local Fees, Permits and Taxes

3. Interest on Capital Construction Funds

4. Price Escalation during Construction

5. Contingency Funds

6. Owner's Discretionary Items - Switchyard and Transmission Costs, Waste Disposal Costs, Spare Parts, and Initial Fuel Supplies

By reviewing the detailed cost estimates made in the EEDB for the 1139 MWe reactor design at the "3-digit" subaccount level, we were able to estimate the 1250 MWe reference light water reactor system costs. Where appropriate, we adjusted the costs using the capacity ratio-exponent estimating technique. This technique, which is generally accepted by the electric power generation industry for making cost estimate modifications, uses the following equation to adjust component costs for small to moderate changes in component capacity.

$$\text{Cost of Component B} = \text{Cost of Component A} \times \left(\frac{\text{Capacity of B}}{\text{Capacity of A}}\right)^{\alpha}$$

This equation applies where Component A and Component B are of similar design and performance, differing only in size of capacity, and where α is given by the following:

Account	Description	Cost Estimating Exponent (α)
20	Land and Land Rights	Not Applicable
21	Structures and Improvements	.20
22	Reactor Plant Equipment	
	Nuclear Steam Supply System (NSSS)	.40
	Balance of Reactor Plant	.30
23	Turbine Plant Equipment	.85
24	Electric Plant Equipment	.37
25	Miscellaneous Plant Equipment	.20
26	Condenser Heat Rejection System	.50

Table 3-11 shows the original EEDB cost estimate by "2-digit" accounts. Also shown are the applicable cost estimating factors and the resulting 1250 MWe reference system cost estimates. Costs for land would not vary measurably for the small incremental plant capacity considered here, so this account has been assigned a cost estimating factor of unity. The land costs shown assume the use of a 500 acre site valued at $4,480 per acre.

Table 3-11. Estimated Direct Capital Costs for 1250 MWe Light Water Reactor Reference System (January 1, 1978 Dollars)

Account	Description	1139 MWe EEDB[a] Cost $1000	CEM[b]	1250 MWe Reference System Cost $1000
20	Land and Land Rights	2,240[c]	1.00	2,240
21	Structures and Improvements	51,377	$1.098^{0.20}$	52,347
22	Reactor Plant Equip.			
	Nuclear Stream Supply System	73,255	$1.098^{0.40}$	76,046
	Balance of Reactor Plant	45,190	$1.098^{0.30}$	46,475
23	Turbine Plant Equip.	98,656	$1.098^{0.85}$	106,816
24	Electric Plant Equip.	24,301	$1.098^{0.37}$	25,156
25	Misc. Plant Equipment	9,755	$1.098^{0.20}$	9,939
26	Condensate Heat Rejection System	16,161	$1.098^{0.50}$	16,934
	TOTAL DIRECT EQUIPMENT AND MATERIALS	320,935		335,956
	Site Labor Costs	145,132	$1.098^{0.35}$	149,960
	TOTAL DIRECT BASE CONSTRUCTION COSTS	466,067		485,916

(a) EEDB, Energy Economic Data Base
(b) CEM, Cost Estimating Multiplier, see text for discussion.
(c) Assumes 500 acres at $4480/acre.

Average site labor costs for the 1139 MWe EEDB facility are estimated from approximately 11.13 million man-hours at a craft-averaged cost of $13.04 per man-hour. A cost estimating exponent of 0.35 has been used to estimate the direct field labor requirements and costs. Resultant direct craft man-hours for the reference facility are thus estimated to total 11.50 million man-hours, or nearly $150 million.

6.2 INDIRECT CAPITAL COSTS

Indirect capital costs associated with the construction of large light water reactor power plants are relatively insensitive to the plant capacities used in the EEDB. Thus, except for payroll related expenses, indirect capital costs for the 1250 MWe reference light water reactor plant have been taken to be the same as those for the EEDB 1139 MWe plant. Construction payroll related expenses include payroll insurance and taxes as well as field job supervision costs. The latter was to be proportional to the reference system direct field labor costs. This assumption adds $802,000 to the Construction Services account (#91) and $687,000 to the Field Office Engineering and Services account (#93) over those costs estimated in the EEDB.

Indirect capital costs, summarized in Table 3-12 at the "2-digit" account level, total $197,109,000, or about 41% of the direct capital costs estimated for the reference light water reactor system. These costs are more than twice the indirect costs associated with coal burning facilities of similar capacities. Safety and inspection requirements are a major contributor to this factor.

Table 3-12. Estimated Indirect Capital Costs for 1250 MWe Light Water Reactor Reference System (January 1, 1978 Dollars)

Account	Description	1250 MWe Reference System Cost ($1000)
91	Construction Services	74,982
92	Home Office Engineering and Services	91,325
93	Field Office Engineering and Services	30,802
	TOTAL INDIRECT	197,109

6.3 OPERATION AND MAINTENANCE COSTS

Annual operation and maintenance (O&M) costs for the 1250 MWe reference light water reactor facility have been estimated. These costs are based on cost estimating relationships presented in a recent Oak Ridge National Laboratory (ORNL) document entitled, "A Procedure for Estimating Nonfuel Operation and Maintenance Costs for Large Steam Electric Power Plants," and on data available in the EEDB.

Generally, O&M costs for a nuclear power plant may be considered to be composed of six cost categories. The costs may be either fixed (not dependent on annual generation) or variable. The six categories considered here include: Plant Staffing, Maintenance Materials, Plant Supplies and Expenses (including radioactive waste disposal), Nuclear Liability Insurance and Inspection Fees, Interim Replacements and Administrative, and General Expenses.

Plant staffing costs are based on the 215 person plant staff described earlier and assumes a cost of $22,000 per person per year. Maintenance materials have been found to average 100% of the maintenance staff costs (79 persons) for large nuclear generation plants and also have been found to be insensitive to plant capacity factors, thus, considered all fixed expenses. Fixed supplies and expenses, which include makeup chemicals, lubricants, and auxiliary fuels, as well as offsite contract services, radioactive waste management (exclusive of fuel), and non-radioactive waste management, have been estimated in the ORNL report to be $4.3 million per year with a variable component of .06 mills/kWh. Nuclear liability insurance and inspection fees are estimated at $409,000 per year with roughly 75% of this amount for private and government nuclear liability insurance. Administrative, overhead, and utility home office general expenses associated with the reference facility are estimated by ORNL to be 15% of the combined staff costs and fixed components of the materials and supplies costs. This compares to 10% of the same cost components for a conventional coal burning facility, with the increase primarily resulting from the larger amount of record keeping and safety related administrative costs necessary for the nuclear facility. Table 3-13 summarizes the O&M costs for the reference nuclear light water reactor facility.

Table 3-13. Annual Operation and Maintenance Costs--1250 MWe Reference Nuclear Light Water Reactor Facility @ 70% Capacity Factor

O&M Cost Account	Cost Estimating Relationship	($1000)
Plant Staff	215 persons @ $22,000/yr (Fixed Cost)	4,730
Maintenance Materials	Fixed: 79 persons x 22,000 $/yr x 1.0 Variable: None	1,738
Supplies & Expenses	Fixed: Chemicals, gases, lubricants, auxiliary, fuels, etc.	2,400
	Offsite Contract Services	900
	Radioactive Waste Management[a]	900
	Non-radioactive Waste Management	100
	Variable:	
	$\frac{(.06 \text{ mills/kWh})(1,250,000 \text{ kW})(6,132 \text{ hr/yr})}{1000 \text{ mills/\$}}$	460
Insurance and Inspection Fees	Nuclear Liability Insurance Premiums (Fixed Cost)	308
	Inspection Fees (Fixed Cost)	100
Interim Replacements	Sinking Fund accrual of 30% of direct and indirect plant capital costs at 30 years and 4% interest (Fixed Cost)	3,647
Administrative and General	15% of Staff, Maintenance Materials and Fixed Supplies & Expenses (Fixed Costs)	1,615
	TOTAL O&M COSTS	16,898

At 70% Capacity Factor:

Fixed O&M Costs:	$\frac{(16,438,000 \text{ \$/yr})(1000 \text{ mills/\$})}{(1,250,000 \text{ kW})(8760 \text{ hr/yr})(.7)}$	=	2.14 mills/kWh
Variable O&M Costs:	$\frac{(490,000 \text{ \$/yr})(1000 \text{ mills/\$})}{(1,250,000 \text{ kW})(8760 \text{ hr/yr})(.7)}$	=	.06 mills/kWh
	TOTAL O&M COSTS		2.20 mills/kWh

(a) Includes materials, packing, 1000 miles transportation, and final disposal costs.
(b) Annual hours of operation at 70% capacity factor.

7.0 NUCLEAR FUEL CYCLE

This section of the report will characterize the nuclear fuel cycle for the LWR operating on a once-through fuel cycle. Figure 3-3 shows this fuel cycle. Figure 3-3 includes permanent disposal of the spent fuel in a geologic repository after a cool down period in the onsite fuel pool or at away-from-reactor (AFR) storage.

During each of the phases of the fuel cycle, liquid, solid, and gaseous effluents are produced to reject heat. The following subsections quantify these emissions relative to providing fuel for a 1250 MWe nuclear power reactor. The primary sources of information are listed as references 3 and 7, and were representative of a 1000 MWe facility. Since the reference facility is a 1250 MWe unit, linear scaling was used in the following characterization.

7.1 AIR EMISSIONS(3, 7)

7.1.1 Mining

- Chemical (tons/day)

SO_2	:	0.013
NO_x	:	0.003
Hydrocarbons	:	0.000
CO	:	0.000

The primary chemical gaseous effluents derive from the burning of fossil fuels. Mining is accomplished by conventional deep mining techniques and open pit mining techniques. Standard diesel-fueled mining equipment is assumed.

- Radiological

Uranium and its daughters are released to the atmosphere when the ore body is exposed and broken up during underground or open pit mining operations. The airborne radionuclides discharged from underground mines are rapidly diluted by forced air circulation and atmospheric dispersion to normal background levels at the site boundaries. Attempts by the Bureau of Mines to measure radon concentrations in existing open pit mines revealed no significant alpha concentrations. Therefore, the concentrations of airborne radionuclides in unrestricted areas are expected to be undetectable. Mine tailings piles which have caused so much recent concern about radon emissions are scheduled to be cleaned up prior to year 2000.

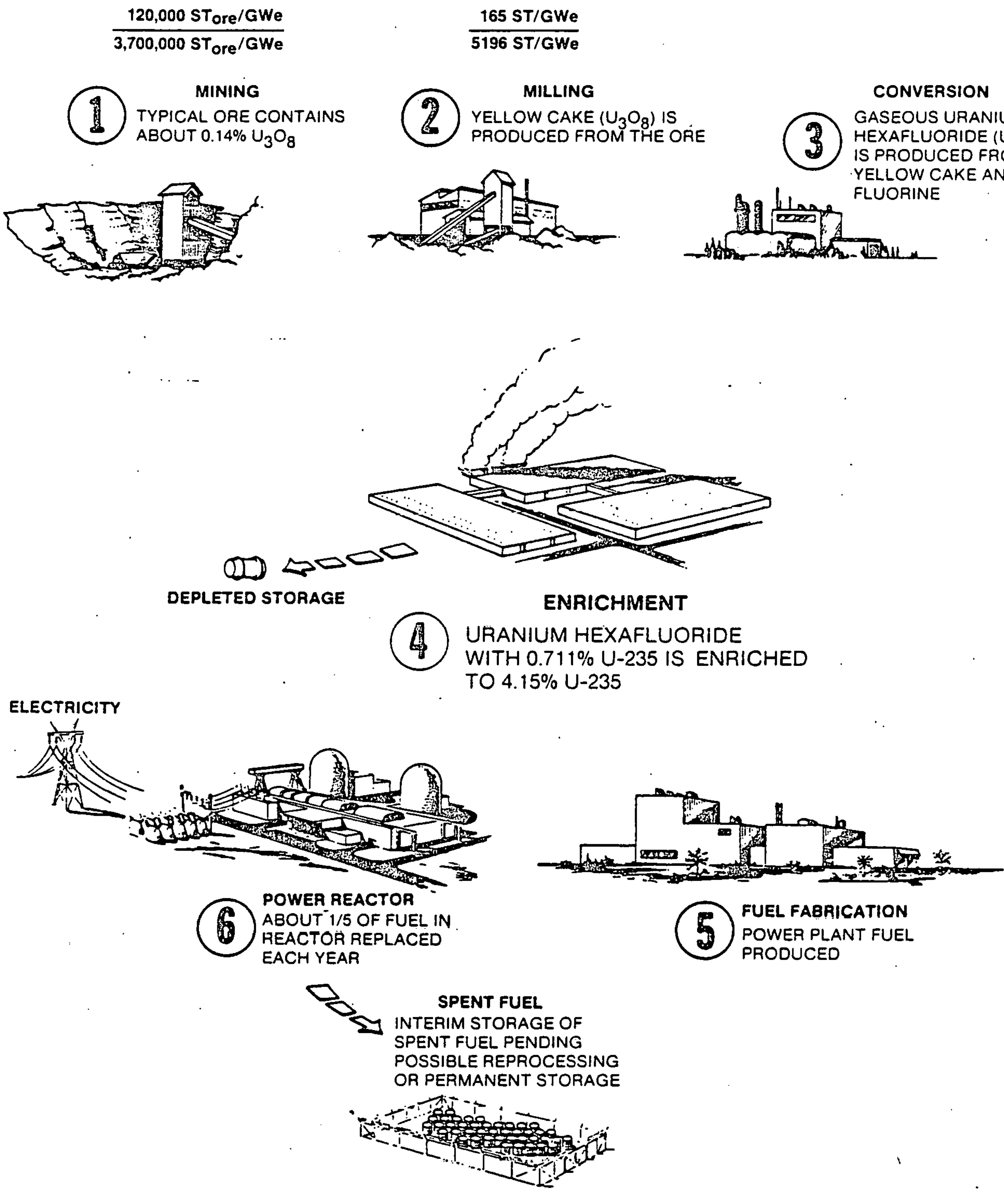

Figure 3-3. LWR Fuel Cycle

7.1.2 Milling

- Chemical (tons/day)

SO_2	:	0.140
NO_x (40% from natural gas use)	:	0.060
Hydrocarbons	:	0.005
CO	:	0.001

- Radiological (curies/year)

Rn-222	:	93.1
Ra-226	:	0.02
Th-230	:	0.02
U (natural)	:	0.03

In addition to the gaseous effluent release associated with the generation of electric power required by the mill, small quantities of sulfuric acid fumes, kerosene, and dust are released to the atmosphere from the uranium mill processes. In all cases, the airborne concentrations of these contaminants are maintained well below EPA standards. Deleterious effects on biota are highly unlikely.

Low level radiological airborne effluents consist of uranium and uranium daughter products. Conservative estimates of dispersion in the atmosphere predict site boundary concentrations in the range of less than 1% to 14% of the limits of 10 CFR 20.

7.1.3 Uranium Hexafluoride Production

- Chemical (tons/day)

SO_2	:	0.109
NO_x	:	0.038
Hydrocarbons	:	0.002
CO	:	0.000
F^-	:	0.000

The emissions of SO_2 and CO are effluent gases from combustion of equivalent coal for power generation. The effluents NO_x and Hydrocarbons come from the combustion of coal and natural gas.

A number of process off-gases are generated in the preparation of UF_6 from yellowcake. Most of these are combustion products but some are volatized solids and gases evolved during calcining and fluorination. Several off-gas treatments are applied to minimize the concentrations of airborne effluents released to the environment. Fluorides and oxides of nitrogen are the more significant sources of potential adverse environmental impact. Historically, analyses of airborne concentrations of fluoride as HF in air and concentrations in forage in the vicinity of a wet solvent extraction plant indicate fluoride levels below those expected to cause deleterious effects on human health or grazing animals. Long-term observation of an area within a 7-mile radius of a hydrofluoride plant has not revealed any adverse effects attributable to fluoride releases from the plant.

- Radiological (curies/year)

  Uranium: 0.017

7.1.4 Uranium Enrichment

- Chemical (tons/day)

	Gaseous Diffusion	Centrifuge
*SO_2 :	16.200	.648
*NO_x :	4.256	.170
*Hydrocarbons:	0.041	.002
*CO :	0.106	.004
F^- :	0.002	.002
*Particulates:	4.256	.170

Starred estimated effluent gases are based upon combustion of equivalent coal for power generation assuming 100% load factor.

The primary source of environmental impact associated with the enrichment of uranium is related to the gaseous effluents from the coal-fired stations used to generate the required electric power.

Small quantities of airborne fluoride are generated at the diffusion plants. Measurements in unrestricted areas indicate concentrations which are below the range for which deleterious effects have been observed, and span the most restrictive State standard. In addition, oxides of nitrogen and sulfur are released at the diffusion plants. Conservative estimates of the off-site concentrations of these contaminants yield levels which are slightly below or are at EPA standards. Furthermore, the total quantity of these effluents is insignificant in comparison with the combustion products generated by the supporting electric power plants.

The centrifuge enrichment process is scheduled to start operation in 1987. This process was only 4% of the power requirement of the diffusion process. Both processes will be operating in year 2000, and since SWH's will be produced at both facilities, origin cannot be firmly assumed. Hence, both processes are listed above.

- Radiological (curies/year; based on 4.15% isotopic enrichment)

  Uranium: 0.003

7.1.5 Fuel Fabrication

- Chemical (ton/day)

*SO_2	:	0.086
*NO_x	:	0.022
*Hydrocarbons	:	0.000
*CO	:	0.001
F^-	:	0.000

Starred compounds in effluent gases are from combustion of coal for power generation.

The most significant effluents from the standpoint of potential environmental impact are chemical in nature. Nearly all of the airborne chemical effluents result from the combustion of fossil fuels to produce electricity to operate the fabrication plant. The only significant airborne chemical effluent from the process operations of the fabrication plant is fluorine. The fluorines which was introduced into the fuel cycle during the UF_6 production phase, becomes a waste product during the production of UO_2 powder. The gaseous fluorine wastes generated are effectively removed from the air effluent streams by water scrubber systems. These wastes result in a site boundary concentration of roughly 6% of the most restrictive of a reference state's standard, 0.5 $\mu g/m^3$.

- Radiological (curies/year)

  Uranium: 0.000

7.1.6 Power Plant

The expected annual average release of airborne radionuclides is discussed in the previous section.

7.1.7 Waste Management (AFR Storage and Final Disposal)

No gaseous emissions are expected apart from those due to coal combustion which would provide the electricity for site operation.

7.1.8 Transportation

The primary source of gaseous emissions would be the combustion of approximately 13,400 gallons of diesel fuel resulting primarily in approximately 0.004 tons/day of NO_x.

7.2 LIQUID EFFLUENTS[3, 7]

7.2.1 Mining

The drainage water carries some suspended solids. The water quality can be nearly restored by settling pond treatment and natural seepage. Mine drainage water results from production necessary to supply the annual fuel requirement of the model LWR. The water can contain as much as several curies of radioactivity. This radiological liquid effluent results from dissolved and suspended uranium and its daughter nuclei. The activity is removed from the water and returned to the ground by ion exchange during seepage through the soil. When it is economically feasible, the uranium values are recovered from the mine water before it is discharged.

7.2.2 Milling

- Chemical (tons/day)

  Tailings Solutions: 904

Liquid and solid chemical and radiological wastes are discharged to the tailings retention pond. Operating experience has indicated that no significant adverse effect on the off-site environment is involved. After the model plant is decommissioned, the pond area is graded, covered with earth, and restored for limited use.

- Radiological (curies/year)

  Uranium and daughter nuclei: 1500

7.2.3 Uranium Hexaflouride Production

- Radiological (curies/year)

  Ra-226: 0.034

  Th-230: 0.034

  Uranium: 0.034

There are two major aqueous effluent streams associated with UF_6 production. Many of the contaminants in this liquid effluent are in the raffinate stream from the solvent extraction process. The contaminants are not released to the environment but held indefinitely in sealed ponds. The second stream is made up mostly of cooling water and dilute scrubber solutions which represent the bulk of the water use. These aqueous effluents are treated with calcium to precipitate calcium flouride and diluted with all remaining clear water effluents from the plant before they are released. The solid calcium fluoride is recovered from settling ponds. Then they are packaged and, ultimately, buried.

7.2.4 Uranium Enrichment

- Chemical (tons/day)

  Ca^+: 0.020
  Cl^-: 0.031
  Na^+: 0.031
  $SO_4^=$: 0.020
  Fe : 0.001
  NO_3^-: 0.010

A number of chemical species are present in the liquid effluent stream from the plant. Calcium, chloride, sodium, and sulfate ions are major constituents of this stream. The concentrations of chemicals, however, undergo considerable dilution before reaching the receiving river. Additional dilution within the receiving river reduces all concentrations well below recommended permissible water quality standards.

- Radiological (curies/year based on 4.15% isotope separation)

  Uranium: 0.02

Small fractions of a curie of uranium in gaseous liquid effluents are introduced into the environment. The result is concentrations in offsite air and water media which are less than 0.1% of the limits of 10 CFR 20.

7.2.5 Fuel Fabrication

- Chemical (tons/day)

  N as NH_3: 0.032

  N as NO_3^-: 0.020

  F^- : 0.001

The most significant chemical species in liquid effluents are nitrogen compounds that are generated from the use of ammonium hydroxide in the production of UO_2 powder and from the use of nitric acid in scrap recovery operations. The nitrogen concentrations in liquids released from the waste holding pond are about 420 mg/liter in the form of ammonia and 280 mg/liter in the form of nitrates. The limiting concentration is for ammonia and requires dilution in the receiving stream by approximately three orders of magnitude. Depending on the nature of the receiving stream and its downstream uses, the nitrogen releases could constitute a significant impact on the environment.

Water from the scrubber systems is combined with process liquid wastes and treated with lime to form a calcium fluoride (CaF_2) precipitate, which is removed by filtration. The 32.50 metric tons of CaF_2 filtered from the liquid per 1250 MWe LWR annual fuel requirement has a volume of about 13.75 cubic yards and is buried onsite with minimal disturbance of land.

The small percentage of fluoride which is not removed by the lime treatment is released from the liquid waste holding ponds at a concentration of about 16 mg/liter. Dilution in the receiving stream by approximately one order of magnitude is required to reduce this concentration to acceptable levels.

- Radiological (curies/year)

  Uranium: 0.021

  Th-234 : 0.010

7.2.6 Radioactive Waste Management

No effluents to the off-site environment are expected.

7.2.7 Transportation

Non-significant level of effluents

7.3 SOLID WASTE[3, 7]

7.3.1 Mining

The primary solid waste material is the barren rock and earth overburden, the bulk of which is ultimately returned to the open pit as backfill.

7.3.2 Milling

- Chemical : Tailings, 0.342 tons/day
- Radiological: Uranium and daughter nuclei, 1500 curies/year

7.3.3 Uranium Hexafluoride Production

- Chemical : 0.150 tons/day
- Radiological: 0.363 curies/year

The source of the radioactivity is from Thorium and occurs in the solid ash residue from hexafluoridation.

7.3.4 Uranium Enrichment

No significant effluents

7.3.5 Fuel Fabrication

- Chemical : Calcium flouride, 0.098 tons/day
- Radiological: Uranium, 0.076 curies/year

7.3.6 Radioactive Waste Management

No effluents to the off-site environment are expected

7.3.7 Transportation

No significant level of effluents

7.4 WASTE HEAT[3, 7]

7.4.1 Mining

Approximately 313 MWh of electricity are consumed to meet annual fuel requirements for 1250 MWe reactor. No significant environmental effects of heat release are anticipated.

7.4.2 Milling

0.236×10^9 Btu/day will be discharged to the atmosphere. The effect on the environment will be undetectable except for some local fogging under certain meteorological conditions.

7.4.3 Uranium Hexafluoride Production

0.103×10^9 Btu/day will be discharged. No significant environmental effects are anticipated.

7.4.4 Uranium Enrichment

10.96×10^9 Btu/day will be discharged. Approximately 67% of this heat is discharged by the electric generating plants servicing the enrichment plant (assuming 100% load factor for generating plant). Since the power is drawn from the grids of large utility complexes, the environmental impact is difficult to evaluate. The heat rejection at the enrichment plant site is largely to the atmosphere. Although occasional misting and fogging results within the site from operation of cooling towers, the thermal impact is insignificant.

7.4.5 Fuel Fabrication

0.031×10^9 Btu/day will be discharged. The thermal load carried by the cooling water is dissipated to the air when the water passes through the liquid waste holding pond and treatment ponds before it is released offsite.

7.4.6 Radioactive Waste Management

No effluents to the off-site environment are expected.

7.4.7 Transportation

Only the shipment of solid high level waste material will involve the release of a measurable but insignificant quantity of heat to the atmosphere.

7.5 DISRUPTION OF LAND AREAS[3, 7]

7.5.1 Mining

Temporarily committed undisturbed area	:	47.6 acres
Temporarily committed disturbed area	:	21.0 acres/year
Permanently committed	:	2.6 acres/year
Overburden moved	:	10,159 tons/day

7.5.2 Milling

Temporarily committed, undisturbed area	:	0.26 acres (major portion included in mine land use)
Temporarily committed, disturbed area	:	0.37 acres
Permanently committed (limited use)	:	2.96 acres

Of the approximately 3.6 acres of total land usage attributable to the model LWR annual fuel requirement, approximately 2.94 acres are devoted to a pond for the permanent disposal of mill tailings. In effect, nearly the entire mass of ore processed by the mill will be discharged to the tailings pond. Although the model plant tailings pond area will be restored to resemble the surrounding terrain after the 20 years of plant life, the land will most likely be removed from further restricted use, except (possibly) grazing.

7.5.3 Uranium Hexafluoride Production

Temporarily committed undisturbed area	:	2.87 acres
Temporarily committed disturbed area	:	0.31 acres
Permanently committed area	:	0.02 acres

7.5.4 Uranium Enrichment

Temporarily committed undisturbed area	:	0.74 acres
Temporarily committed disturbed area	:	0.26 acres
Permanently committed area	:	None

7.5.5 Fuel Fabrication

Temporarily committed undisturbed area	:	0.20 acres
Temporarily committed disturbed area	:	0.04 acres
Permanently committed area	:	None

7.5.6 Power Plant

The total cultivated agricultural land to be affected by the construction and operation is 500 acres. This includes an area for geographic isolation.

7.5.7 Radioactive Waste Management

Less than .21 acres for storage of both high-level and other-than-high-level wastes.

7.5.8 Transportation

None

7.6 MANPOWER REQUIREMENTS

The exploration, mining, and milling of uranium ore is labor intensive. Mining and milling usually occur at or near the mine. Consequently, employment is usually expressed for all three functions (exploration, mining, milling). Recent data indicates the following:

Annual Production ore	:	9,198,000T
U_3O_8 Content	:	14,000T
Employment	:	12,612
Productivity (ore)	:	729T/man-year

8.0 REFERENCES

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SECTION 4. COMBINED CYCLE WITH INTEGRAL LOW-Btu GASIFICATION

4. COMBINED CYCLE WITH INTEGRAL LOW-Btu GASIFICATION

1.0 INTRODUCTION

This plant design is an integrated system, primarily consisting of a gasifier, an open cycle gas turbine, and a Rankine bottoming cycle. The basic cycle is modeled after a 579 MWe plant described in the Energy Conversion Alternatives Study (ECAS) (Reference 1). Reference was also made to other sources, such as the EPRI Preliminary Design Study for an Integrated Coal Gasification Combined Cycle Plant (Reference 2). The plant design was scaled to 1250 MWe.

The ECAS design utilizes the Alkazid desulfurization process system for gas cleaning and a mechanical draft cooling tower for condensate heat removal. At the time of its design (1977), this system just met the Environmental Protection Agency (EPA) new source performance standard (NSPD) for SO_2 emissions of 1.2 lb/10^6 Btu by scrubbing about 88% of the gasifier output at a 90% removal efficiency. More recent EPA regulations now require a 90% removal of all stack gas SO_2 for a facility of this type, and total SO_2 are not to exceed an upper limit of 1.2 lb/10^6 Btu. Since SO_2 and NO_x emissions are likely to be more severely restricted in the future, ECAS also produced an alternative design to comply with the gaseous fuel standards of 0.2 lbs/10^6 Btu for SO_2 (and 0.7 lbs/10^6 Btu for NO_x). The plant designed for these more stringent standards had 99% of the output of the baseline plant. Its capital costs were 11% higher and its electricity costs 8% higher than the plant designed to less stringent emission standards. This design has been modified by ANL to comply with 40 CFR Part 60, Standards of Performance for New Stationary Sources, Gas Turbines. Promulgated on September 10, 1979, these standards apply to the gas turbine portion of a combined cycle steam/electric generating system. They limit the concentrations of exhaust gases as follows:

- NO_x limited to 75 ppm
- SO_2 limited to 150 ppm

At 15 percent oxygen and on a dry basis, this is equivalent to:

- NO_x = 0.34 lbs/10^6 Btu of Fuel Gas
- SO_2 = 1.47 lbs/10^6 Btu of Fuel Gas

The characterization provided here is of a year-2000, 1250 MWe high sulfur coal combustion facility with a suitable sulfur removal process. The plant capacity factor is assumed to be 70 percent. It is also assumed that the plant's fuel gas is processed to remove sufficient sulfur compounds to comply with the applicable standards. Although it is possible to achieve this removal efficiency with the Alkazid process, advances in sulfur removal systems anticipated between now and the year 2000 were taken into account. Other proprietary processes, such as Selexol (Allied Chemical Corporation) and Stretford, could also be used to achieve adequate sulfur removal.

In this evaluation, such factors that are included are: (1) meeting other emission standards and (2) using alternative sulfur removal processes.

2.0 GENERAL PLANT CONFIGURATION

The plant arrangement drawings, showing the power plant equipment arrangement and the provision for onsite fuel and waste storage, are prepared for a typical plant site. The plant consists of two identical subplants, each producing one half of the full generating capacity.

Figure 4-1 shows the plant area which is surrounded by a perimeter road and has a 60-day dead storage coal pile and a 3-day live storage capacity. Storage facilities are provided for 15-day storage of ash discharged from the gasification module and sulfur generated from the Claus plant. The LBtu fuel plant and the power generation area are located adjacent to each other. Other plant support facilities, the switchyard and cooling towers, are also situated in the plant area. Important plant areas are described below.

2.1 COAL HANDLING AND STORAGE

The compacted dead storage pile is 50 ft high with a base covering about 8.2 acres. This pile stores 480,720 tons of Eastern high sulfur coal for recovery with dozer tractors. Two conical live storage piles are provided covering an area of about 0.87 acres. These piles contain a total of 25,301 tons of coal available by gravity fed through underpile vibrating feeders to a conveyor belt that lifts the coal to feed hoppers. The hoppers supply coal to the coal dryer and then to the crusher; the crushed overscreened coal (1/4 to 2 in) and the unscreened fines (0 to 1/4 in) are supplied to four gasification modules by parallel conveyors at an average combined feed rate of 502 tons/hr.

2.2 LBtu FUEL PLANT

The fuel plant consists of two gasification modules and gas cleanup systems. Each gasification module has two rows of 8 gasifier vessels each. The total plant requirement is for 32 gasifier units. Normal operation will require 26 gasifiers on line, with 6 gasifiers in reserve or repair.

If more advanced entrained gasifiers are eventually used in this plant, then the number of gasifier modules would be smaller, (about 5 to 10). The entrained gasifiers are larger, with capacities up to 100 tons/hr. The cleanup system includes: (1) a series of heat exchangers to cool the raw

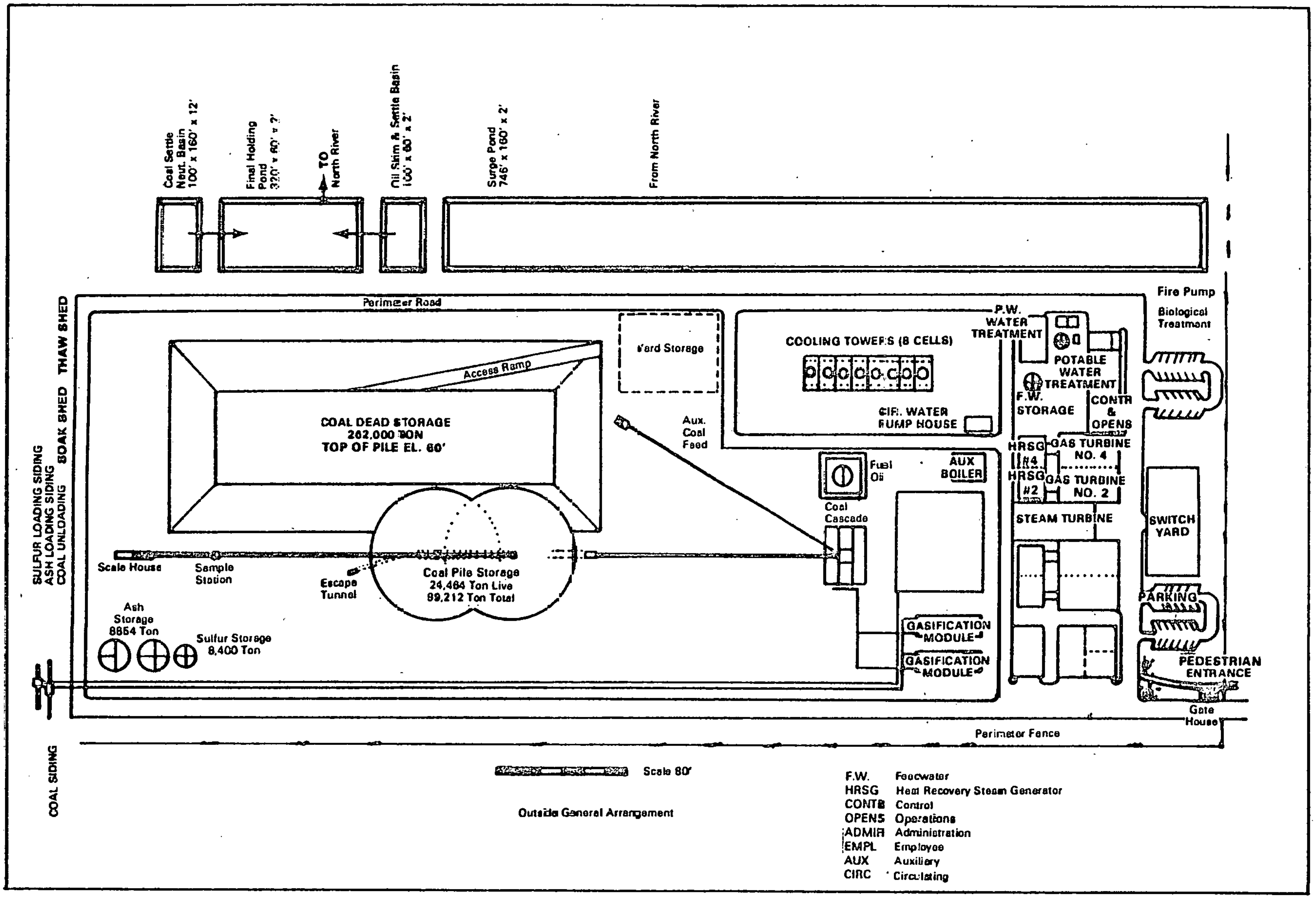

Figure 4-1. 1250 MWe Reference Coal Gasification Power Facility

gas, (2) a Claus plant to convert H_2S to elemental sulfur, and (3) an incinerator.

2.3 POWER GENERATION AREA

This area includes two sets of four gas turbines. Each turbine is connected to a heat recovery steam generator (HRSG). The steam turbine building includes a reheat steam turbine, steam condenser and associated feedwater heaters, and pumps. The arrangement provides eight separate and parallel turbine gas flow paths, permitting independent operation of each gas turbine.

2.4 SOLID WASTES HANDLING

Ash from the gasification modules and dry sulfur from the Claus plants of the gas cleanup process are the solid waste products for this plant. Ash is produced at a nominal rate of 51.2 tons/hr which is conveyed to loading silos at the rail spur. A standby ash storage capacity of 18,425 tons is provided by two storage silos. Sulfur is produced at a nominal rate of 15.7 tons/hr. This is also conveyed to a loading silo at the rail spur. Two storage silos provide standby dry sulfur capacity of 5,672 tons.

2.5 COOLING TOWERS

For this plant, with a heat rejection load of 1.59×10^9 Btu/hr, sixteen cooling tower cells and a water circulating capacity of 104, 153 gpm were used.

2.6 PONDS

The surge pond and the waste-water pond have been sized for 3-day and 12-hour capacities, respectively. The pond area is 32 acres.

2.7 LOGISTICS AND OPERATION

Coal is delivered by unit trains to the fuel handling area adjacent to the coal storage piles. The fuel handling system has all of the necessary equipment to handle the coal gondolas in which the coal is supplied. There are facilities for thawing the cars in winter and a rotary car dumper. From the storage piles, the coal is moved by front-end loaders to a conveyor system. The coal is dryed, crushed, and remoisturized before being fed to lock hoppers on the gasifier. The coal is reduced to ash in the gasifier. About 99.9% of the ash is removed through the ash hopper lock at the bottom of the gasifier. The ash is consolidated and then permanently disposed of at an adjacent site. About 98% of the sulfur is removed from the Claus sulfur recovery unit either for sale or disposal.

The gasifier output (fuel gas) goes to the gas turbine. The gas turbine exhaust drives the Rankine heat recovery (bottoming) cycle. The exhaust of the heat recovery boilers goes to the plant stack.

The main heat rejection system includes a makeup water intake and discharge, circulating water pump, and several mechanical draft wet cooling towers. Waste heat from the thermodynamic cycle is rejected to the steam cycle condensers in the form of heated water. Cooler water from the cooling towers circulates through the condensers to remove this heat and rejects it to the atmosphere in the form of convective and evaporative losses.

3.0 THERMODYNAMIC CYCLE CHARACTERISTICS

The reference high sulfur coal generation facility is fired with Eastern High Sulfur Bituminous coal. The coal as received has a higher heating value (HHV) of 11,026 Btu/lb and other constituents as shown in Table 4-1. The overall net plant efficiency, which accounts for in-plant auxiliary steam and electrical consumption, is 38.5%. This facility thus requires 8,865 Btus of coal feed to produce one kilowatt hour of electricity. Figure 4-2 displays the major pieces of plant equipment in a simplified cycle schematic and energy flow diagram of the reference design.

Table 4-1. Typical Eastern Bituminous High-Sulfur Coal Characteristics

Property or Component	As Received	Dry
Higher Heating Value	11,026 Btu/lb	12,432 Btu/lb
Ultimate Analysis (% by Weight)		
Carbon	61.49	69.33
Hydrogen	3.81	4.30
Sulfur	3.20	3.61
Nitrogen	.76	.86
Oxygen	8.55	9.64
Other	.59	.66
Ash	10.29	11.60
Moisture	11.31	-
	100.00	100.00
Ash Analysis (% by Ash Weight)		
P_2O_5		.05
SiO		45.73
Fe_2O_3		18.38
Al_2O_3		19.40
TiO_2		1.30
CaO		5.50
MgO		.95
SO_3		6.63
K_2O		1.53
Na_2O		.51
Undetermined		.02
		100.00

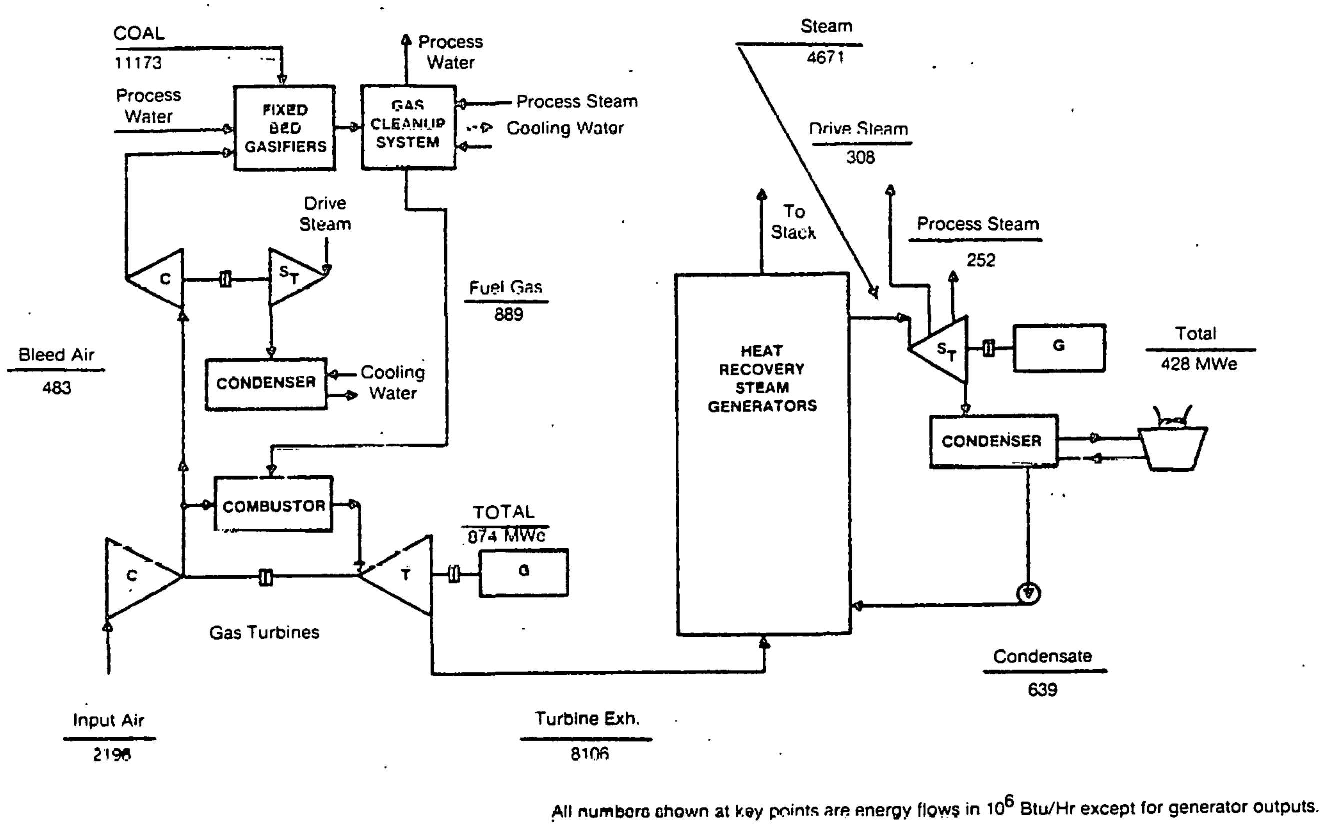

Figure 4-2. Simplified Schematic Diagram of Open Cycle Gas Turbine Combined - Air Cooled - LBtu Gasifier

The fixed bed gasifiers generate LBtu gas which is chemically treated in the gas cleanup system. This ensures that the clean fuel supplied to the gas turbine combustors can meet the applicable SO_x emission standards. The coal is fed to the gasifiers and then the process air required for the gasification process is extracted from the main gas turbine compressors. The process water supplied to the gasifier is preheated in the cleanup system.

The prime cycle consists of eight air-cooled gas turbine generator units, with a 12:1 compressor pressure ratio and 2400°F firing temperature (that is, the temperature at the inlet of the first-stage rotor). The prime cycle generates two-thirds of the total plant electrical power output. The gas turbine exhaust temperature is 1183°F.

The bottoming cycle includes eight heat recovery steam generators (HRSGs) and two steam turbines. The HRSGs extract thermal energy from the gas turbine exhaust stream. The steam is supplied to steam turbine-generators contributing about one-third of the total plant power output.

The steam turbines provide process steam and steam for the booster-compressor-drive turbines.

The process steam is required for the gas cleanup system. Since the plant was designed for baseload service, no provision was made for gas turbine exhaust bypass around the HRSG.

Heat rejection to the cooling tower occurs from the bottoming cycle steam turbine, from the booster-compressor-drive turbine, and from the gas cleanup system. This plant requires 16 mechanical draft wet cooling towers.

The net power output from this plant is 1250 MWe.

3.1 ADVANCED TECHNOLOGIES

The entrained bed gasifier involves a somewhat different thermodynamic cycle than the fixed bed system used as the basis of this analysis. The gasifier operates at lower pressures and higher temperatures than the fixed bed system. More heat is recovered from the gasifier output stream and utilized in the plant's steam cycle. Relatively higher overall cycle efficiency up to 41.5% is possible, though some of this may be lost if tighter environmental standards are imposed.

The simplified schematic of the reference plant with the thermodynamic conditions at the major process steps was shown previously in Figure 4-2. Each of the major components are described in the following paragraphs. Key parameters are summarized in Tables 4-2 and 4-3. For the purposes of discussion, the cycle is divided into the following seven categories:

- LBtu Fuel Plant
- Gas Cleanup System
- Gas Turbine System
- HRSG—Steam Turbine System
- Feedwater System
- Steam Extractions
- Generation

These categories are discussed in the next section.

Table 4-2. System Parameters Open Cycle Gas Turbine Combined—Air Cooled

FUEL	
LBtu Gas (wet basis)	HHV = 2959 Btu/lb, LHV = 2745 Btu/lb*
Composition By Weight	
S (as H_2S + COS)	0.05%
GASIFIER	
Type	Fixed Bed
Operating Pressure (psia)	263
Cleanup System	Alkazid + Claus for H_2S Removal
	COS Hydrolyzer and NH_3 Removal
PRIME CYCLE	
Gas Turbine	Air Cooled
Turbine inlet temp (^oF)	2400
Compressor pressure ratio	12:1
Working fluid	Combustion gas
Turbomachinery configuration	Axial-flow
Turbine exhaust (^oF)	Axial, 1183
HEAT EXCHANGER	
Heat Recovery Steam Generator	
Vapor generator pinch point	
ΔT (^oF)	18
Exit ΔT (^oF)	84
Gas side $\Delta p/p$	.05
Drum to throttle $\Delta p/p$	.11
Reheater $\Delta p/p$	.10
Economizer Δ p/p	.01
BOTTOMING CYCLE	
Steam Bottoming Cycle	
Throttle temp (^oF)	950
Throttle pressure (psi)	1800
Reheat temp (^oF)	950
Condensing pressure (in. Hga)	2.3
Feedwater temp (^oF)	259
HEAT REJECTION	
Wet Cooling towers	16 cells
Stack temperature (^oF)	312

* Data on "dry equivalent" not supplied for standard conditions.

Table 4-3. Summary of Design Parameters - Open Cycle Gas Turbine Combined Cycle with Low Btu Gasifier (Full Load Conditions)

ENVIRONMENTAL IMPACT	ECAS 579 MW	1250 MWe Plant
Coal Feed (lb/hr) ECAS/Example	480,240	1,004,968
S in Feed (lb/hr) 3.9/3.2	18.729	32,159
N in Feed (lb/hr) 1.0/.79	4,802	7,939
C in Feed (lb/hr) 59.6/61.49	286,223	617,955
Ash in Feed (lb/hr) 9.6/10.29	46,103	103,411
HHV (Btu/lb)	10,788	11,026
lb. dry gas at saturator exit / lb. carbon in Feed	4.5095	4.5093
lb. dry gas at saturator exit / lb. Coal Feed	2.6877	2.7728
Clean gas at saturator exit* (wet) (lb/hr)	1,527,840	3,279,793
Fuel gas consumed in gas cleanup (wet) (lb/hr)	8,640	18,653
Fuel gas combusted in turbines (wet) (lb/hr)	1,519,200	3,279,793
Gas turbine exhaust (lb/hr)	8,640	18,653
COS Hydrolysis Eff. (%)	100	100
NH_3 Removal Eff. (%)	96.46	97
NH_3 By-Product Production Total (lb/hr)	3,920	9,068
Alkazid Removal Eff. (%)	97.84	95
Claus Removal Eff. (%)	95.00	95
Sulfur By-Product Production (Elemental) (lb/hr)	17,830	29,917
Wellman-Lord Eff. (%)	98.50	90
Wet Scrubber Eff. (Process Gases) (%)	97.64	85
Heating Value of Fuel Gas (wet) (Btu/lb)	2,959	2,959

* 15.52% H_2O

Table 4-3. Summary of Design Parameters - Open Cycle Gas Turbine Combined Cycle with Low Btu Gasifier (Continued)

ENVIRONMENTAL IMPACT	ECAS 579 MW	1250 MWe Plant
Lime Requirement (lb/hr)	1,500	2,434
Sludge Disposal (lb/hr)**	1,550	6,076
SO_2 Emissions (lb/hr)***		
Turbine Gases	782	3,146
Wellman-Lord	78	316
Wet Scrubber	39	154
TOTAL	899	3,616
NO_2 Emissions (lb/hr)***		
Turbine Gases	819	743
Wet Scrubbers	17	13
TOTAL	836	756
SO_2 Emissions (lb/MBtu Gas)		
Turbine Gases	.17	.32
Wellman-Lord	.02	.03
Wet Scrubber	.01	.02
TOTAL	.20	.37
NO_2 Emissions (lb/MBtu Gas)		
Turbine Gases	.182	.077
Wet Scrubbers	.004	.003
TOTAL	.186	.080
# Gasifier Vessels (Operating/Standby)	12/14	2 x 13/16
Plant Heat Rate (Btu Coal/kWh)	8,948	8,865
Plant Efficiency (%)	38.14	38.50

** ECAS value likely in error or may be dry weight, this example uses relationship specified in ORNL O&M cost document of 10 tons sludge per 4 tons lime feed. (Sludge ≈ 50% water).

*** ECAS components do not derive from data specified in report—ECAS report seems to have many inconsistencies here. Total emissions based on 0.2 lb/MBtu gas with proportions roughly comparable to to those shown on Figure 4.6-17. (NO_x = .186 lb/MBtu)

3.2 LBTU FUEL PLANT

The advanced fixed bed gasifier, producing a LBtu fuel gas, has two major characteristics:

1. It handles more coal fines than state-of-the-art fixed bed gasifiers.
2. It allows maximum tar to recycle.

The ability to use more fines permits the use of conventional, low-cost coal crushing equipment. To ease the separation of coal fines, the incoming coal feed is first fired and then crushed to obtain 25 percent of the coal as fines. After fines separation, the crushed coal passes through a spray station where the coal moisture is restored to the original level and then fed to the coal hoppers. The separated fines are mixed with the recycled tar in a mixer; the mixture is extruded and fed to screw conveyor feeding to the gasifier vessel.

The gasifier walls in the oxidation zone are cooled by water in the circulating jacket. Water at 330°F is supplied to the jacket from the gas cleanup system; the circulating water is flashed in a drum. The vapor generated is introduced into the gasifier vessel as part of the steam required for gasification process. The gasifier process air is extracted from the main compressor; this air is saturated with water which serves as the remainder of the gasification process water requirement. A steam-driven booster compressor raises the pressure and delivers this air to the gasifier vessel.

The raw LBtu gas leaves the gasifier vessel at 865°F. This gas passes through a series of saturator/washer-cooler vessels (two vessels per gasifier vessel): the first vessel separates heavy tar from the raw gas, and the second vessel separates light tar oil, naphtha, and phenols. A major fraction of the heavy tar is recycled back to the gasifier vessel. It is either mixed with coal fines or directly injected into the vessel. Saturated raw gas leaving the second vessel at 307°F enters the gas cleanup system.

3.3 GAS CLEANUP SYSTEM

In order to meet the solid fuel emission standards, the hydrogen sulfide (H_2S) content of the raw gas must be reduced significantly. The Alkazid process selected here for this purpose requires that the gas be cooled to 100°F. The H_2S removed from the gas is converted to elemental sulfur in the Claus plant.

The cleanup system includes an incinerator which oxidizes the heavy tar blowdown, the lock-hopper vent gas, and the tail gas from the Claus plant. The thermal energy released through incineration is used to generate process steam and to heat process water. This internally generated process steam supplements the steam (at 65 psi) imported from the steam bottoming cycle, and meets the steam requirements of the Alkazid H_2S recovery unit.

The cleanup system requires a process water flow input; some of this water is heated to 330°F and is supplied as gasifier jacket cooling water. The cleanup system also has substantial heat rejection to the cooling tower, for which 21 x 10^6 lbs. of cooling water per hour is required.

The clean gas finally leaving the cleanup system is saturated at 275°F. The light tar oil, phenols, and naphtha removed from the raw gas stream earlier are added to the clean fuel gas. In order to avoid condensation in the fuel line, the gas is superheated to 300°F in a fuel-gas preheater before it is supplied to the combustor.

The composition of the low Btu gas is given in Table 4-4.

3.4 GAS TURBINE SYSTEM

This cycle employs eight air-cooled gas turbines, with a 12:1 compressor pressure ratio and a 2400°F firing temperature (that is, the temperature at the inlet of the first-stage rotor). Some of the compressor discharge air is used for turbine cooling. Part of this air is nonchargeable, that is, it enters the gas path before the first-stage rotor. The rest of the cooling air from the compressor discharge is chargeable. This chargeable air is cooled before injection into the turbine. Cooling air is also extracted from two intermediate extraction points in the compressor. The cooling air from the higher pressure extraction point is also cooled prior to injection in the turbine.

Table 4-4. Low Btu Fuel Gas Composition

Constituent	Weight
N_2	43.17
H_2O	15.52
CO_2	7.95
CO	27.24
H_2	1.13
CH_4	2.29
C_2H_4	0.22
C_2H_6	0.35
Oil, Tar, & Phenol	2.07*
NH_3	0.01
H_2S	0.05+
COS	Neg.

* May be recycled in gas cleanup
\+ Post cleanup

Since the fuel gas contains adequate moisture, additional steam injection in the combustor (for the purpose of NO_x suppression) is not required. Each of the gas turbine units produces a net electric power of 108.8 MWe and has an exhaust gas temperature of 1183°F.

3.5 HRSG-STEAM TURBINE SYSTEM

The heat recovery steam generator unit extracts thermal energy from the gas turbine exhaust flow stream and produces steam for use in a steam turbine system. One HRSG unit is provided for each gas turbine.

The HRSG unit consists of a horizontal reheater/superheater section followed by a vertical section comprising an evaporator, an economizer, and a drum. The combustion gas entering the HRSG unit at 1183°F is cooled down to 413°F at the exit of the economizer. This gas is further cooled to 334°F by using a low-pressure economizer that transfers the thermal energy from the gas steam to the feedwater heater train. This low-pressure economizer section is located above the high-pressure economizer section. The combustion gases pass through a silencer before entering a stack. A fraction of the stack gas (≈ 10 percent) is used to dry the coal in a coal dryer and is returned to the stack. The temperature of the gas discharging through the stack is 312°F.

The steam cycle conditions are selected to be 1800 psig and 950°F. The feedwater temperature is 259°F, and the condensing pressure is 2.3 in. Hga. One steam turbine serves each four HRSG units, with a net power output of 428 MWe from the two units.

3.6 FEEDWATER SYSTEM

Steam condensates from the main steam turbine and the booster turbine, along with the treated makeup water, are pumped to the deaerator tank by a condensate pump. Water from the deaerator tank is circulated through the low-pressure economizer loop. The economizer discharge is supplied to a flash tank at 30 psia; saturated vapor from the flash tank is condensed in the deaerator heater; and the liquid is fed back to the deaerator tank. The deaerator removes noncondensible gases from the feedwater. The energy input from the low-pressure economizer loop is sufficient to maintain the desired deaerator conditions, and no steam extraction from the steam turbine is required. The deaerator tank at 30 psia supplies the feedwater to the feedpump.

3.7 STEAM EXTRACTIONS

The cycle has three steam extractions from the steam turbine:

1. For the Booster Steam Turbine Drive: Steam from the cold reheat point (that is, after expansion through the high-pressure turbine) is supplied to the two steam turbines driving the booster compressors. The condensing conditions are taken at 2.3 in. Hga. Part of the condensate is sprayed into the air saturator, and the remaining is pumped back to the feedwater train.

2. For the Fuel-Gas Preheater: Steam at 82 psi is supplied to the heater to super heat the LBtu fuel gas.

3. For the Gas Cleanup System: The external process steam demand for the gas cleanup system is satisfied by extracting steam at 68 psi from the steam turbine and mixing it with the hot water discharged from the fuel-gas preheater.

3.8 GENERATION

The plant's thermodynamic cycles accomplish generation within two of its parts. Generation is done by the net output of the gas turbines and Rankine heat recovery (bottoming cycles). All generators operate synchronously at 60 Hz. They feed a common switchyard at the plant site. Generation capacity and internal (auxiliary) use are summarized as follows:

Total prime cycle (gas turbine) (8 units) output (MWe at 60 Hz)	884.1
Total bottoming cycle (steam turbine) (2 units) output (MWe at 60 Hz)	417.1
Total gross output (MWe at 60 Hz)	1301.2
Total auxiliary losses (MWe at 60 Hz)	51.2
Net power plant output (MWe at 60 Hz 500 kV)	1250.

3.9 FUELS USE AND LOGISTICS

This plant uses high sulfur coal (typically eastern high sulfur bituminous coal) to generate a net capacity of 1250 MWe with an assumed capacity factor of 70%. A detailed heat balance shows that 8865 Btu of pulverized coal is required to generate one kilowatt-hour of net output; this corresponds to a net plant efficiency of 38.5%. The coal characteristics chosen assume a higher heating value of 11,026 Btu/lb of coal on an as received basis. At full capacity, coal feed is required at a rate of 502 tons/hr. or 3.08 x 10^6 tons/year at 70% capacity factor. At this rate, an average of 8,434 tons of coal would be delivered to the site each day; as coal storage requirements are estimated at full capacity factor, a 3-day live storage stock pile would contain 25,301 tons of coal, and a 57 day reserve storage would contain 480,720 tons of coal.

The average storage density of utility coal in live storage is 960 tons/acre-ft and reserve storage density averages 1176 tons/acre-ft. Assuming 30 ft high active storage and 50 ft high reserve storage results in a site area of about 9 acres devoted to coal storage and handling.

4.0 ENVIRONMENTAL CHARACTERISTICS

4.1 OVERALL ENVIRONMENTAL IMPACT

Figure 4-3 depicts the major environmental impact of fossil fuel plants which arise from the impurities in the fuel and water used by the plant. The major impurities in the fuel are the sulfur and nitrogen compounds and incombustible ash. In the gasification step, almost all of the ash is separated from the coal, so it does not show up as a potential air pollutant. However, it represents a sizable solid waste disposal problem. Similarly, about 93% of the sulfur is removed from the process stream by the combined Alkazid-Claus process. This sulfur may be sold as an industrial by-product or disposed of in a landfill. Another 1.3% is disposed of in the scrubber sludge from the wet limestone scrubber. The remaining sulfur appears as SO_2 in the stack gas from the various plant flues and exhausts. NO_2 control is effected by removing most of the NH_3 from the fuel gas streams before combustion.

Water used for plant cooling also is a source of environmental pollution. As the water is evaporated, concentrations of dissolved solids increase. This brackish "blowdown" water must be specially handled, to avoid pollution of local water systems.

Plant siting must take all of these factors into account to select a location in compliance with all applicable emissions and land use criteria. Primary factors affecting the siting of a combined cycle plant are water availability and Federal, State and local emission regulations. The plant design used in this characterization satisfied the gas turbine and combined cycle plant emission standards for new sources. (EPA New Source Performance Standards-40 CFR Part 60.) Other considerations affect siting of the plant such as local impacts on achieving ambient quality standards or criteria for prevention of significant deterioration.

4.2 FUEL GAS CLEANUP SYSTEM - SULFUR

The cleanup system must remove enough sulfur as elemental sulfur so that the sum of the SO_2 emitted with incinerator flues and the SO_2 emitted with the power plant flues will be no greater than allowed by the EPA Standards. The COS formed in the gasifier and entering with the raw gas will be hydrolyzed to H_2S before entering the Alkazid plant. Virtually all the COS is hydrolyzed

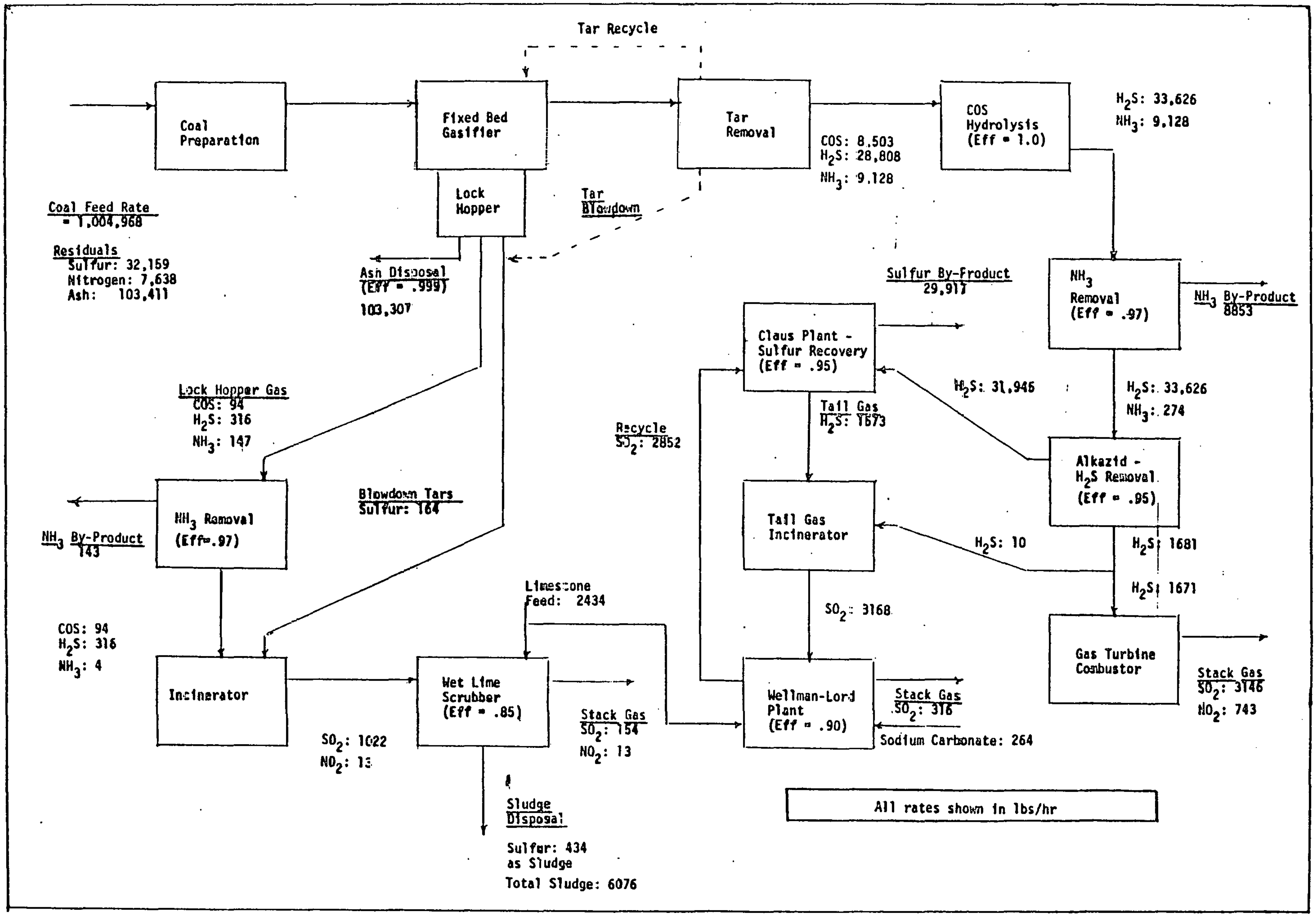

Figure 4-3. Environmental Residuals Summary for 1250 MWe Low Btu Gasifier Combined Cycle Plant

to H_2S for removal. The Alkazid plant removes H_2S from the product gas to a level which allows the limit to be met. Of the H_2S removed by the Alkazid plant, 5% will not be converted to elemental sulfur in the Claus plant. This 5% of the H_2S will be converted to SO_2 when the tail gas is incinerated. The tail gas is treated in the Wellman-Lord plant, which allows 90% of the sulfur to be recycled back to the Claus process. The Alkazid plant removes 95% of the H_2S entering the raw gas, thereby satisfying emissions standards. The cleaned gas contains 238 ppm by volume (dry) of H_2S. A separate cleanup system reduces the sulfur emissions from the lock-hopper gas. Only 5.6% of the total sulfur is emitted to the atmosphere as SO_2.

Alkazid is the trade name for a gas sweetening process using concentrated water solutions of salts of amino acids. The process which was developed in the 1930s in Germany, is now in the public domain. The sorbent is a solution of the potassium salt of diethyl glycine or dimethyl glycine. The amine group in the salt is basic and has a natural affinity for any gas that dissolves and forms an acid in water solution. H_2S forms acidic complexes in water so it is called acid gas, and forms a weak complex with the amine group in Alkazid.

About 95 % of the incoming H_2S must be removed in the cleanup system. Towers operating in parallel are needed to accommodate the large volume of gas flow. Gas enters the bottom of each tower and leaves through the top. Fresh clean sorbent is added at the top of each tower, and loaded sorbent is withdrawn from the bottom of each tower. The liquid and gas flow counter-current. During the absorption, both H_2S and CO_2 are absorbed. However, the affinity of the sorbent for H_2S is about 28 times as great as for CO_2.

The loaded sorbent from the absorption tower is regenerated by stripping out the H_2S and CO_2 with an ascending current of water vapor. The stripper operates at a high temperature and a low pressure so that the vapor pressure of the acid gases leaving the solution is higher than the partial pressure of the acid gases in the vapor phases. This ensures that the acid gases leave the liquid phase and enter the gas phase. The best performance conditions for an absorber are at low temperature and high pressure whereby the acid gases tend to leave the gas phase and enter the liquid phase. The conditions for operating a stripper are the opposite of those for an absorber.

The Claus plant converts H_2S in an acid gas into elemental sulfur. Claus plants are standard packaged systems. Usually, they operate at 90% efficiency. That is, 5% of the entering sulfur remains unconverted and leaves as H_2S and SO_2 in the tail gas. The tail gas is incinerated and scrubbed to remove most of this SO_2 before it is emitted to the atmosphere. Part of the SO_2 from the Wellman-Lord scrubber is recycled to the Claus plant. A third of the entering acid gas is incinerated with stoichiometric air to form SO_2. The hot gases are cooled in a waste heat recovery boiler so that when they are mixed with the acid gas that was bypassed, the temperature will be around 450°F (505 K). The mixed gases react with the reaction:

$$2\ H_2S + SO_2 \rightarrow 3\ S + 2\ H_2O.$$

However, only part of the H_2S reacts in this way in the mixing environment without catalyst. The gas is cooled to condense the sulfur vapor thus formed; then it is passed through three successive cycles of reheating, reaction over catalyst, and cooling to condense liquid sulfur.

4.3 CONTROL OF NO_x

Nitrous oxides are formed by combustion of ammonia, and to a limited extent by oxidation of N_2 gas diluent. To meet the emission standards, 0.34 lb of NO_2 may be emitted to the atmosphere per MBtu of gaseous fuel. In other words, 3% of NO_2 can be emitted and will indicate that NH_3 removal equipment is needed. The product and lock-hopper gas is washed to reduce its NH_3 content. The ammonia is removed for sale as a potential by-product. Attention must be paid to the design of the gas turbine combustion system to minimize the formation of NO_x by oxidation of atmospheric N_2.

4.4 CLEANUP OF PROCESS WATER SYSTEMS

In the cleanup system, foul water condenses from the gas during dewatering. A foul process water enters with oil and phenol from the gasifier washer-coolers. These foul waters contain dissolved H_2S, NH_3, CO_2, and phenols. The water separated from the oil and phenol is returned to the washer-coolers where some additional makeup water is located. This makeup water evaporates and enters the cleanup systems with the saturated gas. In both cleanup systems, some heat must be added to the makeup water before it is sent to the washer coolers.

4.5 LIQUID WASTE

Ammonia (NH_3) produced at the plant site would be stored in suitable tanks for regular removal by tank-car or by pipeline to potential users.

4.6 SOLID WASTE

Solid waste, mainly ash and other noncombustible products from the gasifier, is a major disposal problem. This is complicated by the potential presence of hazardous materials in the ash. Thus, special care must be taken in disposing of the ash in a suitable fashion, to minimize the environmental impact. Separate facilities would be required to dispose of scrubber sludge by ponding. Suitable means would have to be found to prevent the sludge from diffusing into the ground, probably by lining the disposal area with an impermeable layer.

The sulfur recovered from the Claus plant may also be treated as solid waste, if it cannot be marketed.

4.7 SPECIFIC DATA ON RESIDUALS

4.7.1 Air Emissions

These are the total emissions which determine the plants' compliance with the New Source Performance Standards for gas turbines. These may also limit plant siting under the criteria for the prevention of significant deterioration. Emissions are:

SO_2	:	43.4 tons/day
NO_x	:	9.1 tons/day
Particulates	:	3.0 tons/day

Gaseous emissions come both from the incinerator stack of the LBtu gas clean-up system and from the gas turbine combustion products discharged through the heat recovery steam generators. The values for emissions given above are for nominal (1250 MWe) plant operation.

4.7.2 Liquid Effluents

Primary cooling water and blowdown = 2.50×10^6 gal/day.

4.7.3 Solid Wastes

Materials recovered from the process stream are:

Ash	:	1240 tons/day
Sulfur	:	359 tons/day
Ammonia	:	108 tons/day
Sludge	:	51 tons/day (tail gas cleanup)

The total waste heat dissipated by the palnt to the atmosphere is as follows:

Cooling Towers	:	3.44×10^9 Btu/hr
Stack	:	2.58×10^9 Btu/hr
TOTAL		6.02×10^9 Btu/hr

4.7.4 Land Use

The plant requires a considerable amount of land for plant facilities and for waste disposal. The basic land requirements for this plant are as follows:

Plant Area	:	132 acres
Waste Disposal over a 30-Year Lifetime	:	214 acres
TOTAL		346 acres

The actual plant site would be about 500 acres to provide room for expansion or changing needs over the plant's lifetime.

4.7.5 Water Consumption

Estimated value for water consumption is given in the table below:

Water, total (10^6 gal/day)	12.48
Consumption:	
Cooling tower evaporation	7.62
Steam system makeup	0.06
Gasifier process	0.81
Gas cleanup system	1.26
NO_x suppression	0.00
"Hotel" usage	0.30
Blowdown treated waste:	
Cooling tower blowdown	2.40
Boiler drum blowdown	0.03

The total water demand of 0.416 gal/kWh is based on the following assumptions.

- Cooling water evaporation and drift losses amount to 102 gal/MBtu of heat rejected, and the blowdown losses are estimated to be 32 gal/MBtu. The combined water loss from these two sources alone is 80% of total plant demand.
- Gasifier process water demand is in the form of water spray in the course coal train and water injection in the air blast; the latter is derived from the booster compressor drive turbine exhaust steam condensate and thus extracted from the steam cycle.
- Gas cleanup system water demand consists of process steam extracted from the steam cycle and process water flows. A small fraction of the consumed water leaves the cleanup system in the form of process blowdown.
- "Hotel" usage, taken at 3% of total water consumption, represents general plant use.

Key residuals are summarized in Table 4-5.

Table 4-5. Summary of Flow of Major Residual Materials for Environmental Control System

MATERIALS	TONS/YEAR
INPUTS	
Limestone	7463
Sodium Carbonate	811
Anti Oxidant	14
Wellman-Lord Catalyst	0.51
OUTPUTS	
Ash (from gasifier)	317,060
Elemental Sulfur	91,725
Sulfur Sludge	18,629
Ammonia (By-Product)	27,594

5.0 CONSTRUCTION AND OPERATION CHARACTERISTICS

5.1 PERSONNEL REQUIREMENTS

The normal construction period for a large coal-fired electric generation facility of the type characterized here would take a total of seven years. This includes a fairly low-level-of-effort period of two years for site selection, design, and preparation, and a five year period of actual on-site construction. During the on-site construction period, an estimated 8.1 million man-hours of direct craft labor would be required.

The direct craft labor employment figures do not include various inhouse utility and consultant man-hours which are considered indirect labor requirements by the utility for capital costing purposes. The magnitude of these indirect labor requirements, however, is somewhat less than the direct craft requirements.

Since this technology is new, and until regular routines are developed, additional time may be required for construction, testing, and start-up. Detailed labor breakdowns are not available for this technology.

Operating personnel requirements for this plant can only be roughly estimated from similar requirements for conventional plants. An estimated personnel requirement is shown in Table 4-6. Detailed breakdowns of their activities would be similar to other coal-fired systems. From time to time, additional maintenance staff would be required to complete major scheduled or unscheduled emergency repairs on the turbine system, boiler, environmental control system, or other major plant components.

5.2 OPERATING STATISTICS AND ANNUAL GENERATION

Historical statistics on large coal-fired electric generation facilities of this type indicate that the overall plant capacity factor would be in the neighborhood of 70%, which has been used throughout this characterization. In other words, the plant would produce 70% of the maximum possible kilowatt-hours it could generate if it were operated continuously at full capacity.

Table 4-6. Direct Labor Summary for Operation of Reference 1250 MW Coal Gasification Facility/Combined Cycle (2 Units)*

OPERATING PERSONNEL	NUMBER OF PERSONNEL	THOUSAND MAN-HOURS/ YEAR
Plant Managers Office		
Manager	1	2
Assistant	2	4
Environmental Control	1	2
Public Relations	1	2
Training	1	2
Safety	1	2
Administrative Services	14	28
Health Services	1	2
Security	7	14
SUBTOTAL	29	58
Operations		
Supervision	3	6
Shifts	50	100
Fuels and Materials Handling	12	24
Waste Systems	30	60
SUBTOTAL	95	190
Maintenance		
Supervision	8	16
Crafts	115	230
Peak Maintenance Annualized†	66	132
SUBTOTAL	189	378
Technical and Engineering		
Waste	2	4
Radiochemical	2	4
Instrumentation & Control	2	4
Performance, Reports and Technicians	17	34
SUBTOTAL	23	46
TOTAL	336	672

* Adapted from Operating Staff requirements for 2 unit coal facilities, 400 MWe - 700 MWe with FGD

† 572 persons for 6 weeks = 3,432 person weeks ÷ 52 weeks/yr = 66 persons annualized

Numerous parameters combine to produce this factor. Namely, these include plant down-time for scheduled maintenance, plant forced outage rate due to unexpected component failure, and the customer load profile (including inter-utility sales of electricity). The first two factors combine to determine plant availability, while the inclusion of customer demand results in the plant capacity factor.

Typically, a large coal-fired station, such as the type characterized here, would be placed early in the utility's loading order. Thus, it would hardly be affected by the customer's demand since it would serve to satisfy part of the minimum customer load. However, a factor of 0.97 has been applied to the calculated plant availability to simulate a small reduction in plant operation.

Scheduled maintenance for large coal facilities with flue gas desulfurization systems vary between 4 to 8 weeks/year, and forced outage rates range from 10 to 15%. Here, the larger or more conservative values have been selected for the reference facility. Thus, plant availability is determined by:

$$\text{Plant Availability} = \left(\frac{52-8}{52}\right) \times (1-0.15) \times 100\% = 72\%$$

Adjusting for customer demand reduction results in:

$$\text{Capacity Factor} = (72\%)\ (.97) = 70\%$$

At this capacity factor, the reference 1250 MWe high-sulfur coal facility would generate 7.665×10^9 kilowatt-hours/year. However, actual operating experience is lacking with combined cycle systems. For new plants, capacity factors are likely to be lower, until plant reliability is improved and operating practices consolidated.

5.3 GASIFIER REQUIREMENTS

The plant has to be designed with a sufficient number of gasifiers so low Btu-gas and electrical energy production can be maintained, even during individual or multiple outages of gasifier modules. This system is designed with additional gasifiers that serve as backups. This raises the overall system availability. The methodology and design calculations are summarized in Table 4-7.

Table 4-7. Summary of Gasifier Availability Analysis

$$\text{Gasifier Availability} = \sum_{x=1}^{x=m} P(x)\,\frac{x}{m}$$

where $P(x)$ = probability x gasifiers are operating

m = total gasifiers needed for plant operation

$$P(x) = \binom{n}{x} p^{x} (1-p)^{n-x}$$

where n = the total number of units

p = probability any one unit is working = $1-q$

q = outage rate

Design Example -

Operating units	(m)	=	13
Total units	(n)	=	16
Outage rate	(q)	=	0.20
Availability		=	94.4%

6.0 COST CHARACTERIZATION (CG/CC)

Capital cost estimates for the 1250 MWe reference coal gasification combined cycle generation facility have been derived primarily from cost data presented in the ECAS report, which also served as the basis for the technological characterization developed in the previous sections. The ECAS report estimates direct capital costs (in 1975 dollars) and labor requirements for a 579 MWe single unit facility which is similar in design to the reference system. The ECAS study, however, assumed the use of coal feed with somewhat different properties than is assumed here. In addition, the study assumed more stringent environmental controls that are required on a facility of this type. The procedures which are used to adapt the ECAS direct cost estimates reflect the reference coal gasification combined cycle facility design parameters and are discussed in the following section.

To ensure consistency with the cost estimates for the other technologies, indirect costs were derived from data on a 630 MWe coal gasification. This data was presented in the Energy Economic Data Base (EEDB). Before selecting these costs, the data costs and the labor requirements for an alternative ECAS coal gasification combined cycle facility were compared to those costs of the similar EEDB plant. Both plants were designed to meet the solid fuels emission standards. After correcting the differences in the dollar value of the estimates and plant capacities, these costs and labor requirements were found to be very similar.* This similarity thus supports the use of the EEDB indirect costs for the reference system.

6.1 DIRECT CAPITAL COSTS

The ECAS direct capital costs are estimated in 1975 dollars for a single unit (579 MWe coal gasification combined cycle facility). The costs have been appropriately adjusted to reflect major design and performance characteristics assumed for the reference facility which is composed of two 625 MWe units on one plant site. In particular, the design and performance modifications

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* Actually, substantial differences in costs were displayed for some individual accounts due primarily to different gasifier vessel designs and other factors. The "bottom line" costs, however, differed by only a few percent and labor requirements were nearly identical.

assumed for the reference system, that measurably affect the facility's direct capital costs, are summarized below:

- Feed coal characteristics used in the ECAS study (10788 Btu/lb, 3.9% sulfur, 9.6% ash and 59.6% carbon) have been modified to be consistent with the coal characteristics assumed in the conventional coal combustion reference system (11026 Btu/lb, 3.2% sulfur, 10.29% ash and 61.49% carbon). This modification results in a 3% decrease in coal feed throughput and a 5% increase in ash throughput to produce the same quantity of low Btu gas.

- Air emission standards used in the ECAS study assume SO_2 and NO_x limits of 0.2 $lb/10^6$ Btu of gas fired. Recent regulations promulgated by the EPA specify that gas turbine emission standards apply to a facility of this type. These emission limits are 150 ppm of SO_2 and 75 ppm of NO_x by volume in the turbine exhaust gas stream at 15% oxygen. These standards are approximately equivalent to .47 $lb/10^6$ Btu of gas fired for SO_2 and .34 $lb/10^6$ of gas for NO_x. The current standards are easily met by the gas cleanup equipment installed on the reference facility. Thus, the only modification made to the ECAS design was to reduce the cleanup equipment installed on the reference facility. Thus, the only modification made to the ECAS design was to reduce the cleanup equipment collection efficiencies ranging from 95 to 98.5% to more achievable values ranging from 90 to 95%. These efficiencies are consistent with the assumptions related to the conventional coal facility. The result is emission levels below the applicable standard. The combined effect of this modification, coupled with the difference in coal characteristics, is to reduce the residual's loading on the gas cleanup equipment by approximately 20% for the same quantity of low Btu gas.

- Overall unit capacity was increased from 579 MWe assumed in the ECAS study to 625 MWe, a 7.9% increase in major plant flows and generation output. This modification resulted in the requirement of an additional operating gasifier (13 rather than 12) to achieve full capacity output while maintaining the unit gasifier vessel ash throughput within the design range specified in the ECAS study. A parametric analysis of the gasifier module reliability indicated that an additional standby gasifier would substantially decrease the module forced outage rate. Thus, three rather than two standby vessels have been assumed. In total, 16 vessels are assumed for each unit in the reference system (32 vessels in the two-unit plant) as compared to 14 vessels per unit in the ECAS design.

- The reference system capacity of 1250 MWe is assumed to be achieved by a two unit plant, each unit generating 625 MWe at full capacity. Although design limitations would require major equipment pieces to be independent, such systems as site structures and improvements, some fuel and residuals handling equipment can be shared by the two units. As a result, a detailed cost estimate indicates a 9% cost savings on the second unit.

Base direct capital costs include the cost of all materials, components, equipment, structures, and associated craft labor necessary to construct the reference facility at the plant site. Delivered costs for materials and equipment are used. Base indirect costs include site temporary construction facilities, payroll insurance and taxes, and other home and field office expenses. Specifically excluded from the base construction cost estimate are several items that are sensitive to the particular policies and preferences of the individual utility and to the specific plant site and prevailing economic factors being considered. These exclusions are identified in the following list of items:

- Owner's Costs - Consultants, Site Selection, etc.
- Federal, State and Local fees, Permits and Taxes
- Interest on capital Construction Funds
- Price Escalation During Construction
- Contingency Funds
- Owner's Discretionary Items - Switchyard and Transmission Costs, Waste Disposal Costs, Spare Parts, and Initial Fuel Supplies

The methodology and procedure applied to estimate the direct capital costs for the 1250 MWe reference coal gasification combined cycle system was to review the detailed cost estimates made in the ECAS report for the 579 MWe design and, where appropriate, adjust the costs using a capacity or loading ratio estimating relationship. This technique, which is generally accepted by the electric power generation industry for making cost estimate modifications of similar systems or subsystems, uses the following equation to adjust component capital costs to different levels of capacity or loading:

$$\text{Cost or Component B} = \text{Cost of Component A} \times \left(\frac{\text{Capacity of B}}{\text{Capacity of A}}\right)^{\alpha}$$

where components A and B are of similar design, differing only in size, capacity, or loading, and where the exponent (α) depends on the type of system or component being considered. The exponent values used in estimating the costs of the coal gasification combined cycle reference system components are similar to those used in estimating the costs for the reference coal combustion facility. Due to the unique nature of the ECAS code of accounts, however, it was necessary to apply the cost estimating exponents to individual equipment items to ensure consistency with other technology cost estimates derived from the Energy Economic Data Base code of accounts. Thus, it was first necessary to identify the applicable EEDB coal system account for each ECAS equipment item and then assign the appropriate cost estimating exponent. Where no direct parallel of equipment type existed, basic design similarities were taken into consideration (e.g., tank, vessel, pump, turbine) before assigning an appropriate cost estimating exponent. Details of this and results of the following procedural steps are shown in the Appendix. Table 4-8 summarizes the original ECAS 579 MWe facility costs corrected to January 1, 1978 dollars and also shows the final direct capital cost estimates for the two unit reference 1250 MWe coal gasification combined cycle facility.

As explained further in the Appendix, the reference system direct capital costs were derived by application of the following procedural steps:

- A detailed equipment and cost list for the original ECAS 579 MWe plant using Illinois No. 6 coal (10788 Btu/lb, 3.9% sulfur, 9.6% ash, and 59.6% carbon) was compiled and appropriate cost estimating exponents consistent with the EEDB conventional coal system were assigned as indicated above.

- Using these cost estimating exponents, costs were modified to reflect: (1) the use of the Eastern Interior coal used in the conventional coal characterization (11,026 Btu/lb, 3.2% sulfur, 10.29% ash, 61.49% carbon) and (2) the decrease in loadings and collection efficiencies on pollution control equipment. The latter results from the different coal and applicable emission standards not enacted prior to the ECAS design. No modification was made to the system's gas production rate or generation capacity at this step.

- After correcting for coal characteristics and environmental regulations, the system was sized to a net output of 625 MWe. Two additional gasifier vessels were required at this step (+ 1 operating, + 1 standby, for a total of 16) to meet the ash throughput design limitation for each vessel and to ensure reliable operation. Since no modification was made to the vessel itself, these additional vessels were not costed using an exponent technique, but rather were added at their given unit costs. A separate account lists additional piping.

Table 4-8. Estimated Direct Capital Costs for Two Unit 1250 MWe Reference Coal Gasification Combined Cycle Facility (January 1, 1978 Dollars)

Account[a]	Description[a]	579 MWe ECAS DESIGN COST ($1000)	1250 MWe Reference Design Costs ($1000)		
			Unit 1	Unit 2	Total
20	Land and Land Rights	(b)	1,120[c]	1,120[c]	2,240[c]
21	Structures and Improvements	13,138	13,344	12,011	25,355
22	Coal Handling, Gasification, Cleanup	88,960	89,789	74,343	164,132
23	Prime (Gas Turbine) Cycle Equipment	37,016	37,016	37,016	74,032
24	Bottom (Steam Turbine) Cycle Equipment	29,180	30,867	30,867	61,734
25	Electric Plant Equipment	15,234	15,469	15,469	30,938
	TOTAL DIRECT EQUIPMENT	183,528	187,605	170,826	358,431
	SITE LABOR COSTS	93,660	93,660	85,283	178,943
	TOTAL DIRECT BASE CONSTRUCTION COSTS	277,188	281,265	256,109	537,374

(a) Miscellaneous equipment and condenser heat rejection system costs included in accounts 21, 22, and 23.

(b) Land costs not specified, ECAS assumed approximately 65 acre site.

(c) Assumes 500 acres at 4480 $/acre assigned equally to each unit.

- Estimates were then made on a component by component basis of the incremental cost of adding a second 625 MWe unit on the same site, sharing appropriate facilities. In some cases, (e.g., coal handling equipment) that portion of the equipment cost assignable directly to the individual unit's gasification or power production module was not considered as shared equipment, while the coal yard equipment or other plant structures were considered shared. The applicable relationship for the incremental second unit cost for independent and shared facilities are given by the following when identical capacities or loadings are required for each unit:

  Independent Equipment: $U_2 = U_1$

  Shared Equipment: $U_2 = (2^{\alpha} - 1)\, U_1$

  where, U_1 = Unit 1 cost

  U_2 = Unit 2 incremental Cost

  α = applicable cost estimating exponent

  Land costs were divided equally among the two units.

- Each of the resultant costs was then escalated to January 1, 1978 dollars from their original estimate in mid-1975 dollars by applying the corresponding GNP price deflator index ratio of 1.1365.

- Craft labor requirements for Unit 1 were taken to be identical to those associated with the original 579 MWe ECAS design which were also the same as those for the 630 MWe EEDB design, 7×10^6 man-hours. Craft labor costs for Unit 2 were taken to be proportional to the equipment and materials costs which result from the use of shared facilities and site labor learning associated with construction of the previous identical unit. Labor costs were taken to be consistent with the average labor cost estimated in the EEDB, or $13.38/hour. The indirect labor cost account indicates indirect labor costs.

6.2 INDIRECT CAPITAL COSTS

To ensure consistency across technologies, the indirect capital construction costs associated with reference coal gasification combined cycle facility were derived from the indirect costs associated with the combined cycle facility used in the Energy Economic Data Base. Indirect capital costs associated with the construction of large electric generation facilities are relatively insensitive to the range of unit capacities considered here. Therefore, the indirect capital costs for the first unit of the reference system coal gasification combined cycle facility are taken to be identical to the corresponding EEDB indirect costs. As various cost reductions are achievable when constructing identically designed units in a continuous operation at the same plant site, the indirect costs associated with the second unit are estimated to be proportional to the ratio of direct construction costs. Thus, indirect capital costs (summarized in Table 4-9) total $132,717,000.

Table 4-9. Estimated Indirect Capital Costs for 1250 MWe Coal Gasification Combined Cycle Reference System (January 1, 1978 Dollars)

ACCOUNT	DESCRIPTION	Reference Design Costs ($1000)		
		Unit 1	Unit 2	TOTAL
91	Construction Services	42,205	38,430	80,635
92	Home Office Engineering and Services	15,355	13,982	29,337
93	Field Office Engineering and Services	11,905	10,840	22,745
	TOTAL INDIRECT COSTS	69,465	63,252	132,717

6.3 OPERATION AND MAINTENANCE COSTS

Annual operation and maintenance (O&M) costs for the 1250 MWe reference coal gasification combined cycle facility have been estimated, based on cost estimating relationships in a recent Oak Ridge National Laboratory (ORNL) document entitled, "A Procedure for Estimating Non-Fuel Operation and Maintenance Costs for Large Steam Electric Power Plants," and on data available in the Energy Economic Data Base. In general, the O&M cost components used here have been adapted from cost estimates of large, conventional coal combustion facilities. As was previously the case with the conventional coal reference system, the O&M costs have been supplemented with EPA data on Wellman-Lord flue gas desulfurization O&M costs.

Generally, O&M costs consist of six cost categories and may be either fixed costs, not dependent on annual generation, or variable costs which are proportional to generation level. The six cost categories considered here include: plant staffing, maintenance materials, plant supplies and expenses, environmental controls, interim replacements, and administrative and general expenses.

Plant staffing costs are based on an estimated 336 person plant staff described earlier and assumes an average cost of $22,000 per person per year, or about $11/man-hour. Maintenance materials costs are assumed to follow the same relationship as coal plant costs averaging 82% of the maintenance staff costs (189 persons) for facilities with flue gas desulfurization; 62% being fixed expenses and 20% representing a maximum level variable expense at a plant capacity factor of 80%. Fixed and variable supplies and contract expenses are difficult to estimate because there is little data available on coal gasification combined cycle facilities. Expenses can be anticipated to be somewhat higher than a conventional coal plant due to the added system complexity. For this reason, fixed and variable supply and expense costs for the reference coal gasification combined cycle facility are estimated to be 60% higher than the corresponding costs of a conventional coal generation system. Thus, the fixed supplies and expenses are estimated .08 mills/kWh. Administrative, overhead, and utility home office general expenses associated with the reference facility are estimated to be 10% of the staff costs and fixed components of the materials, supplies, and expenses costs.

Operations and maintenance costs for environmental controls are based primarily on the ash, elemental sulfur, dry sodium sulfite/sulfate disposal costs of $4/ton for remote site disposal. Disposal costs for the wet lime scrubber sludge is estimated at $10/ton. A land area of 7.1 acres per year at $4,480 per acre has also been included in the environmental controls O&M cost estimate. Feed materials, such as lime, sodium carbonate, catalyst and an antioxidant required to operate the environmental control systems are also included as part of this cost estimate.

Annual costs for interim replacements of major capital items have been added to the O&M cost estimates. These were conservatively estimated to be 30% of the direct and indirect capital costs for interim replacements over the total plant capital costs (0.53% of total plant cost), and are charged to O&M each year.

Table 4-10 details the annual O&M costs estimated for the reference coal gasification combined cycle system. At the 70% capacity factor assumed for this system, annual O&M costs total $20.66 million or 2.70 mills/kWh; 2.22 mills/kWh are fixed costs, while 0.48 mills/kWh are variable with plant generation.

Table 4-10. Annual Operation and Maintenance Costs--1250 MWe Reference Coal Gasification Combined Cycle Facility at 70% Capacity Factor

O&M Account	COST ESTIMATING RELATIONSHIP	$1000/yr
Plant Staff	336 persons @ $22,000/yr (Fixed Cost)	7,392
Maintenance Materials	Fixed: 189 persons x $22,000/yr x .62	2,578
	Variable: 189 persons x $22,000/yr x .20 x $\left(\frac{.70}{.80}\right)$	728
Supplies & Expenses	Fixed: $1,400,000/yr (1.60)	2,240
	Variable: $\frac{(.08 \text{ mills/kWh})(1{,}250{,}000 \text{ kW})(8760 \text{ hr/yr})(.070)}{1000 \text{ mills/\$}}$	613
Environmental Control	Fixed: Included in Maintenance Materials, Supplies and Expenses	-
	Variable:	
	Lime Supply: 7,463 T/yr @ $42/T	313
	Sodium Carbonate Supply: 811 T/yr @ $78/T	63
	Antioxidant Supply: 811 T/yr @ 5,500 $/T	77
	Catalyst Supply:	1
	Ash Disposal (Dry): 317,060 T/yr @ $4/T	1,268
	Sulfur Disposal (Dry): 91,725 T/yr @ $4/T	367
	Sodium Sulfate/Sulfate Disposal (Dry): 835 T/yr @ $4/T	3
	Sludge Disposal (wet): 18,629 T/yr @ $10/T	186
	Disposal Site: 7.1 acres/yr @ $4,480 $/acre	32
Interim Replacements	Sinking fund accrual of 30% of indirect and indirect capital costs @ 30 yrs and 4% real interest 0.0178 (.30) (670,091,000)	3,578
Administrative & General	10% of staff, Fixed Materials, and Fixed Supply and Expenses	1,221
	TOTAL ANNUAL O&M COSTS	20,660

At 70% Capacity Factor

Fixed O&M Costs: $\frac{(17{,}009{,}000 \text{ \$/yr})(1000 \text{ mills/\$})}{(1{,}250{,}000 \text{ kW})(8760)(.7)} = 2.22 \text{ mills/kWh}$

Variable O&M Costs: $\frac{(3{,}651{,}000 \text{ \$/yr})(1000 \text{ mills/\$})}{(1{,}250{,}000 \text{ kW})(8760)(.7)} = .48 \text{ mills/kWh}$

2.70 mills/kWh

These costs compare with 2.69 mills/kWh for the conventional coal generation facility which is 1.66 mills/kWh fixed O&M costs and 1.03 mills/kWh variable costs at the 70% capacity factor.

7.0 THE COAL FUEL CYCLE DESCRIPTION

This section summarizes the mining and supply of coal to various types of coal burning plants. The actual amount of coal delivered will depend on the plant's heat rate.

The base case considered is a mine in the Eastern coal region. The coal cycle flow diagram is presented in Figure 4-4 based on a requirement for 1000 tons of coal delivered.

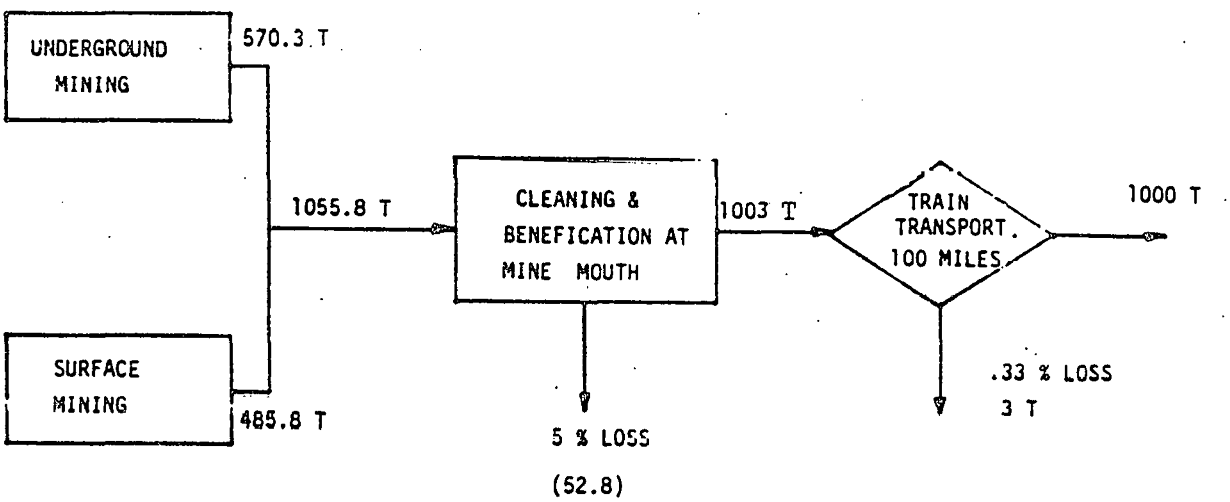

Figure 4-4. Coal Mining Cycle Summary

Each of the four stages involves processing and handling of the coal in different ways. The result is a series of diverse environmental impacts discussed in the following sections.

7.1 AIR EMISSIONS

7.1.1 Mining

Surface mining produces the following air pollution effects:

- Particulate emissions occur as a result of blasting, digging, and road usage. The emissions from blasting and digging are not controllable. Water spraying and other dust control techniques at transfer points on roadways can reduce particulate emissions by about 80 percent.

- Other emissions occur on an intermittent basis (NO_x from blasting) and continually (SO_x, NO_x, and CO) from the operation of diesel equipment. In large mining operations, the major excavating equipment is normally electrically driven so there are no direct equipment-related emissions.

Underground mining produces the following air pollution effects:

- Particulate emissions occur as a result of conventional mining (drill, load, and blast on an intermittent basis), and on an uninterrupted basis from the use of the continuous miner (the rotating drum cutters). Since mine health and safety laws require the air in the work areas to have particulate concentrations below 2 mg/m^3, most particulates are dumped into the ventilation system where the majority drop out in the circuitous path that the exhausted air follows. There is evidence (i.e., snow at the ventilation exhaust exits of mines) that some particulates escape to the atmosphere.

- Other emissions occur on an intermittent basis if conventional mining is utilized, e.g., NO_x from blasting. Otherwise, no direct emissions occur since underground coal mining equipment is normally electrically driven.

Air emission factors for surface mining are given in Table 4-11. Air emissions for underground mining are negligible.

7.1.2 Preparation

Improved dust control in mines has resulted in wetter run-of-mine (ROM) coals; subsequently less fugitive particulate emissions during handling operations prior to and during coal cleaning. However, there is no Federal regulation to control the emission source of fugitive dust from coal storage piles. In addition, refuse disposal piles may contribute fugitive dust as well as smoke, SO_x, NO_x, H_2S, and CO during burning that follows spontaneous combustion.

Thermal drying processes are used to dry the cleaned coal and make it suitable for transportation and combustion. The EPA's New Source Performance Standards (NSPS) for coal preparation plants regulates the discharge of particulate materials from thermal dryers to 0.031 grains per dry standard cubic foot. This further limits the amount of particulate emissions contributed by the preparation stage of the coal fuel cycle. Nevertheless, thermal dryers still contribute SO_x, NO_x, HC, and CO.

Table 4-11. Coal Mining Air Emissions Factors for Surface Mining[a]

POLLUTANT	TONS/DAY[b]
<u>Particulates</u>	
Uncontrolled and	0.01
Controlled	0.01
<u>Sulfur Oxides</u>	
Uncontrolled and Controlled	0.02
<u>Nitrogen Oxides</u>	
Uncontrolled and Controlled	0.28
<u>Carbon Monoxide</u>	
Uncontrolled and Controlled	0.18
<u>Hydrocarbons</u>	
Uncontrolled and Controlled	0.028
<u>Aldehydes</u>	
Uncontrolled and Controlled	0.00

(a) All surface coal is assumed to be moved by truck within the mine itself. No control techniques are assumed to be used to control fugitive dust.

(b) At nominal (1250 MWe) power plant operation.

NOTE: Air emissions from underground mining are negligible.

A summary of emissions from the coal preparation process is given in Table 4-12.

Table 4-12. Coal Preparation Air Emission Factors

TYPE OF POLLUTANTS	Utility Coal Cleaning		
	Gross Tons/day	Net[a] Tons/day[c]	Removal[b] Efficiency Percent
Particulates			
Base (1971)	25.63	8.04	68.6
Intermediate (1975)	25.63	3.00	88.3
Controlled	25.13	0.25	99.0
SO_x			
Base (1971)	0.75	0.75	0
Intermediate (1975)	0.75	0.75	0
Controlled	0.02	0.0	90.0
NO_x			
Base (1971)	0.41	0.41	0
Intermediate (1975)	0.41	0.41	0
Controlled	0.17	0.17	0
HC			
Base (1971)	0.31	0.31	0
Intermediate (1975)	0.31	0.31	0
Controlled	0.06	0.06	0
CO			
Base (1971)	1.53	1.53	0
Intermediate (1975)	1.53	1.53	0
Controlled	0.05	.05	0

(a) Net refers to emissions subject to environmental controls.

(b) Composite over the entire cleaning process. Note that gross coefficients decline over time because of reclamation of refuse banks.

(c) For nominal (1250 MWe) power plant operation.

7.1.3 Transportation

Each transportation mode has its own characteristic significant contribution to air quality degradation. Trucks produce the greatest air pollution/ton mile within a given distance, whereas closed pipeline systems produce only a small amount of direct emissions. Trucks however, account for only a small portion (10.7%) of the total ton-mile. In the example case, coal is assumed to be transported by train.

The air emissions for coal transportation for 100 miles are summarized in Table 4-13.

Table 4-13. Coal Transportation Air Emission Factors (Tons/Day)*

POLLUTANT	TRANSPORTATION TYPE			
	Unit Train	Mixed Train	River Barge	Truck
Particulates	2.07	3.95	1.95	56.
Sulfur Dioxide	0.38	0.30	0.08	0.31
Nitrogen Oxides	0.42	0.35	0.08	4.
Carbon Monoxide	0.41	0.32	0.06	2.55
Hydrocarbons	0.29	0.23	0.05	0.41
Aldehydes	0.06	0.05	0.00	0.07

* For nominal 1250 MWe plant operation.

7.2 LIQUID EFFLUENTS

7.2.1 Mining

The primary contribution to liquid effluent is acid mine drainage. A description of waste water effluent for Federal Region 5 is given in Table 4-14.

Table 4-14. Coal Mining Wastewater Effluents (Tons/day) *

POLLUTANT	SURFACE MINING	UNDERGROUND MINING
Total Iron	0.43	0.42
Suspended Iron	0.02	0.10
Dissolved Iron	0.42	0.31
Manganese	0.37	0.01
Aluminum	0.58	0.05
Zinc	0.01	0.00
Nickel	0.00	0.00
Total Dissolved Solids	32.93	5.65
Total Suspended Solids	4.45	0.27
Hardness	15.77	1.45
Sulfate	14.94	2.82
Ammonia	0.05	0.01
Strontium	-	0.0
Chloride	-	0.12
Fluoride	-	0.0

* For nominal (1250 MWe) power plant operation

7.2.2 Preparation

Currently, many coal preparation plants are operating with a closed water circuit and, as a result, normally discharge little or no process water. Further, drainage from coal storage piles and refuse areas can be collected and treated, thereby reducing the aquatic loadings from coal preparation plants. The characteristics of liquid effluents from coal preparation are described in Table 4-15 for refuse pile runoff. In each case, the net discharge is essentially zero.

Table 4-15. Coal Cleaning Wastewater Effluents Refuse Pile Run-Off*(Tons/day)(†)

WASTEWATER EFFLUENTS	Gross-Untreated Process Water Refuse Pile Run-off	Net(*) Discharge	Removal(††) Efficiency
Total Iron	2.99	0.00	99.9
Suspended Iron	2.97	0.00	99.9
Dissolved Iron	0.02	0	98.3
Manganese	0.07	0.00	95.4
Aluminum	0.28	0	100
Zinc	0.01	0	100
Nickel	0.0	0	100
Total Dissolved Solids	37.65	0	100
Total Suspended Solids	1648.05	0.02	99.9
Hardness	40.46	0	100
Sulfates	26.38	0	100
Ammonia	0.05	0	100

(*) These residuals pertain only to the refuse pile run-off, since the cleaning plant itself is assumed to employ closed water circuits to meet zero discharge.

(†) For nominal (1250 MWe) power plant operation

(††) On Refuse Pile Run-Off, using Best Available Technology

7.2.3 Transportation

The primary liquid effluents in transportation of coal will come from coal slurry through pipelines. However, in the baseline case (1250 MWe plant) the coal is assumed to be transported by train from an Eastern coal region mine to a power plant located 100 miles away. Under these assumptions, negligible effluents result.

7.3 SOLID WASTE

7.3.1 Mining

Table 4-16 lists the estimates of solid waste from mining operations. For surface (strip) mining, this waste is primarily an overburden from initial excavation. For underground mining, the primary contributor to solid waste is the residual from treating mine water.

Table 4-16. Mining Solid Waste Effluents

TOTAL SOLID WASTES	TONS/DAY OUTPUT*
Underground Mining	
1971 & 1975	256
1985 (projected)	356
Surface Mining	
1971 & 1975	294
1985 (projected)	460

* Supporting a 1250 MWe power plant

7.3.2 Transportation

No significant solid waste.

7.3.3 Preparation

Solid waste disposal is expensive and complex because the wastes can be hazardous and/or toxic. Additional treatment is likely to be a requirement of the pending regulations, since coal preparation solid wastes may be considered hazardous. A summary of solid wastes is presented in Table 4-17.

Table 4-17. Coal Preparation Solid Waste Effluents

TYPE OF OPERATION	TONS/DAY INPUT
Breaking and Sizing	
Controlled	0.87
UnControlled	0.87
Cleaning, Including Washing	
Controlled	39.96
Uncontrolled	1285-2767

7.4 DISRUPTION OF LAND AREAS

7.4.1 Mining (Surface) and Preparation

Land for surface mining is required for the active mining site, the spoil site, reclamation activities, the physical plant facility, access roads, and the water containment/treatment facility. The permanent land disruption is 2.56 acres/10^{12} Btu. Over a 30 year lifetime at 65% capacity a 1250 MWe plant will produce 729 x 10^{12} Btu resulting in permanent disruption of 905 acres. Temporary disruption, assuming a 5 year reclamation cycle, results in about 37 acres/10^{12} Btu or 437 acres of land each year.

7.4.2 Mining (Underground) and Preparation

Subsistence inevitably follows extensive underground extraction of coal. The elapsed time between the mining operations and the surface subsistence may be from several days to fifty or more years depending on: (1) the structural behavior of the overburden, (2) the depth of the excavation beneath the surface, (3) the percentage of coal mined, and (4) the method of mining used. The resulting damage to surface structures and land, and the destruction or contamination of water resources, constitutes a most pervasive kind of pollution.

The following indicates the difficulty of generalizing about the prediction of subsidence:

- Normally, where extraction has exceeded 70 percent, subsidence has occurred within a few years. However, there are instances on record (e.g., Macoupin County, Illinois), where only 50 percent extraction resulted in significant subsidence within 4 years.
- In the Macoupin County case cited above, the coal seams were about 7 feet in thickness under overburdens in excess of 200 feet. In Natroma Heights, Pennsylvania, with 60 percent extraction of a 42-inch seam under 150 feet of overburden, subsidence recently occurred some 65 years after the extraction was performed.

While it appears that the degree of subsidence will be less with increased depths of mining, there is no guarantee that the problem will be eliminated. In Great Britain, the mining of a seam 2100 feet below the surface has caused surface subsidence equal to 75% of the seam thickness. Lesser amounts of surface subsidence have been noted above seams in excess of 2400 feet.

For underground mining, the permanent land requirement is 1.83 acres/10^{12} Btu or about 760 acres over the plant lifetime. Incremental disruption is 17.11 acres/10^{12} Btu yielding approximately 23 acres/year. The actual disruption at any time will depend on the rate of subsidence and on the reclamation rate.

7.4.3 Transportation

The estimated land use requirements for coal transportation are: slurry pipeline, 19.9 acres/10^{12} Btu; rail, 33.9 acres/10^{12} Btu; and truck, 1.58 acres/10^{12} Btu.

7.5 MANPOWER REQUIREMENTS

Mining of coal, especially in underground mines, is labor intensive. The most recent data on mine productivity (for 1977) indicates production rates as follows:

Surface : 26 tons/man-day
Underground: 9 tons/man-day
Average : 14 tons/man-day

To supply the plant's average daily requirements would take a working force of 640 men for a 1250 MWe plant.

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SECTION 5. LIQUID METAL FAST BREEDER REACTOR

5. LIQUID METAL FAST BREEDER REACTOR (LMFBR)

1.0 INTRODUCTION

The LMFBR plant reference design is a 3400 MWt loop-type, sodium-cooled fast-breeder reactor plant with a nominal electrical rating of 1250 MWe. The physical LMFBR plant area will be about 70 acres, including the reactor building, switchyard, parking lot, access roads, and wet cooling towers. As a minimum, a buffering area of 400 acres is needed. This requires a total area of 500 acres. The plant design was developed by United Engineers for the Department of Energy (DOE) on the Energy Economic Data Base (EEDB) program as described in "Satellite Power System and Alternate Technology Characterization." Additional input was derived from the Proposed Final Environmental Statement "Liquid Metal Fast Breeder Reactor Program," WASH-1535.

The LMFBR is a nuclear fission reactor which, in addition to producing energy, converts U^{238} in its core to plutonium at a rate which produces more fissile material (Pu^{239} and Pu^{241}) than it consumes. Liquid sodium is used to remove heat from the reaction and to power the steam cycle to generate electrical power. Excess plutonium produced by the LMFBR will provide fuel for other breeders as well as conventional LWR's.

The description in this report is structured with the purpose of comparing one technology with another, both projected to the year 2000. First, it was necessary to make the technologies comparable in terms of electrical energy generation. 1250 MWe was chosen as being representative of large bulk power generation facilities in the year 2000.

The 1000 MWe LMFBR (About 2500 MWt) was scaled up to 1250 MWe because the cost estimate is also based on this plant and major equipment. Although scaling does provide a valid general representation of the 1250 MWe plant, a more representative or meaningful characterization would have been obtained if the LMFBR Program had proceeded further beyond the 1974 conceptual design phase.

During the past 10 years, the basic designs of the nuclear facilities have changed dramatically. Size of the units has increased to about 1250 MWe (3800 MWt) and extensive safety systems have been incorporated. Between now and the year 2000, size is assumed not to increase beyond present standards because of NRC safety concerns. However, safety will continue to be a major driving force in the design modifications of nuclear facilities. Investigations of the Three Mile Island accident will produce design changes for safety reasons in the near term. In the far term, through the year 2000, the continued striving for a "perfectly safe" form of nuclear energy will result in numerous design changes required by the regulatory agencies to enhance safety.

Although the LMFBR does not presently exist as a commercial bulk power generation source, it is assumed to be available in the year 2000. In the past few years, LMFBR technology has advanced beyond basic feasibility to the extent that prototype pumps, valves, heat exchangers, and other components have been built, tested, and placed in service in large demonstration plants throughout the world. Although a major engineering effort is necessary to demonstrate and deploy an energy concept, no technological breakthroughs are required for LMFBR. Remaining uncertainties mainly concern putting the existing technology into commercial practice by designing, constructing, operating, and maintaining commercial-scale units that can compete with other power plant concepts for the 21st century and beyond.

Pollution control equipment will continue to be required for power generation facilities. For a nuclear plant, better radiological control equipment will be developed and installed to minimize or eliminate entirely hazardous radionuclide emissions. In addition, pollutant abatement regulations are assumed to require no process stream discharges containing any pollutants. The only assumed exception to this basic assumption is the cooling tower blowdown. However, degradeable biocides and corrosion inhibitors are assumed to be used in the cooling towers. Ice prevention is accomplished through temperature control.

The reference liquid metal fast breeder reactor (LMFBR) described in this section is a single unit plant. It represents an envelope of the currently available design thinking for commercial plants of the five principle U.S. manufacturers of nuclear LWR plants, Atomics International (AI), Babcock & Wilcox (B&W), General Electric (GE), Westinghouse, and Combustion Engineering (CE). The basic nuclear plant is coupled to a balance-of-plant concept designed by United Engineers and Constructors (UEC) as described in their reports "Commercial Electric Power Cost Studies", and "Satellite Power System and Alternative Technology Characterization". The primary features of the UEC design are the Nuclear Stream Supply System (NSSS), four flow tandem compound turbine generator with supporting power conversion cycle equipment and systems, and the station cooling system using three mechanical draft wet cooling towers.

The overall design of the unit was based on the licensing, design, construction and operation criteria, standards, codes, and guidelines in effect circa January 1, 1978. The characterization represents the current state of technology in the late 1970's but projected to the year 2000. It must be realized that between the time the reference plant was designed and the year 2000, numerous changes will be made in the design requirements of the LMFBR levied by the various regulatory agencies. These design requirement changes will impact the basic design of the unit and its cost. Many of the changes will be derived from the lessons learned from LWR licensing experience. However, many more design changes will probably be required through the year 2000 as LMFBR operating experience, which cannot be quantified nor anticipated at this time, is gained. Caution must thus be exercised in the use of this design projected to the year 2000.

2.0 GENERAL PLANT CONFIGURATION

A plot plan for the LMFBR facility is shown in Figure 5-1. It consists of a 184-foot diameter cylindrical, domed, reinforced concrete containment, a reactor service building, two auxiliary buildings, two reactor decay cooling buildings, and the control building. These buildings are arranged in a cluster with the reactor containment building in the center. All are supported on a common base mat founded on rock. Two of the four steam generator buildings are located on either side and adjacent to the nuclear island buildings. The turbine building is located adjacent to the nuclear island buildings on the end opposite to the reactor service building.

Heat generated in the reactor is transferred by forced circulation of liquid sodium primary coolant to the intermediate heat exchangers. Then, the heat continues through a nonradioactive secondary sodium coolant system to steam generators in which superheated steam is produced. This steam drives a set of tandem-compound turbines. Waste heat released by condensation of exhaust steam from the turbine is rejected to the atmosphere through three mechanical draft, wet cooling towers.

The balance of the reactor plant systems includes reactivity control system, radwaste system, service waste systems, combustible gas controls, fuel handling, fuel storage, reactor makeup water system, the primary component cooling water system, and the air cleanup system. The balance of the conventional portion of the plant includes the usual transformer, switchgear and switchyard components, and the connection to the distribution lines. The main condenser heat rejection system includes makeup water intake and discharge structures, a circulating water pumphouse, makeup water pretreatment facilities, and three mechanical draft, wet cooling towers.

PLANT NOMENCLATURE

1. Reactor Containment
2. Reactor Service Building
3. Turbine Building
4. Heater Bay
5. Control Building
6. Diesel Building
7. Administration Building
8. Auxiliary Building No. 1
9. Auxiliary Building No. 2
10. Auxiliary Heat Transfer System Bay No. 1
11. Auxiliary Heat Transfer System Bay No. 2
12. Steam Generator Building No. 1
13. Steam Generator Building No. 2
14. Steam Generator Building No. 3
15. Steam Generator Building No. 4
16. Plant Maintenance
17. Auxiliary Boiler
18. Water Treatment
19. Loading and Unloading Facility
20. Non Essential Switchgear Building
21. Transformer Area
22. Security Building
23. Make-Up Water Intake Structure
24. Make-Up Water Pretreatment Building
25. Holding Pond Plant Effluent
26. Fire Water Pump House
27. Fire Water Storage Tasks
28. Ultimate Heat Sink
29. Cooling Towers
30. Cooling Towers Switchgear Building
31. Switchyard
32. Fuel Oil Storage Tank
33. Parking Area
34. Guardhouse
35. Railroad
36. Security Fence

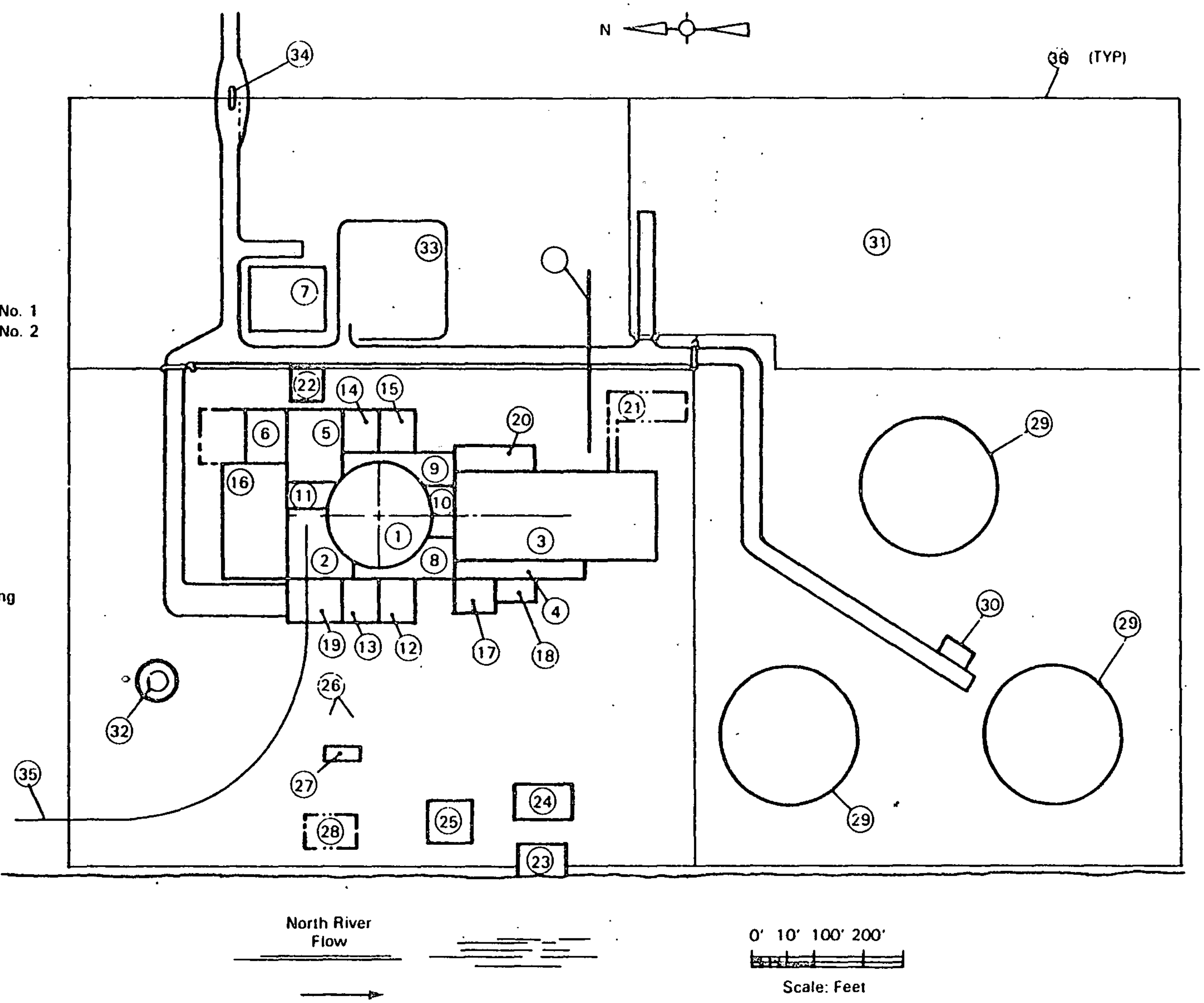

Figure 5-1. The Plot Plan for the LMFBR Facility

3.0 THERMODYNAMIC CYCLE CHARACTERISTICS

The LMFBR primary system consists of a liquid, sodium-filled nuclear reactor having a reactor core containing low enriched uranium and plutonium oxides in approximately 670 fuel and 1,100 blanket assemblies. The core is refueled by replacing approximately one-third of the assemblies after achieving a 67,000 MWD/T average burnup. Both the new and spent reactor fuels are radiologically hot and must be stored in heavily shielded areas.

The reactor produces approximately 3417 MWt at nominal full power. The LMFBR Heat Transport System removes the heat generated by the reactor core and converts it to the rotational mechanical energy required by the generator to produce electric power. The overall system consists of a radioactive primary coolant system, a nonradioactive secondary coolant system, a steam generation system, and a steam plant system, the latter including the turbine that delivers the required mechanical energy to the electrical generator. A simplified systems diagram is given in Figure 5-2.

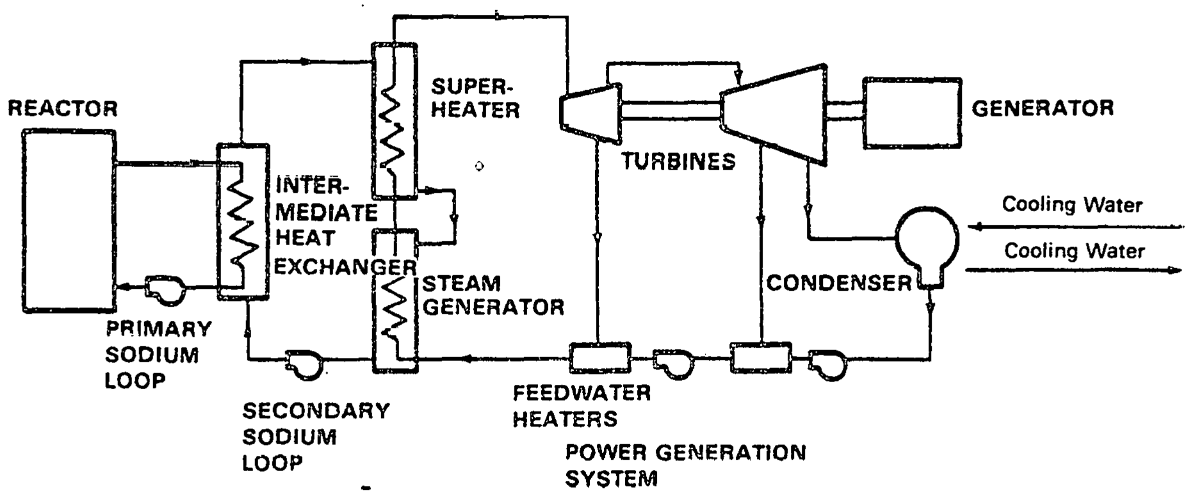

Figure 5-2. Simplified Diagram of Heat Transfer System

The primary coolant system consists of several redundant circulating loops that conduct sodium from the core exit plenum of the reactor vessel and circulate it through internediate heat exchangers. Here, the heat is transferred to the sodium of the secondary coolant system. The primary sodium then returns to the reactor vessel. In the secondary system, secondary sodium is heated in the intermediate heat exchangers and is circulated to the steam generation system. There are four parallel primary loops and four secondary loops, one serving each primary loop.

Two basic arrangements, the pool- and loop-type configurations, for the primary coolant system have been proposed. These are depicted schematically in Figure 5-3. In the pool-type configuration, the reactor, intermediate heat exchangers, primary pumps, and interconnecting piping are all immersed in a large primary tank filled with sodium. In operation, sodium is drawn from the bulk content of the tank by the primary pumps and is forced through the reactor. Then, the sodium flows by gravity through the intermediate heat exchangers and discharges back to the bulk sodium in the primary tank. The driving force for intermediate heat exchanger flow is the difference between the levels of sodium over the reactor and in the remainder of the primary tanks. With this configuration, the primary tank with its cover and the tubes and tube sheets of the intermediate heat exchangers constitute the primary coolant system boundary.

The primary coolant arrangement is the loop-type configuration where the primary pumps and the intermediate heat exchangers are located external to the reactor vessel. Either hot or cold leg pumps could be used in the primary system. The primary loop piping is elevated and guard vessels are provided around the pump, intermediate heat exchanger, and reactor vessel so that leaks in the primary piping or these components cannot cause the sodium level in the reactor to drop below the minimum safe level. Thus, the loop nozzles would be covered, and continuous heat removal by sodium circulation through the loops could be permitted. The LMFBR characterized in this section is a loop-type plant.

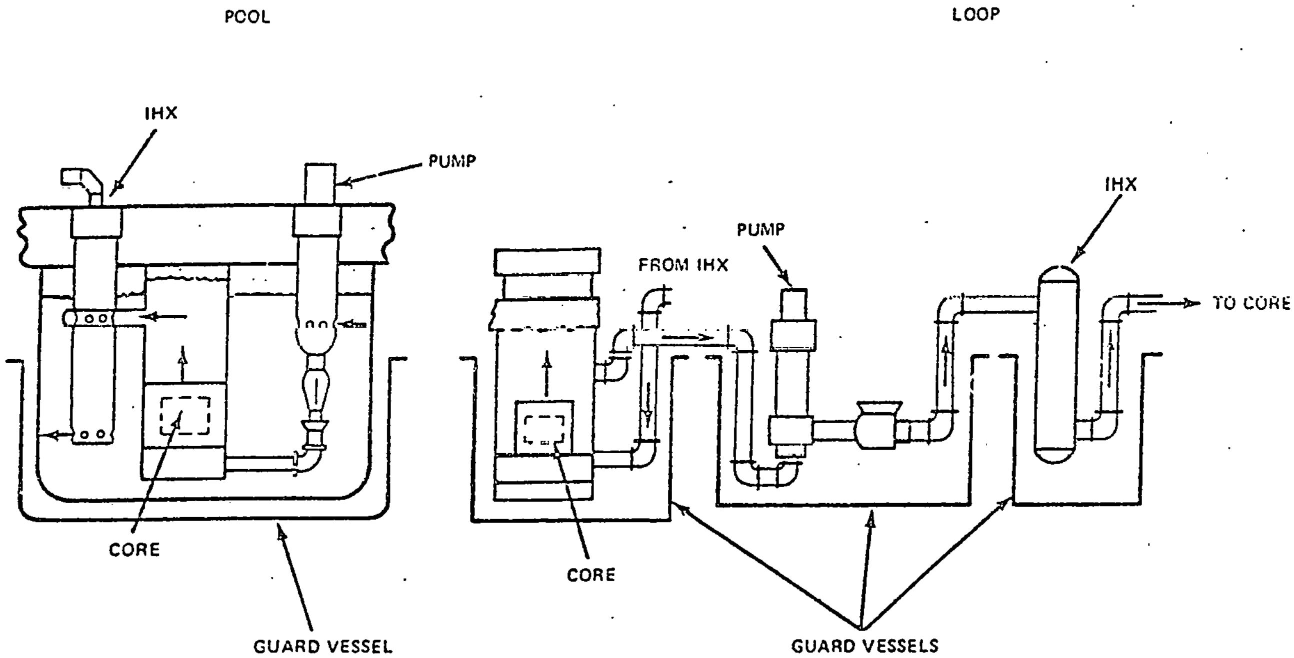

Figure 5-3. Pool and Loop-type Primary Coolant System Configurations

The primary sodium system is designed to operate at a lower pressure than the secondary system. Thus, should a leak develop in an intermediate heat exchanger between these two systems, any leakage should progress from the nonradioactive secondary system into the radioactive primary system. Finally, even though such leakage would not result in a radiological problem in the secondary system, the intermediate heat exchangers are designed to facilitate removal or replacement of faulty tubes.

The overall steam cycle is expected to be similar to that of modern fossil-fired steam-electric power plants. The turbine designed assumed in this study is a set of tandem compound fossil turbines.

3.1 REACTOR HEAT-GENERATION SYSTEM

The reactor heat-generation system consists of the reactor core, control rod drives, and reactor vessel. The core is an array of fuel assemblies, which are vertically disposed and surrounded by one or two rows of radial blanket assemblies and one row of reflector assemblies. Control assemblies are interspersed with the fuel assemblies in a regular pattern.

The fuel material is mixed plutonium-uranium oxide. Fuel elements are helium filled to enhance heat transfer across the gap between fuel and cladding. Blanket material, both axial and radial, is depleted uranium oxide. The control absorber material is assumed to be boron carbide (B_4C), although other materials are also under consideration.

The core component handling system has the function of handling fuel and other core assemblies from their receipt at the reactor plant through acceptance testing, storage, conditioning, and insertion into the reactor core; and during removal of the core assemblies from the reactor, the handling system provides for the storage for decay of post-irradiation heat generation (commonly called "decay heat storage"), and the inspection, cleaning, and packaging of this material for shipment to reprocessing facilities.

A number of different basic design approaches have been proposed for commercial-size LMFBR power plants for the removal of spent core assemblies from the reactor and for their decay heat storage prior to shipment from the plant site. The principal differences between the approaches are in the location of the decay storage facilities and in the method of transferring assemblies between the core and storage positions. Reduction of the reactor down-time necessary for refueling operations to the minimum length of time consistent with plant safety is aimed at improving plant availability and consequently plant economics, the prime goal of all approaches.

3.2 AUXILIARY SYSTEMS

The plant contains a number of auxiliary systems to perform specific support functions:

- Liquid metal receiving and processing
- Inert gas receiving and processing
- Auxiliary heating and cooling
- Radioactive waste processing
- Servicing and utility functions

Of these systems, radioactive waste processing systems are perhaps the most important in terms of environmental considerations and are described briefly in Section 4.2.

The LMFBR primary system is a completely closed system in which the sodium and cover gas* are continually pruified to maintain radioactivity at low levels. Four radioactive waste processing systems are provided:

(1) Gaseous waste system, subdivided into reactor cover gas and cell atmosphere purification systems

(2) liquid waste system

(3) solid waste system

(4) sodium waste system

Table 5-1 presents key plant parameters.

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* Argon gas is used to keep the sodium atmosphere inert.

Table 5-1. Key Plant Parameters for LMFBR Primary System

Parameter	Operating Description
Thermal Power, MWt	3417
Electric Power, MWe (gross)	1313
Electric Power, MWe (net)	1250
Plant Efficiency, Percent	36.6
Steam Conditions, Turbine Inlet, Full Power	
Pressure, psig	2200
Temperature, ^{o}F	850
Feedwater Temperature, ^{o}F	470
Feedwater Flow, 10^6 lb/hr	12.81
Turbine Steam Flow, 10^6 lb/hr	12.81
<u>Heat Transport System</u>	
Number of Coolant Loops	
Primary	4
Intermediate	4
Sodium Flow Rate, 10^6 lb/hr	
Primary (total/loop)	128.8/32.2
Intermediate (total/loop)	120.1/30.0
Pumps	
Primary Pump	Single-State Centrifugal, 77,520 gpm at 375 ft
Intermediate	Single-State Centrifugal 68,980 gpm at 300 ft
Intermediate Heat Exchangers	Straight tube counter-flow, one/loop
Steam Generators	One-through, straight tube, two/loop, 427 MWt each

3.3 INSTRUMENTATION AND CONTROL

The plant instrumentation and control system consists of three basic parts: the protection system, data system, and control system. The protection system provides for the measurement of neutron flux density from startup to full power, coolant and component temperatures, system pressures, sodium flows and levels, gamma radiation, radioactive gases and particulates, and other parameters of interest or necessity.

3.4 REACTOR CONTAINMENT

An important safety feature of the LMFBR commercial plant concept is the multiple containment of fission products generated in the fuel elements during reactor operation. The barriers to fission produce release are the fuel element cladding, the boundary of the primary coolant system, and the outer reactor containment.

The outer containment consists of a leak-tight cylindrical steel or steel-lined concrete building having a flat bottom and hemispherical or ellipsoidal dome. The containment building houses the reactor and entire primary coolant system, spent fuel handling and storage facilities, and sodium service systems related to the primary system.

3.5 TURBINE GENERATOR CONFIGURATION

The turbine configuration consists of two one-half capacity tandem compound, four flow machines with 33 1/2-inch last stage plants designed and operated at 3600 rpm. Inlet steam conditions at the HP throttle valves are 2200 psia and 850 ^{o}F. This reactor plant designed provides the superheat so the inlet steam is not at saturation and resembles steam conditions in a fossil-fired power plant.

Turbine shaft power and generator output is about equally distributed to the two shafts. Each of the two generators is rated at 722 MVA with 0.90 PF, 26,000 V, 3 phase and 60 Hz output. Fixed and generation losses respectively account for 1,509 kW and 9,934 kW per generator, thus resulting in a gross generator output capacity of 1,313,000 kW, before accounting for auxiliary electrical loads.

3.6 CONDENSER-HEAT REJECTION SYSTEM

Two multi-pressure, single-pass surface condensers with divided fabricated steel water boxes and shell are provided. The condensers are designed to condense the low-pressure turbine outlet steam and feedwater pump auxiliary turbine drive exhaust steam by dissipating the heat to three mechanical draft, wet cooling towers. Each condenser contains about 325,000 ft^2 of condensing surface made up of 1-1/8 inch diameter, 20 BWG 90-10 CuNi tubes.

The three main mechanical draft water cooling towers are each sized for one-third of the requirements. Each tower is designed to cool 195,000 gpm of water from 118° to 92°F when operating at a wet bulb temperature of 74°F. Each tower employs a reinforced concrete-filled structure combined with components for water distribution, fill spash service, support system, drift eliminators, louvers, and fan deck. The fan deck provides a stable base for the 12 fan cylinders and mechanical equipment. Each fan is 33 ft in diameter and operates in an 18 ft high glass reinforced-polyester velocity recovery fan stack. The hot water distribution system includes a circular flume distribution basin and metering orifice which uniformly distributes the hot water over the fill.

3.7 FEEDWATER HEATERS

Feedwater flow from the condenser enters a six-series reverse-cascade feedwater heaters designed to achieve a final feedwater temperature of 440°F at 12.81×10^6 lb/hr. The first five stage heaters are low pressure and the final stage only designed for full steam generator pressure. Steam for the feedwater heaters is provided from the moisture separator, various extraction points throughout the steam cycle, and other residual stream flows. A total of 5901.4×10^6 Btu/hr is added to the feedwater before entering the boiler as shown in Figure 5-4. The condensate and feed pumps contribute small amounts of energy.

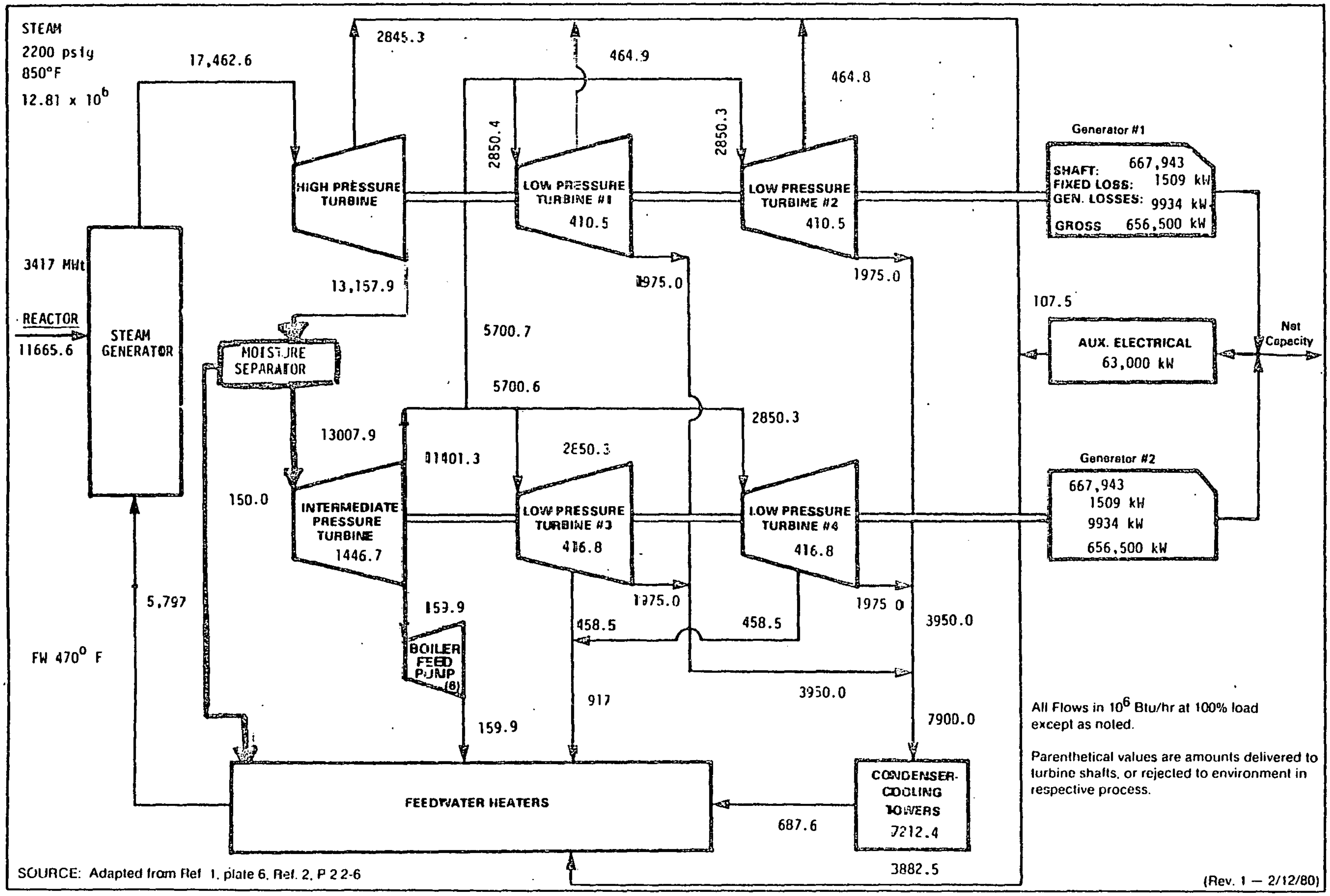

Figure 5-4. Simplified Cycle Schematic - 1250 MWe - Reference LMFBR Facility

3.8 GENERATOR LOSSES AND ANXILIARY ELECTRIC ENERGY USE

The total power delivered to the turbine shaft is about 1,334,214 kWh. Various generator inefficiencies result in the loss of 21,214 kW or 1.59 percent of the shaft power as fixed and generation losses. Approximately 63,000 kWh is required to support the plant operation, resulting in a net output of 1,250,000 kWh.

3.9 FUEL USE AND LOGISTICS

A summary of typical annual fuel requirements for a 1250 MWe LMFBR plant is presented in Table 5-2. The nuclear fuel is uranium--plutonium oxide; quantities stated are for the heavy metal (uranium or plutonium) content only. The axial and radial blankets are listed separately. The following estimates are the <u>nominal</u> plant operations.

The refueling of the 1250 MWe LMFBR power plant operating at nominal capacity requires about 23 Metric Tonnes Heavy Metal (MTHM) as the nuclear fuel. The blanket material contains about 64 MTHM which breeds fissile Pu. The Pu is recovered via reprocessing, which results in the generation of high-level wastes. These waste products are made up of fission products and fuel element hull material, stainless steel. Austenitic stainless steel is used as part of the replaceable fuel elements; the steel is not chemically consumed but is rendered radioactive in the reactors. The steel cannot be decontaminated and thus is considered consumed, rather than recoverable, and disposed of as waste.

Table 5-2. LMFBR Fuel Design Parameters

Parameters	LMFBR-Pu/U/Th/Th
Reactor Thermal Output	3,417 MWt
Number of Elements	
Core Fuel	678
Axial Blanket	678
Radial Blanket	420
Fuel Type	Oxide Fuel
Breeding Ratio	1.1417
Initial Core (Average)	
Discharge Burnup	45,983 MWD/MTHM
Core Loading	22.668 MTHM
Fissile Plutonium Loaded	154.314 kg/MTH_i
Fissile Plutonium Discharged	136.713 kg/MTH_i
Initial Uranium Enrichment	0.20 w/o U-235
Final Uranium Enrichment	0.13 w/o U-235
Replacement Core Loadings	
Discharge Burnup	67,590 MWD/MTHM
Core Loading	23.316 MTHM
Fissile Plutonium Charged	154.315 kg/MTH_i
Fissile Plutonium Discharged	134.243 kg/MTH_i
Initial Uranium Enrichment	0.20 w/o U-235
Final Uranium Enrichment	0.13 w/o U-235
Axial Blanket	
Loading	19.038 MTHM
Fissile Plutonium Discharges	22.691 kg/MTH_i
Initial Uranium Enrichment	0.2 w/o U-235
Final Uranium Enrichment	0.18 w/o U-235
Radial Blanket	
Loading	44.796 MTHM
Fissile Plutonium Discharged	20.895 kg/MTH_i
Initial Uranium Enrichment	0.2 w/o U-235
Final Uranium Enrichment	0.18 w/o U-235

The LMFBR power plants and fuel cycle facilities consume chemicals and certain replaceable components in addition to water, fuels, and the materials of construction. These additional requirements are:

(1) Chemicals for treating natural water for cooling water systems. The use depends on the water quality; the chemicals most commonly used are chlorine and sulfuric acid.

(2) Ion-exchange resins for removal of radioactivity from aqueous waste streams. The quantity depends on source terms and methods for treatment.

(3) Ion-exchange resins for purification of water for internal plant uses. The quantity used depends on the water quality and the type of resin.

(4) Chemicals for regeneration of ion-exchange resins. These chemicals are usually sulfuric acid and sodium hydroxide; the quantity used depends on water quality.

(5) Containers for packaging radioactive effluent from the radioactive waste systems. The number of containers depends on the amount of radioactive materials to be disposed of and the particular process used in the various systems. These containers are steel, concrete, or other common structural materials.

(6) Sodium coolant for the primary and secondary coolant loops of the power plant.

(7) Miscellaneous chemicals, principally nitric acid and solvents for the reprocessing plant. These are not critical materials from a resource standpoint, and amounts not recycled are handled as wastes.

All of the above chemicals are of common types and are used in moderate amounts relative to U. S. industrial practice. Sodium is a low-cost industrial material obtained from virtually inexhaustible salt resources. Sodium is not chemically transformed in its use as a coolant and is retained except for small removals during the plant lifetime. The sodium in the primary loop is rendered radioactive, which may make it unacceptable for uses other than as primary coolant in LMFBR power plants.

4.0 ENVIRONMENTAL CHARACTERISTICS

Numerous reactor plant systems, even under normal conditions, become contaminated with radioactive elements. These elements can come from the fuel itself, impurities in the fuel cladding, activated wear products, or other sources. Because several systems are contaminated, normal maintenance, operations, and leaks will lead to release of some of these elements.

The building ventilation systems and processed liquid effluents are the transport mechanisms for release of these radioactive elements. Areas which have the potential for contamination are ventilated through high-efficiency particulate filters which remove > 99.9 percent of the particles in the air greater than 0.3 microns. Potentially contaminated liquid effluents are monitored or processed to remove radioactive elements primarily by filtration and ion exchange. In each case, not all of the radioactive elements can be prevented from entering the biosphere. Consequently, radioactive elements are emitted to the biosphere by the LWR.

4.1 AIR EMISSIONS

Radioactive noble gas emissions are the important gaseous emissions from an LMFBR plant. Table 5-3 shows the estimated airborne radionuclide releases from the reference 1250 MWe LMFBR facility.

Table 5-3. Postulated Radionuclide Releases--1250 MWe LMFBR Power Plant at 70% Capacity Factor

Nuclide	Atmospheric Release Ci/year
H-3	65.63
Ar-39	87.50
Kr-85m	.33
Kr-85	.44
Kr-87	.44
Kr-88	.54
Xe-133	.03

Both the dose from airborne releases and radiation from the LMFBR power plant are well within the guidelines proposed in Appendix I of 10 CFR 50, currently a guide for LWR's.

LMFBR facility chemical discharges are assumed to be the same as the LWR. These discharges are from the cooling towers and are comprised of chlorine, chromates, and zinc. As with the LWR facility, chemical discharges present no hazard to the environment.

4.2 LIQUID EFFLUENTS

The aqueous chemical wastes from a nuclear power plant generally enter the environment via the blowdown stream from a closed-cycle cooling system or the circulating cooling water stream from an open-cycle system. In actual practice, the chemical composition of these waste streams is as varied as the number of existing discharges. Nevertheless, the nature of some of these wastes can be categorized according to their origin and somewhat by their chemical makeup. The major sources of the waste streams from a nuclear power plant are those originating from the condenser cooling system and the process water system. All other waste streams are minor compared to them. Negligible radioactive effluents will be emitted from an LMFBR plant. A summary of effluents is provided in Table 5-4.

Table 5-4. LMFBR Wastewater Effluents at Nominal (1250 MWe) Operation

Chemical	Amount (Tons/hr)
BOD	0.000
Chromates	0.000
Phosphates	0.008
Boron	0.056
Acids	0.014
Organics	0.012
Chlorine	0.005

Radiological	Amount (Curies/yr)
Uranium	neg
Ra-226	0.000
Th-230	0.000
Th-234	0.000
Co-60	0.774
Sr-90	0.257
I-131	15.24
Cs-134	9.38
Cs-137	7.97
Ce-144	0.030
Pu	0.000
Tritium	586
Ru-106	0.014
Other activation and fission products	70.32

4.3 SOLID WASTES

Solid wastes generated at the reactor will consist typically of filters from the heating and ventilation system, deactivated primary coolant sodium cold traps, analytical laboratory and liquid waste treatment residues, contaminated tools and parts, and waste such as plastic bags, footcovers, paper towels, and protective clothing. These wastes will be compacted and packaged in 55-gallon sealed drums. Then, the wastes are shipped to a low-level waste burial ground. About 9.4 ft^3 of tritium waste per year in the form of $Ca(O^3H)_2$, will be included in these solid wastes.

About 3,117 curies of beta-gamma waste and about 30,000 curies of tritium waste will be generated each year.

4.4 REJECT WASTE HEAT

The 1250 MWe LMFBR would reject about 7.1×10^9 Btu/hr through the cooling towers. In addition, there will be miscellaneous thermal losses to air (called general plant losses) amounting to less than 1%, a value typical of present-day nuclear facilities.

The primary environmental controls for radioactivity are:

- Control of radioactive noble gases
  - Reactor cover gas purification
  - Cell atmosphere purification system
- Liquid waste system
- Solid waste system
- Sodium waste system
- Gaseous waste system

  The gaseous waste system processes all gases that can become contaminated with gaseous or volatile radioactive species. These species include:

  (1) Fission products escaping from failed fuel, notably the noble gases, halides, and alkali metals

  (2) Ar-39 generated from potassium impurities in the coolant

  (3) Activated sodium aerosol and vapor

Two separate systems will be utilized to control radioactive noble gases. These two systems are: (1) the reactor cover gas purification system, and (2) the cell atmosphere purification system.

- Liquid Waste System

  The liquid waste system processes all potentially contaminated liquids before the liquids leave the plant. The sources of the liquid waste streams are the fuel handling area, the sodium waste system, laboratory areas, laundry, maintenance, and other support systems. The quantity of liquid waste entering the system is expected to be between 20,000 and 40,000 gal/year, which is primarily low-level radiation or contamination. (The liquid waste system will not handle tritium-containing effluents from the steam system; this waste stream has been discussed previously.)

- Solid Waste System

  Solid waste will be generated by waste systems, fuel handling operations, and laboratory and maintenance operations. The waste will be in such forms as spent resins, sludges, filters, clothing, and tools.

- Sodium Waste System

  The purpose of the sodium waste system is to convert small amounts of metallic sodium waste, both radioactive and nonradioactive, into a less reactive form.* The principal sources of sodium waste at the reactor are spent cold traps. Other possible sources are sodium-contaminated hardware (equipment and spent fuel assemblies).

4.5 LAND AND WATER USE

Approximately 70 acres of land will be required for facilities associated with the LMFBR power plant; namely, the reactor buildings, turbine building, switchyard, parking lot, access roads, and cooling towers. As a minimum, an exclusion area of at least 400 acres is needed, and presently most LWR stations are on even larger sites.

Decisions relating to the siting of LMFBR power plants are expected to be guided by practices, guidelines, and criteria. These will have been developed and established through experience gained in the construction and operation of nearly one full generation of large, LWR nuclear power plants and siting of LMFBR demonstration power plants. Major changes are not anticipated in the guidelines currently in use.

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* Sodium waste may not be processed onsite for LMFBR power plants.

A number of economic, safety, and engineering factors will determine the choice of a site for a specific LMFBR power plant. The acceptability of environmental impacts caused by the construction and operation of the plant is also under consideration. LMFBR siting must be responsive to public concern for the quality of the environment.

Consumptive water use results primarily from cooling tower evaporative losses, cooling tower blowdown, and general plant use. By far, the largest consumers of water are the mechanical draft, cooling towers which use approximately 844,000 gal/hr. Table 5-5 identifies this and other plant water uses.

Table 5-5. Water Use - 1250 MWe LMFBR

USE	Million Gallons/Day	
	100% Power	70% Power
Cooling Tower Evaporation	21.9	15.33
Cooling Tower Blowdown	6.35	4.45
General Plant Use	< 1	< 1
TOTAL	29.25	20.78

5.0 CONSTRUCTION AND OPERATION CHARACTERISTICS

Studies undertaken by United Engineers and Constructors for the AEC indicate that construction labor requirements for LWR power stations range from about 6 man-hours/kW for a multiple-unit station with 2,000,000 kW units to 8 man-hours/kW for a single 1,300,000 kW unit station. It is assumed that the construction labor requirements for LMFBR Power Stations will be approximately the same as those for LWR's.

The construction of an LMFBR facility is subject to delays similar to an LWR which include:

- Litigation
- Financial problems
- Large changes in the need for power
- Licensing requirements for facility changes and back fits
- Licensing holds

There are other reasons for extended construction periods that may be experienced. Without any of these delays, a 1250 MWe LMFBR facility could be constructed in 72 months. If the delays expected to occur are included in this estimate and licensing is also included (two step process with a construction permit and operating license included) the LMFBR facility could be completed in 12 years. (Recent experience with LWR construction and the novel design of the LMFBR indicates that a 12 year completion is almost a certainty.) During the onsite construction period, an estimated 11.5 million man-hours of direct craft labor would be required primarily from 16 different labor types as described in Table 5-6. Indirect labor hours are also included.

Normal operation of the facility would require a plant staff averaging 225 persons and over 450,000 man-hours per year as shown in Table 5-7. The number of personnel on site would vary considerably from to time depending on the operation of the unit. When the unit is down for refueling/repair, the total number of personnel on site would peak at a number considerably higher than 225.

Table 5-6. Direct Craft Labor Summary--1250 LMFBR Plant
Cost Basis - January 1978

Craft Description	Site Labor Hours	% Hours
Asbestos Worker	133,850	1.1
Boiler Maker	745,282	5.9
Bricklayer	142,362	1.1
Carpenter	1,516,060	12.0
Dock Builder	3,578	0.0
Electrician	2,042,690	16.1
Iron Worker	1,447,257	11.4
Laborers	1,428,556	11.3
Millwrights	189,303	1.5
Operating Engineers	950,505	7.5
Painters	223,764	1.8
Pipefitters	3,510,508	27.6
Plumbers	750	0.0
Roofers	14,042	0.1
Sheet Metal Workers	138,163	1.1
Teamsters	193,330	1.5
TOTAL FOR PLANT	12,680,000	100.0

Table 5-7. Staff Requirements for LWR Plant*

AREA	STAFF
Plant Manager's Office	
Manager	1
Assistant	1
Quality Assurance	3
Environmental Control	3
Public Relations	1
Training	2
Safety	3
Administrative Services	16
Health Services	3
Security	56
SUBTOTAL	89
Operations	
Supervision (excluding shift)	2
Shifts	33
SUBTOTAL	35
Maintenance	
Supervision	8
Crafts	16
Peak Maintenance Annualized	55
SUBTOTAL	79
Technical and Engineering	
Reactor	1
Radiochemical	2
Instrumentation and Controls	2
Performance, Reports and Technicians	17
SUBTOTAL	22
TOTAL STAFF	225

* Single unit 701-1300 MWe

5.1 OPERATING STATISTICS AND ANNUAL GENERATION

Past experience indicates that a 70% availability is reasonable for large nuclear and fossil-fueled power plants. The actual data studies were from nuclear and coal-fired baseload units 400 MW and larger in nameplate capacity. For analytic purposes, the individual units were categorized by their size, vintage, and primary fuel burning capabilities.

The four primary utility industry measures of powerplant performance are capacity factor, availability factor, equivalent availability, and forced outage rate. The capacity factor measures the power generated by the unit versus its maximum dependable capability to produce power. The availability factor establishes only the percentage of time the unit was capable of producing power. The equivalent availability adjusts the availability factor for partial outages or deratings of the unit. The forced outage rate defines that percentage of time the unit was forced out of service due to equipment or operational malfunction. Collective review of these four indices is often taken as the measure of a unit's performance.

No single index tells the overall performance story for a unit. The annual Availability Factor establishes only the percentage of time during the year the unit was capable of producing power. This includes time when the unit was capable of producing power but was not in service because more economical units were being utilized. Thus, the Availability Factor does not measure the ability of a unit to operate at a specific power level when called upon by the utility. Rather, it measures only the unit's capability to produce at a power level ranging from 0 to 100%. The Equivalent Availability provides an adjustment to the Availability Factor by factoring in the effect of partial deratings (losses in MW output capability) due to partial forced and scheduled outages. The Equivalent Availability is essentially "equivalent to" the percentage of the year during which the unit was available for operation at full capacity. The Equivalent Availability, however, provides no measure of the effect of full forced outages or actual megawatts generated by a unit. These unit performance parameters are measured by the Forced Outage Rate and Capacity Factor.

Typically, a large nuclear station, such as the type characterized here, would be placed first or at least close to first in the utility's loading order. Thus, it would be little affected by the customer's demand, since it would serve to satisfy part of the minimum customer load. However, a factor of .97 has been applied to the calculated plant availability to simulate a small reduction in plant operation due to inadequate customer demand.

Scheduled maintenance and affecting outages for large nuclear facilities vary from 4 to 8 weeks per year, and recent forced outage rates range from 5 to 20 percent. Here, 8 weeks of maintenance and refueling and a 15 percent forced outage rate is used for conservation to determine unit availability. Thus, plant availability is determined:

$$\text{Plant Availability} = \frac{52-8}{52} \times (1-.15) \times 100\% = 72\%$$

Adjusting for customer demand reduction results in:

$$\text{Capacity Factor} = (72\%)\ (.97) = 70\%$$

At this capacity factor, the reference 1250 MWe LMFBR facility would generate 7.665×10^9 kWh/yr.

6.0 COST CHARACTERIZATION (LMFBR)

The Energy Economic Data Base (EEDB) report prepared for DOE by United Engineers and Constructors details the base capital costs estimated for the 1250 MWe reference liquid metal fast breeder reactor power plant. Direct and indirect capital costs presented in the EEDB are on a consistent January 1, 1978 dollar basis. They are for the 1390 MWe (3800 MWt) plant which provided much of the basis for the physical system characterization presented in the previous section.

6.1 DIRECT CAPITAL COSTS

The EEDB costs have been appropriately adjusted to reflect reduced power levels and flow rates incorporated into the 1250 MWe reference liquic metal fast breeder reactor system. Specifically, the major modifications that affect the reference system's capital costs (as compared to the 1390 MWe EEDB design) include a 10.1% reduction in the following system component capacities and design characteristics:

1. Sodium coolant flow through reactor vessel
2. Steam flow through steam generators and turbines
3. Turbine shaft power, generator output, net plant capacity, and heat rejection system

Base direct capital cost includes the costs of all materials, components, structures and associated direct craft labor necessary to construct the reference facility at the plant site. Delivered costs for components, structures and materials are used. Base indirect costs include site temporary construction facilities, payroll, insurance, and taxes, and other construction services, such as home and field office expenses, field job supervision, and engineering services. Specifically excluded from the base construction cost estimate are several items that are sensitive to the particular policies and preferences of the individual utility, and the specific plant site and prevailing economic factors being considered. These exclusions include the following list of items.

1. Owner's Costs - Consultants, Site Selection, etc.

2. Federal, State and Local Fees, Permits and Taxes

3. Interest on Capital Construction Funds

4. Price Escalation during Construction

5. Contingency Funds

6. Owner's Discretionary Items - Switchyard and Transmission Costs, Waste Disposal Costs, Spare Parts, and Initial Fuel Supplies

We reviewed the cost estimates made in the EEDB for the 1139 MWe reactor design and where appropriate adjusted the costs using the capacity ratio/exponent estimating technique. This technique, which is generally accepted by the electric power generation industry for making cost estimate modifications, uses the following equation to adjust component costs for small to moderate change component capacity:

$$\text{Cost of Component B} = \text{Cost of Component A} \times \left(\frac{\text{Capacity of B}}{\text{Capacity of A}}\right)^{\alpha}$$

where component A and Component B are of similar design and performance, differing only in the size or capacity, and where α is given by the following:

Account	Description	Cost Estimating Exponent (α)*
20	Land and Land Rights	Not Applicable
21	Structures and Improvements	.20
22	Reactor Plant Equipment	.40
23	Turbine Plant Equipment	.85
24	Electric Plant Equipment	.37
25	Miscellaneous Plant Equipment	.20
26	Condenser Heat Rejection System	.50

Table 5-8 shows the original EEDB cost estimate by "2-digit" accounts. The applicable cost estimating factors and the resulting 1250 MWe reference

* Argonne National Laboratory estimate based on light water reactor cost estimating exponents.

system cost estimates are also shown. Costs for land would not vary measurably for the small incremental plant capacity considered here. Thus, this account has been assigned a cost estimating factor of unity; the land costs shown assume the use of a 500-acre site valued at $4,480 per acre.

Table 5-8. Estimated Direct Capital Costs for 1250 MWe Liquid Metal Fast Breeder Reactor Reference System (January 1, 1978 Dollars)

Account	Description	1139 MWe EEDB[a] Cost ($1000)	CEM[b]	1250 MWe Reference System Cost ($1000)
20	Land and Land Rights	2,240[c]	1.00	2,240
21	Structures and Improvements	64,890	$0.899^{0.20}$	63,523
22	Reactor Plant Equip.	338,376	$0.899^{0.40}$	324,268
23	Turbine Plant Equip.	98,239	$0.899^{0.85}$	89,739
24	Electric Plant Equip.	32,009	$0.899^{0.37}$	30,773
25	Misc. Plant Equip	11,564	$0.899^{0.20}$	11,320
26	Condensate Heat Rejection System	16,480	$0.899^{0.50}$	15,626
	TOTAL DIRECT EQUIPMENT AND MATERIALS	561,558		537,489
	Site Labor Costs	172,782		165,376
	TOTAL DIRECT BASE CONSTRUCTION COSTS	734,340		702,865

(a) EEDB, Energy Economic Data Base.

(b) CEM, Cost Estimating Multiplier, see text for discussion.

(c) Assumes 500 acres at $4,480/acre.

Average site labor costs for the 1390 MWe EEDB facility are estimated from approximately 13.25 million man-hours at a craft averaged cost of $13.04 per man-hour. Direct field labor requirements and costs have been assumed to be directly proportional to the equipment and materials costs. Resultant direct craft man-hours for the reference facility are thus estimated to total 12.68 million man-hours, or over $165 million.

6.2 INDIRECT CAPITAL COSTS

Indirect capital costs which are associated with the construction of large liquid metal fast breeder reactor power plant, would be relatively insensitive to the plant capacities used in the EEDB and as the reference system described here. Thus, except for payroll related expenses, indirect capital costs for the 1250 MWe reference liquid metal fast breeder reactor plant have been taken to be the same as those for the EEDB 1390 MWe plant. Construction payroll, insurance, and taxes (as well as field job supervision costs) were assumed to be proportional to the reference system direct field labor costs. This assumption reduced the Construction Services Account (#91) by $1310 thousand and reduces the Field Office Engineering and Services Account (#94) by $1055 thousand over those costs estimated in the EEDB.

Indirect capital costs summarized in Table 5-9 at the "2-digit" account level, total $262,590,000. These costs are about 37% of the direct capital cost estimated for the reference liquid metal fast breeder reactor system. These costs are more than twice the indirect costs associated with coal burning facilities for similar capacities. Safety and inspection requirements are a major contributor to this factor.

Table 5-9. Estimated Indirect Capital Costs for 1250 MWe Liquid Metal Fast Breeder Reactor Reference System (Jan. 1, 1978 Dollars)

Account	Description	1250 MWe Reference System Cost ($1000)
91	Construction Services	89,690
92	Home Office Engineering and Services	136,300
93	Field Office Engineering and Services	36,600
	TOTAL INDIRECT CAPITAL COSTS	262,590

6.3 OPERATION AND MAINTENANCE COSTS

Annual operation and maintenance (O&M) costs for the 1250 MWe reference liquid metal fast breeder reactor facility have been estimated. This data is based on cost estimating relationships in a recent Oak Ridge National Laboratory (ORNL) document entitled, "A Procedure for Estimating Nonfuel Operation and Maintenance Costs for Large Steam Electric Power Plants." Data is available in the EEDB.

Generally, O&M costs for a nuclear power plant may be considered to be composed of six cost categories. O&M costs may be either fixed costs, not dependent on annual generation, or variable costs which are proportional to generation level. The six cost categories considered here include: Plant Staffing, Maintenance Materials, Plant Supplies and Expenses, including radioactive waste disposal, Nuclear Liability Insurance and Inspection Fees, Interim Replacements, and Administrative and General Expenses.

Plant staffing costs are based on the 225-person plant staff described earlier and assumes a cost of $22,000 per person per year. Maintenance materials are estimated to be 230% of the maintenance staff costs (79 persons) for large LMFBR generation plants and also assumed to be insensitive to plant capacity factors. Thus, they are considered all <u>fixed</u> expenses. Fixed supplies and expenses, which include makeup chemicals lubricants and auxiliary fuels, as well as offsite contract services, radioactive waste management (exclusive of fuel) and nonradioactive waste management has been estimated in the EEDB report to be 5.0 million per year with a variable component of 0.05 mills/kWh. Nuclear liability insurance and inspection fees are estimated at $408,000 per year. Approximately 75% of this amount is for private and Government nuclear liability insurance. Administrative, overhead, and utility home office general expenses, which are associated with the reference facility, are estimated by ORNL to be 15% of the combined staff costs and fixed components of the materials and supplies costs. This compares to 10% of the same costs components for a conventional coal burning facility. The increase primarily results from the larger amount of recordkeeping and safety related administrative cost necessary for the nuclear facility. Table 5-10 summarizes the O&M costs for the reference liquid metal fast breeder reactor facility.

Table 5-10. Annual Operation and Maintenance Costs--1250 MWe Reference Liquid Metal Fast Breeder Reactor Facility @ 70% Capacity Factor

O&M Cost Account	Cost Estimating Relationship	$1000/yr
Plant Staff	225 persons @ $22,000/yr (Fixed Cost)	4,950
Maintenance Materials	Fixed : 79 persons x 22,000 $/yr x 2.3	3,997
	Variable: None	-
Supplies & Expenses	Fixed: Chemicals, gases, lubricants, auxiliary, fuels, etc.	3,100
	Offsite Contract Services	900
	Radioactive Waste Management*	900
	Non-radioactive Waste Management	100
	Variable: $\frac{(.05\text{ mills/kWh})(1{,}250{,}000\text{ kW})(8{,}760\text{ hr/yr})(.70)}{1{,}000\text{ mills/\$}}$	383
Insurance and Inspection Fees	Nuclear Liability Insurance Premiums (Fixed Cost)	308
	Inspection Fees (Fixed Cost)	100
Interim Replacements	Sinking Fund accrual of 30% of direct and indirect plant capital costs at 30 years and 4% interest (Fixed Cost)	5,155
Administrative and General	15% of Staff, Maintenance Materials and Fixed Supplies and Expenses (Fixed Costs)	2,092
	TOTAL O&M COSTS	21,985

At 70% Capacity Factor:

$$\text{Fixed O\&M Costs: } \frac{(21{,}602{,}000\ \$/\text{yr})(1000\text{ mills/\$})}{(1{,}250{,}000\text{ kW})(8{,}760\text{ hr/yr})(.7)} = 2.82\text{ mills/kWh}$$

$$\text{Variable O\&M Costs: } \frac{(383{,}000\ \$/\text{yr})(1000\text{ mills/\$})}{(1{,}250{,}000\text{ kW})(8{,}760\text{ hr/yr})(.7)} = .05\text{ mills/kWh}$$

TOTAL O&M COSTS 2.87 mills/kWh

*Includes materials, packing, 1000 miles transportation and final disposal costs.

Total annual costs for nonfuel O&M are estimated at $21,985,000 or 2.87 mills/kWh for a plant operating at a 70% capacity factor. Almost all of the O&M costs are fixed expenses, 2.82 mills/kWh, with only a small fraction considered variable costs, 1.05 mills/kWh.

7.0 LMFBR FUEL CYCLE

The nuclear-fuel cycle for LMFBRs is shown below. The initial feed materials consist of plutonium (obtained from the reprocessing of fuel from light water reactors) and depleted uranium (which results from the enrichment of the U-235 content of natural uranium). The plutonium would be converted to an oxide (PuO_2) at the reprocessing plant. The uranium, as uranium hexafluoride (UF_6), would be converted to an oxide (UO_2) at the fuel-fabrication plant. Plutonium dioxide and uranium dioxide would be combined at the fuel-fabrication plant and fabricated into mixed oxides for

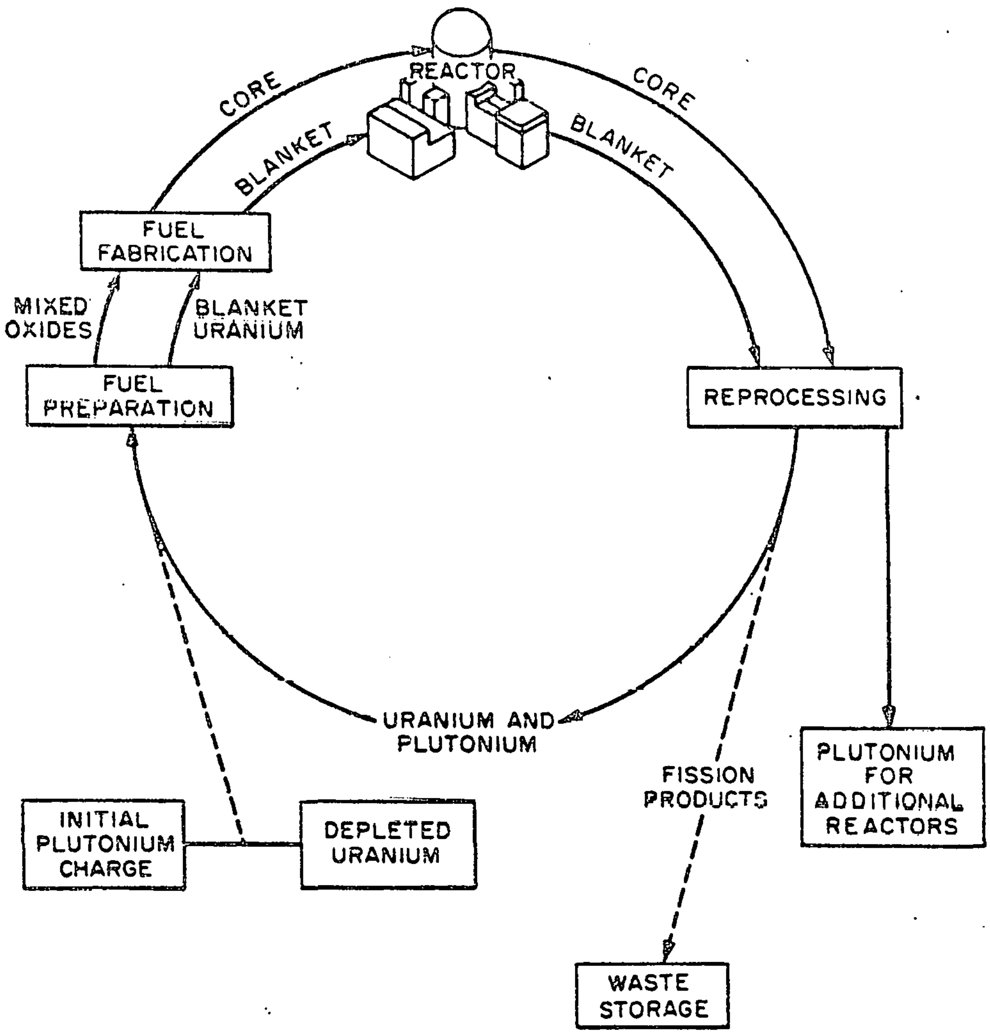


Figure 5-5. Nuclear-fuel Cycle for LMFBR

the core fuel. Uranium dioxide would also be fabricated into pellets for the axial and radial blankets of the reactor. After exposure in the reactor, the irradiated fuels would be stored at the reactor for up to 1 year. After storage at the reactor, the irradiated fuel is shipped in shielded casks to the reprocessing plant, where the plutonium, uranium, and fission products would be chemically separated. The separated fission products would be shipped to a Federal waste-storage facility, and the plutonium would be recycled as fuel. The recovered uranium could be either stored or recycled into the mixed oxide or blanket UO_2. Depleted uranium would be used for makeup for the uranium that is either converted to plutonium in the reactor, lost as scrap in the processes, or stored. A material flowsheet for this fuel cycle is given below.

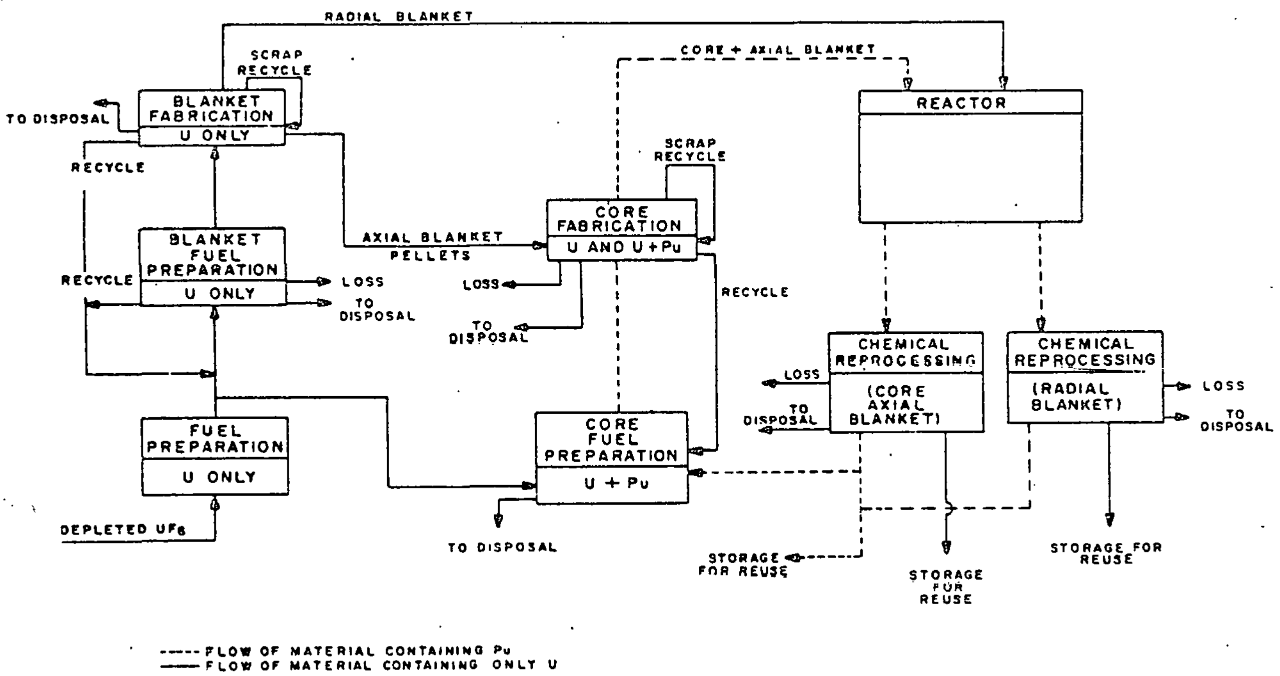


Figure 5-6. Material Flowsheet for LMFBR

The effluents and emissions from the LMFBR fuel cycle would be the same as for the LWR cycle--until the cycle had matured with the reprocessing of the spent fuel. With the mature fuel cycle, the following sections present the only differences (additions) between the LMFBR and LWR cycle.

7.1 AIR EMISSIONS (4, 5)

Chemical	Tons/Yr
SO_x	5.76
NO_x	23.28
HC	.52
CO	.52
Particulates	.63
F^-	.05
Cl^-	6.28×10^{-4}

Radiological	Curies/Yr
Uranium	3.66×10^{-5}
Tritium	1.75×10^{4}
Kr-85	3.92×10^{5}
I-129	2.88×10^{-2}
I-131	.78
Other Fission Products	.17
Transuranics	.02
C-14	23.02

The Purex process is the fuel reprocessing process assumed. In this process, the fuel is dissolved and chemically separated. Airborne effluents normally released from the facility pass through the off-gas treatment and filter systems.

7.2 LIQUID EFFLUENTS (4, 5)

Chemical	Tons/Yr
SO_4	.02
Cl^-	.09
Na^+	.02

7.3 SOLID WASTES (4, 5)

Other than HLW .47 curies/yr

Solid residuals to be disposed of include undissolved fuel element parts.

7.4 WASTE HEAT

The reprocessing of LMFBR fuel results in the generation of 7.32×10^{10} Btu/yr of waste heat for a 1250 MWe facility.

7.5 RESOURCE REQUIREMENTS

Temporarily committed undisturbed area	:	26.2 acres
Temporarily committed disturbed area	:	3.4 acres
Permanently committed	:	.1 acre
Overburden moved	:	104,640 tons

REFERENCES

1. United Engineers and Constructors, Inc., Satellite Power System and Alternate Technology Characterization, UE&C-ANL-790831, 1979.

2. Atomic Energy Commission, Proposed Final Environmental Statement Liquid Metal Fast Breeder Reactor Program, WASH-1535, 1974.

3. Department of Energy, Interim Report on the Performance of 400 Megawatt and Larger Nuclear and Coal-Fired Generating Units, DOE/ERA-0007, 1978.

4. Westinghouse Electric Company, Environmental Report for Operating License, N.R.C.

5. Atomic Energy Commission, "Environmental Survey of the Uranium Fuel Cycle", WASH-1248; April, 1974.

SECTION 6. CENTRAL STATION PHOTOVOLTAIC

6. CENTRAL STATION PHOTOVOLTAIC

1.0 INTRODUCTION

The reference photovoltaic power plant is a nominal 200 MW size. There is no economy of scale beyond the 200 MW size as there is in conventional thermodynamic power plants. The plant characterization provided here assumes that progress in solar cell technology has resulted in high efficiency (19.3%) cells which are fabricated directly to rectangular shape. The cell cost has been projected for the year 2000 to be $\$35/m^2$, which is much less than current costs of about $\$1000/m^2$.

The solar photovoltaic power plant is the earth bound counterpart of the SPS. It uses the same advanced solar cell technology. It does not store energy. Due to the fact that the solar photovoltaic power plant is earthbound, there are differences. The solar photovoltaic power plant on earth has a variable output due to the diurnal sunlight cycle and an erratic pattern of sunlight loss due to bad weather (clouds, fog, haze, etc.). The connection to the power grid on earth is straightforward, involving direct electrical connection.

The solar photovoltaic power plant supplies power to the grid on an "as available" basis. The grid may have storage in the form of batteries, flywheels, superconducting magnets, pumped hydroelectric, or compressed air storage; or it may have virtual storage in the form of hydroelectrical plants which are used for peaking. The grid treats the availability of electric power from the solar photovoltaic plant as a variation in the amount of power which must be supplied from the other sources.

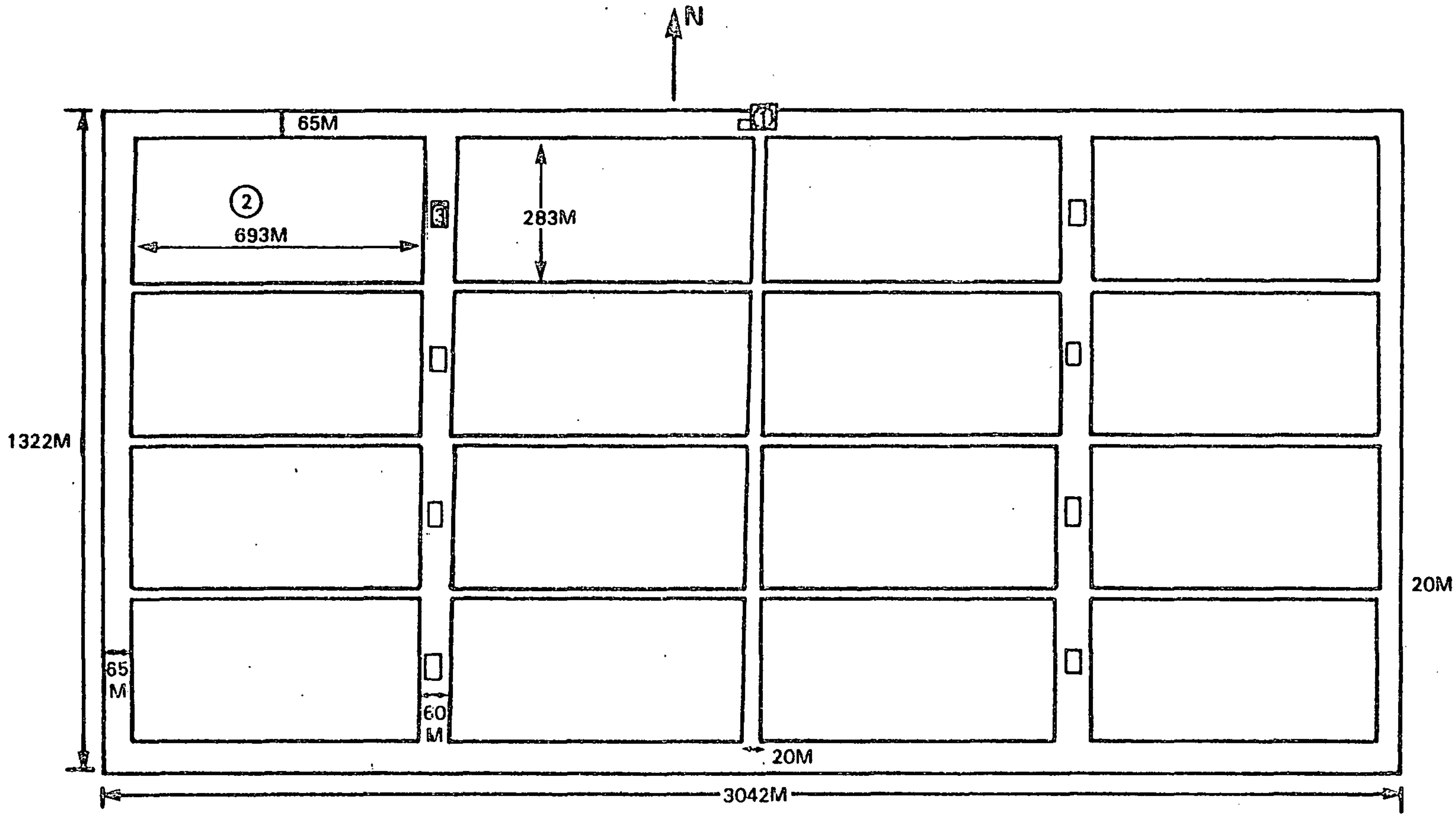
The solar photovoltaic plant uses a large array of solar cells mounted on tilted frames pointed at the sun to generate high voltage d.c. The high voltage d.c. is then converted to high voltage a.c. and fed through transmission lines to the grid, just as any other power plant, operates.

Although large land areas seem to be covered by the solar photovoltaic power plant, the areas normally required for the mining, processing, and transporting of coal for a coal fired plant can be much larger over the lifetime of the plant.

It should be noted that operation of a solar photovoltaic power plant involves negligible environmental impact other than the plant land area.

2.0 GENERAL PLANT DESCRIPTION

The nominal 200 MW Photovoltaic Power Plant requires approximately 4.022 km^2 of land (3042 m E-W by 1322 m N-S). The site includes a fenced-in perimeter setback of 65 m and 8 identical 25 MW modules. These modules are in two N-S rows of 4 modules, each of which is separated by a 20 m access road. Each module consists of two rectangular sectors (693 m E-W by 283 m N-S). A 60 m N-S access and maintenance road separates the two sections and accommodates a 27 m x 55 m converter station. The converter station is comprised of a converter/control building, a switchyard for incoming d.c.-array voltage, and an a.c.-transformer and switchyard to transmit the intermediate voltage a.c. to the Plant Transformer/Control Station. Product electricity from each module is gathered at this central station and transformed to high-voltage power that is compatible with utility line voltages. Plant controls and maintenance activities are housed in a 26 m x 20 m building which is located midway on the northern border of the site. The collected d.c. power and transmitted a.c. power are both underground and routed along the access and maintenance roads. The plot plan is shown in Figure 6-1.



1 Plant Transformer Control Station and Switchyard, Maintenance Building
2 Sector
3 Module Control, Converter, Transformer and Switchyard

Figure 6-1. Solar Facility Plot Plan

3.0 CONVERSION CYCLE DESCRIPTION

3.1 25 MW MODULE

Solar insolation received by the array (100 MW/cm^2 or 0.0929 kW/ft^2, AM1, 28°C) for peak design is reflected (8%), internally consumed (1-1/2%) and absorbed (90.5%). The spectrum absorbed is converted to d.c. electricity with nominal efficiency (19.0%). However, the cells are heated by the solar absorption so that the temperature of the arrays averages 45°C over the year. This reduces the efficiency by 8.4%. Direct current interconnections for cells, panels, and rows have electrical resistance as does the d.c. bus which delivers the energy to the d.c./a.c. converter. At the converter, additional losses are incurred and auxiliary power must be supplied. We have assumed a 2% loss at this site, based upon Figure E-19 and Table E-6 (p. E-38) of the EPRI-ER-685 report (Reference 2), resulting in a net 14.21% efficiency at the converter fence. Table 6-1 illustrates the cycle described above.

3.2 CENTRAL PLANT

The intermediate voltage a.c. from the modules is transported via underground bus to the central station for conversion to high voltage a.c. I^2R losses are incurred in the transmission and step-up transformer. We have assumed a 1.3% loss in efficiency because the referenced EPRI report indicates approximately 0.3% of full load for transmission and a range under 1% for step-up transformer losses. Power at the Central Plant Transformer/Control Station will be, at design conditions, about 197.3 MW at an overall efficiency of 14.02%. Within each module, there are 122,256 panels (61 x 244 cm), each containing 400 silicon photovoltaic cells (6 x 6 cm), for a total of 48.9 x 10^6 cells per module or approximately 391 x 10^6 cells per plant. The panels in each sector are adjoined in three rows of 283 E-W with 72 parallel rows N-S, tilted south nominally 30° from the horizontal on the 244 cm edge. The parallel rows are separated by approximately 2.32 m to minimize shadowing. The panel and row arrangement is shown in Figure 6-2.

Each vertical set of three panels are connected in parallel and 283 files of 3 panels are in series to form a row which is in series with the adjacent row to form $\pm$ 4809 V. Thirty-six pairs of rows are in parallel to form a sector. Two sectors are parallel to form a module.

Cells on the panels and panels on the array are connected in series across the array from east to west, and parallel-connected up the array from north to

Table 6-1. 25 MW Solar Photovoltaic Central Plant Array Parameters*

Parameter	Silicon Cell	Solar Panel	Series Row	Sector	Module
Size (Area)	6 x 6 cm	61 x 244 cm	693m x 1,845m	(693m x 283m) = .196 km^2	(1447m x 283m) = .4095 km^2
Cells	1	400	339,600	24,451,200	48,902,400
Panels		1	(3 x 283) = 849	61,128	122,256
Rows			1	72	144
Sectors				1	2
Modules					1
Output at 100 MW/cm^2, (45°C)					
Current (Amperes)	1.24	12.4	37.2	1,339.2	2,598.4
Voltage	.458	17.349	4.81K	±4.761K	±5.25K (a.c.)
Power (Watts)	.56792	215.128	178.8K	12.75M	24.988 MW
Efficiency					
Item Efficiency	15.77549%**	94.7%	98%	99%	98%
Inefficiency Source	Basic Cell-Cover Glass	Panel Wiring & Blocking Diodes	Interpanel Connectors & End Wiring	Inter-row buses	d.c./a.c. Converter
Cumulative Efficiency	15.78%	14.91%	14.64%	14.49%	14.21%

* (Modeled somewhat after Table K-2 Pk-15 EPRI-ER-685)

** Solar Cell Efficiency 19.03% Bare at AM1 (28°C)

Total Module Cell Area = .176 km^2
Panel Area = .182 km^2

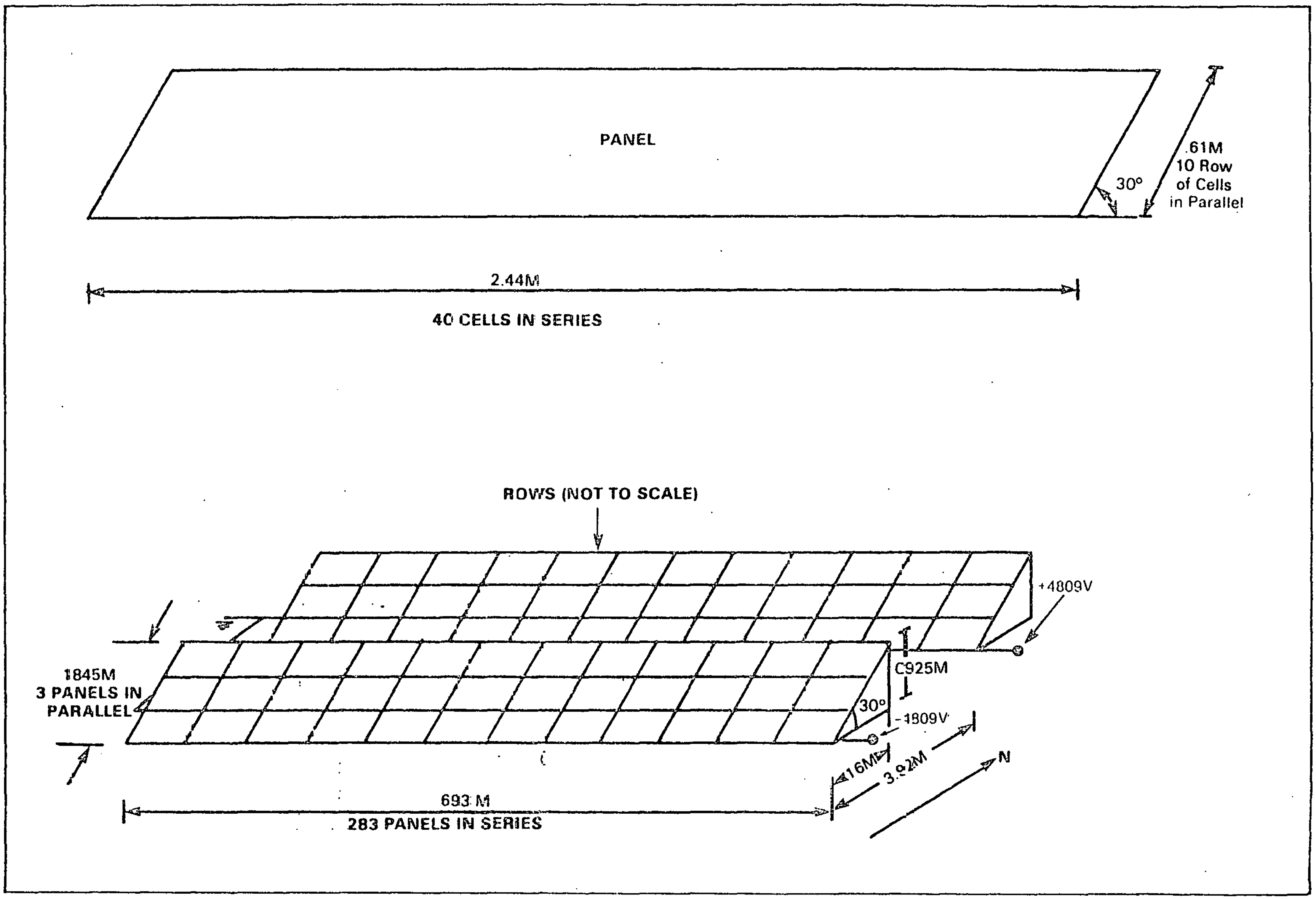


Figure 6-2. Solar Panel Arrangement

south. This arrangement minimizes interrow shadow effects. The upper shadowed series cells and panels always develop full voltage. Shadowed parallel strings on the lower edges of the array reduce the available current.

A nominal 30° tilt facing south has been assumed for the array. The actual tilt chosen for a specific location would be equal to the latitude value in degrees, approximately 10 degress less to maximize annual energy collection. With the 30° tilt and a shadow spacing factor of 2.12 to minimize interrow shadowing, a row-to-row pitch distance of 3.92 meters is established.

The electrical and physical parameters selected and calculated above provide the central framework for a conceptual design.

Panel and cell insulation materials and values have been assumed to be adequate at the end points of the series string with voltages of ± 4809. It has been assumed that the lightning protection system (an array of lightning rods) will not shadow the solar cells from the sun. Diodes in panel and array circuitry provide protection against possible open and short circuit conditions. Panel/array short circuit and grounding provisions are included for personnel safety during servicing and installation. Sizing, spacing, interconnection requirements, wire length, and size have been analyzed to ensure maximum performance/cost effectiveness.

3.3 ELECTRICAL SYSTEM DESCRIPTION

The 200 MW plant consists of 8 identical modules containing an a.c. output which is collected at a common switching station and transformed from medium to high voltage to match the utility transmission voltage. Each module is divided into three major levels or subsystems: (1) the array and its connecting cables and main d.c. bus, (2) the converter station, and (3) the medium voltage cable. The switching/transformer station is common to all 8 modules, each rated at 25 MWe.

A d.c. circuit breaker is provided at the d.c. input terminals of the converter station. This is the only electrical equipment (excluding the array and cells) that requires development effort. The d.c. breaker is used for start-up and shut-down sequencing, and for protection from faults in the converter, array, bus, or cable. High impedance ground detectors detect a ground fault in the array subsystem and initiate protective circuit interruption and annunciation of the fault. Reactors are used to smooth the d.c. current and reduce the ripple caused by converter commutation. Thus, harmonics on the d.c. side are confined to the converter station or reduced to a low value in the array bus and interconnections. The converter valve assembly, together with the converter transformers, is a 12-pulse bridge connected line-commutated inverter arrangement. The load tap changer on the converter transformer is used to keep the inverter within reasonable firing angle margins for the range of operating voltage expected from the array during the wide variations in the load and in array temperature. The converter transformer rating is less than the peak output of the converter since the insulation follows a predictable cycle which permits "underrating" the transformer by taking its thermal inertia into account.

High-pass filters provide higher order (60 Hz) harmonic suppression and power factor correction. At full load, the plant operates at .9 power factor. The total filter requirement is deployed in two (or three) groups to give stepped var (reactive volt-amperes) control, and reasonable power factors at light loads. An auxiliary transformer at each converter station taps converter station and array auxiliary power. The transformer is tapped to the medium voltage station bus ahead of the load break disconnect to provide auxiliary power independent of the converter operation. The most economical voltage rating for the 25 MW module size medium voltage cable was determined to be 34.5 kV. The cable is installed in underground ducts and consists of three shielded, jacketed, single-phase conductors, plus a ground wire.

For economic reasons, a simplified 34.5 kV single bus, radial switching arrangement is chosen at the transformer switching station. Similarly, the single step-up transformer is a triple-rated 100/132/168 MVA OA/FA/FOA transformer that takes advantage of the transformer's thermal inertia and the predictable maximum plant load curve.

The plant electrical boundary was assumed to be the high voltage terminals of the step-up transformer. Rather than rely solely upon the single circuit high voltage (HV) transmission circuit for plant auxiliary power, a 34.5 kV feeder reserve source is shown. Because a utility reserve source may not be practical, considering the plant's remote location, some kind of local standby source will be required.

4.0 ENVIRONMENTAL IMPACTS OR RESIDUALS

4.1 AIR

Under normal operating conditions, no emissions are expected. A fire in the electrical transmission could release toxic materials, but such components are no different from those used in other power stations. The large land area of the solar station provides a separation between these components and thus would limit the extent of a fire. The toxic material (combustion products) which is released would thus be in smaller quantities than if the fire were in a conventional power station.

4.2 WATER

The requisite periodic cleaning of the array surfaces creates minor water runoff problems. However, containment of the cleaning agent prevents surface or sub-surface water contamination, and proper site preparation and choice of contours and cleaning material should minimize this concern.

4.3 SOLID WASTES

Beyond minor solid wastes created by panel breakage replacements, no solid wastes are expected to be generated. These waste materials consist of glass, silicon cells, aluminum backing, and minor amounts of sealant and substrate.

4.4 THERMAL EMISSIONS

The massive arrays designed to absorb as much insolation as possible may have some minor effect on daily cycles of heating/cooling from absorbed insolation relative to bare or cultivated ground, but they should not have any noticeable favorable or unfavorable impact.

4.5 REFLECTED INSOLATION

The reflected insolation has been estimated at some 8% (less than expected without the plant). However, the concentration of reflection by the array, as opposed to diffuse reradiation from unimproved land, could potentially be a hazard or nuisance in the early morning or late afternoon during the summer. This reflectance has been compared to reflection from a still lake or from glass in a vertical building, a minimal hazard generally acceptable to the public.

4.6 LAND USE

The most significant impact of a 200 MW Central Power Plant will be the removal of land from other use. As indicated earlier, some 4,022 km^2 of land must be converted from other uses to serve as a platform for solar arrays, or a rounded 20 km^2/GW. A coal-fired controlled emission power plant is estimated to require 3.885 km^2/GW but this excludes any extraneous land use such as mining processing and transporting which could require as much as 66.3 km^2 (EPRI, p. N-27). A gas turbine single cycle generating facility can require only 1.3 km^2 for 1 GW of capacity.

5.0 CONSTRUCTION AND OPERATING CHARACTERISTICS

The 200 MW, nominal, Central Plant Solar Photovoltaic Electrical Production System (CPS) is hypothesized as a flat-plate collector, nonstorage, contributor to the utility system grid.

5.1 CONSTRUCTION

This mammoth-size installation is projected to require 5 years for construction before going on stream (Reference 2). It is believed that any utility (and regulatory commission) would phase in partial capacity as it was completed, particularly with 8 identical modules that could stand independently. Given that a utility must add capacity, a 5-year wait would require other expansions that would reduce capital availability for this project. Therefore, a gradual construction program will consist of land purchase, site clearance, and road and other site construction for the central station in the first year (1995). The next four years will involve installation of 25% of the final capital equipment each year. Thus, 25% of plant capacity will be available at the end of year two, 50% at the end of year three, and so on. The complete output of the plant would thus become available at the end of the fifth year, January 1, 2000.

There do not appear to be any problems. However, we are not familiar with lead times, specifically the necessary converters and transformers required for production of sufficient cells. Early operation would generate cash flow, minimize AFDC, and minimize escalation. The first 25% capacity increment will function as a process demonstration unit, which will alleviate subsequent problems. It will also function as a training center for personnel. There will be a center for construction, and operating and maintenance practices as well. The levelled construction would, moreover, minimize the impact of high-cost, high-density progress normally found in a large project. The installation of panelized solar-arrays, at ground level, on shop-fabricated tilt-angle supports, and with simplified efficient interconnection plugging would be a simple project. The underground wiring and converter/transformer installations are also a standard "non-novel" activity and should pose no problems.

5.2 OPERATIONS AND MAINTENANCE

Designed without dedicated storage, the function of this plant is to maximize electric power generation, i.e., achieve the highest possible lead factor. EPRI (Reference 2), via GE, believes that a 3-man crew/shift plus a 2-shift technician, and 3-man daytime staff will be used for a 200 MW plant. They also indicate that 180 additional man-weeks would be required for maintenance of the "balance of plant." The shift crews are responsible for array maintenance requirements.

For our purposes, we would suggest the following staffing (to include both O&M).

Staff - 200 MW CPS Solar PV

	Shift			
	1st	2nd	3rd	Total
Manager	1			1
Shift Superintendent - Operations	1	1	-	2
- Maintenance	1	1	1	3
Operators	1	1	-	2
Maintenance Men	2	2	3	7
Technician	1	1	1	3
Engineer	1/2	-	-	1/2
Clerk/Typist, etc.	1	-	-	1
Swing-men*	2	2	2	6
	10-1/2	8	7	25-1/2

*To ensure 7-day operations and maintenance

5.2.1 Maintenance of Arrays

PV power plant maintenance is unique with respect to the photovoltaic arrays: maintenance of reflectors, refractors, and solar panels is an uncertain area. For flat-plate panels, the encapsulation itself provides protection to the cells, but the encapsulation surface will require cleaning. The required frequency of cleaning can only be determined through experience with actual arrays in different climates, but it will probably be necessary to accept some loss of transmittance or reflectance of the collectors to achieve a feasible maintenance schedule. For large arrays, it will undoubtedly be necessary to develop vehicles which can pass between the collector rows to perform the cleaning with water sprays or mechanical brushing techniques. Array support structures will require periodic painting and cleaning for corrosion prevention.

We have somewhat expanded the postulated staff because we believe that 8 modules, each with .176 km^2 of array, to be cleaned and maintained (requiring

208 km of traveling to go through the rows in each module), will call for more sizeable housekeeping. If anything, the maintenance force could be expanded to include structure, converter, and switching upkeep. Each quarterly cleaning/rinsing of the arrays (as suggested by Westinghouse) would require a 7-day/week, 365 day/year average of 18 km/day or almost 11,000 panels on a daily continuous basis.

5.2.2 Balance-of-Plant Maintenance

For the portion of a PV plant excluding array and array support subsystems, the maintenance effort will be relatively standard by utility criteria. The main difference compared with conventional plants will be that maintenance activities of this plant relate more closely to those of transmission and distribution facilities. The plant has a transmission/distribution character because it is deployed over a large area and has similar major elements. In addition, since array maintenance and repair is possibly a nighttime activity, array and roadway lighting with attendant lighting system maintenance requirements is very likely.

Routine testing and preventative maintenance will be performed on a scheduled basis; fault correction and component and equipment repair and replacement will be performed as required. These plants employ passive cooling of the arrays because of the nature of the plant electrical equipment (solid state converters, conventional cables, transformers, switchgear, and auxiliary equipment), and therefore require a relatively low level of maintenance.

6.0 COST CHARACTERIZATION (TERRESTRIAL PHOTOVOLTAIC)

Capital cost estimates for the 200 MWe reference Central Power Station - Solar Photovoltaic Facility represent composites of cost data found in several authoritative sources and from information regarding silicon cells of SPS Concept Development documents. The designated silicon photovoltaic cells are patterned after Comsat nonreflecting cells and are valued at $\$35/m^2$. The balance of costs for the array and connecting conduits was developed based upon detailed cost data for a larger but similar system contained in the GE report, Reference 1. Power conditioning and electric plant equipment costs are estimated based on data for a similar flat-plate system in the EPRI/GE report. Indirect costs were also derived from relationships exhibited in the EPRI/GE report.

As described in the cost characterization for other facilities, certain costs have been specifically excluded from the base cost estimates. These costs, which are sensitive to (1) the specific utility policies and preferences, (2) the particular location, and (3) the prevailing economic attitudes and environment, include:

- Owner's Costs - Consultants, site selection, construction inspection and management, etc.
- Federal, State and local permits, fees and taxes
- Allowance for funds used during construction
- Price escalation during construction
- Allowances for contingencies
- Owner's working capital, inventory items

6.1 DIRECT CAPITAL COSTS

The capital costs for a 200 MWe Central Power Station/Solar Photovoltaic Facility found in Reference 2 have been appropriately adjusted to reflect the improved performance and cost characteristics of the silicon photovoltaic cells assumed in this report. The square silicon cell used herein (6 cm each side) is projected to generate 0.568 Watts at a voltage of 0.458 d.c. and current of 1.24 Amps, at an overall efficiency of 15.76% from a cell efficiency (at 28°C) of 19.0% and cover-glass attentuation of 9.5% and high temperature voltage loss of 8.4%. After allowing for wiring and conversion losses, the net efficiency into the utility transmission system is projected to be 14.02%. The previously cited EPRI report used a nominal 12% silicon cell efficiency, which represented a conservative state-of-the-art at that time. Additionally, the projected cost parameter for silicon cell technology has been modified to cost $\$35/m^2$ of silicon cells, which is consistent with assumptions made for the SPS system.

The costs of solar array panels and supporting structures were derived from the detailed structural estimates found in Reference 1. On the basis of silicon cell area relationships, these costs were adjusted to more accurately indicate the required investment for the reference system.

Power conditioning equipment and other electric plant equipment costs are essentially derived from updating the EPRI report, with a comparison of costs included in the GE Reference 1 for corroboration.

The base direct capital costs, Table 6-2, include the costs of all materials, equipment, components, and installation labor necessary to construct the 200 MWe Solar Photovoltaic Facility on the purchased 994 acre site. The direct capital costs were assembled from the various data and updated to depict costs as of January 1, 1978, through use of 1.1365 escalation from mid-1975 and 1.0823 for mid-1976 calculated as the ratio of fourth quarter 1977 to yearly average numbers for the GNP Implicit Price Deflator index.

Direct craft labor costs were not explicitly detailed in any of the references. However, these may be estimated based on the relative fraction of labor for similar types of construction activities for other technologies. For example, labor costs make up roughly 40% of the total cost of buildings and facilities, and electrical plant costs in a coal facility. If 40% of the buildings and facilities costs, power conditioning costs, and electrical plant costs are assumed to be for labor, and if the array installation cost noted under account 22 is taken as labor, the total labor cost would be estimated at $22,276,000 or about 1.7 million man-hours.

6.2 INDIRECT CAPITAL COSTS

Indirect capital costs associated with any construction project will include construction management and services, field engineering and supervision, and home office design engineering, equipment logistics, and services.

Table 6-2. Estimated Direct Base Construction Costs 200 MWe Solar Photovoltaic Central Power Station (in January 1, 1978 dollars)

Account Number	Construction Needs	200 MWe Costs ($1000)
20	Land and Land Rights 994 A @ $4,480/A	4,453
21	Buildings and Site Facilities (a)	
	1. Site Development (a)	2,584
	2. Structures	160
	3. Towers	240
	4. Underground Conduit	1,250
	5. Underground Conduit	1,150
	Total Buildings and Site Facilities	5,384
22	Solar Array Equipment	
	1. Silicon Solar Photovoltaic Cells @ $35/m^2$	48,294
	2. Photovoltaic Array Structures	25,250
	3. Array Installation	11,600
	Total Solar Array Equipment	86,144
23	Power Conditioning Equipment (b)	10,823
24	Electric Plant Equipment (b)	10,390
	TOTAL DIRECT CONSTRUCTION COSTS (c)	117,194

NOTES

(a) GE (in Reference 1), from ratio devel./site, derived at $2600/A-Other materials per GE details Tables K-11, K-14, K-12

(b) EPRI, ER-685 (Reference 2), Table G-5, p. G-7, escalated x 1.0823 (1976 average to 1-1-78 GNP Deflator)

(c) Miscellaneous Plant Equipment (Acct. No. 25) included in Account Nos. 21, 22, 23, 24. Labor costs are contained in account totals and estimated to be 1.7 million man-hours or $22,276,000.

Typically, these represent an estimated value of services performed and are derived from consideration of the total direct capital costs and labor costs involved in the project.

Costs for construction services (Account 91) were estimated based on temporary construction facilities valued at 8% of the total plant costs, and payroll insurance and taxes valued at 15% of the direct labor costs. These factors result in a total construction services cost of $12,737,000.

Home office engineering and services has been estimated to be 4.3% of the direct plant costs--similar to the fractional cost displayed in fossil fuel plant construction. Likewise, field office engineering and services was estimated at 3.6% of the direct plant costs. Table 6-3 itemizes the indirect cost estimates which total nearly $20 million or about 17% of the plant's direct capital costs.

Table 6-3. Estimated Indirect Capital Costs for 200 MWe Solar Photovoltaic Central Power Station (in January 1, 1978 Dollars)

Account Number	Construction Needs	Reference Design Costs ($1,000)
91	Construction Services	10,716
92	Home Office Engineering and Services	5,050
93	Field Office Engineering and Services	4,228
	TOTAL INDIRECT CAPITAL COST	19,994

6.3 OPERATING AND MAINTENANCE EXPENSES

The basic 200 MWe plant configuration used as a model for this characterization cited an operating staff of 14 people and a maintenance requirement of 180 man-weeks of effort. To ensure full, uninterrupted operations and requisite 24 hr/day maintenance, we plan to use additional maintenance personnel and swing shift operators. The staffing costs are estimated at an average of $22,000/man-year.

Operating supplies necessary to sustain day-to-day operations were estimated to cost 15% of the direct operating payroll. This is a common cost estimation practice. It represents office supplies, telephone and other customary expenses of operations. Maintenance supplies are established at 60% of the maintenance payroll and will include cleaning supplies, tools and equipment replacements, and parts and materials used in performing the necessary routine maintenance.

During the 30-year life of this project, equipment will break down and array structures will be damaged. An allowance must be considered for these intervening replacements. As used in the coal gasification/combined cycle characterization, a sinking fund will accumulate to 30% of total investment over the 30-year life to cover these expenses. The annual payment to the sinking fund is $783,000/year.

As part of an existing utility, the reference facilities will have administrative and service function costs allocated to operations. These amount to 10% of payroll and supplies and account for administrative, personnel, legal, accounting, and other services incident to operations.

Phoenix, Arizona and Cleveland, Ohio are two examples of sites used in this review. (Boston, Massachusetts is the third example.) The sum of O&M costs above has been assumed identical for each location. However, the cost per kilowatt hour of electricity produced will be substantially different because the two locations will vary in their net output of power. The widely differing insolation and climatological characteristics inevitably force differing plant operating factors for each location. Phoenix was carefully studied in the EPRI report and calculations resulted in a plant operating factor of 25.8%, i.e., over the 8760 hr/yr. Phoenix's solar photovoltaic output represented some 25.8% of that time or equivalently 2260 hours at design capacity. Unit costs of 3.8 mills/kWh ($0.0034) for O&M costs were derived on that basis.

Boston, which was also included in the report, had a calculated plant operating factor of 17.7%. Insolation at the three cities is known and expressed normally in Langleys which is defined as gram-calories per square centimeter or 3.687 Btu/ft^2. Cleveland, the other site considered, was not included in the EPRI report. To derive the estimated plant factor for Cleveland, the following interpretation was used:

Given: P.O.F.* is a function of insolation

P.O.F. - Phoenix 28.8%

P.O.F. - Boston 17.7%

Langleys, Mean daily, - Phoenix 518

Boston 301

Cleveland 335

To Find: P.O.F. - Cleveland

1. $\frac{\text{Phoenix}}{\text{Boston}} = \frac{25.8\%}{17.7\%} = \left(\frac{518}{301}\ \text{Langleys}\right)^{K}$

2. $\text{Cleveland P.O.F.} = \left(\frac{335}{301}\ \text{Langleys}\right)^{0.695} \cdot \quad \times\ 17.7\%\ \text{Boston P.O.F.}$

$\text{Cleveland P.O.F.} = 19.1\%$

*P.O.F. - plant operating factor

The annual O&M cost for solar photovoltaic power generation in Cleveland is estimated, on this basis, at 5.1 mills or $0.0051/kWh. Table 6-4 illustrates the estimated annual operational expenses.

Table 6-4. Estimated Annual Operating and Maintenance Costs 200 MWe Reference Solar Photovoltaic Central Power Station (in January 1, 1978 dollars)

O&M Account	Operating Cost Components	$1,000/Yr
Plant Staff	25-1/2 persons @ $22,000/yr (Fixed Cost)	561
Supplies & Expenses	Operating @ 15% Oper. Payroll Maintenance @ 60% Maint. Payroll	28 224
Interim Replacements	Sinking Fund Accrual of 30% (Direct & Indirect Capital Costs over 30 year life at 4% "real" interest rate	783
Admin. & General	10% of payroll plus supplies	82
	TOTAL ESTIMATED O&M COSTS	1,678
Unit O&M costs in mills/kWh		
Phoenix	(445,914 MW hr/yr) (a)	3.8
Cleveland	(330,114 MW hr/yr) (b)	5.1

NOTES

(a) Phoenix plant capacity factor = 25.8% per Table H-1, p. H-2, EPRI ER 685, Reference 2.

(b) Cleveland plant capacity factor = 19.1% from interpolation, Table H-1 for Boston/Phoenix, Reference 2.

$$\frac{\text{Phoenix}}{\text{Boston}} = \frac{25.8\%}{17.7\%} = \left(\frac{518}{301}\right)^{0.695}$$

$$\left(\frac{\text{Cleveland}}{\text{Boston}}\ \text{Langley/day}\right) = \left(\frac{335}{301}\right)^{0.695} \times 17.7 = 19.1\%$$

REFERENCES

1. "Conceptual Design and System Analysis of Photovoltaic Systems, Final Report, Volume II Appendices, Report No. ALO-3686-14." General Electric, Space Division. March 19, 1977.

2. "Requirements Assessment of Photovoltaic Power Plants in Electric Utility Systems, ER-685, Volume 2, Research Project 651-1." General Electric, Electric Utility Systems Engineering Department. June 1978.

SECTION 7. MAGNETIC CONFINEMENT FUSION

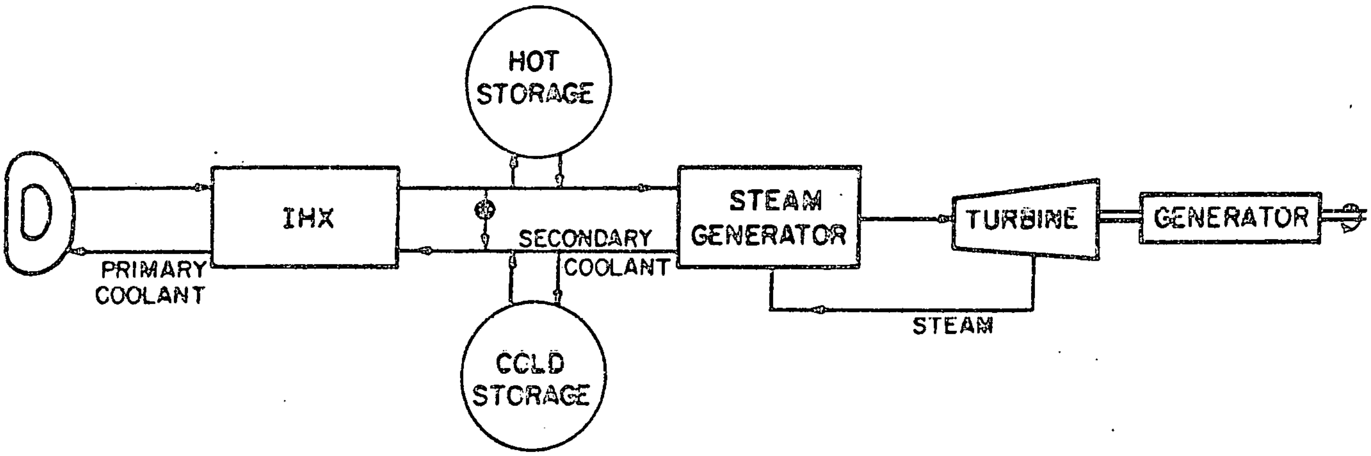
7. MAGNETIC CONFINEMENT FUSION

1.0 INTRODUCTION

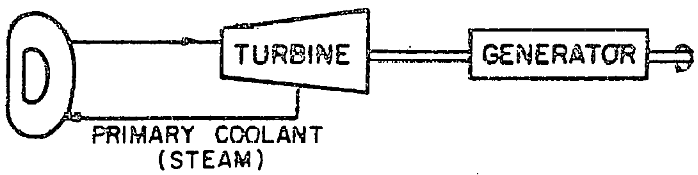
The characterization of a fusion power plant presented here is based on the NUWMAK power plant design developed by the University of Wisconsin Fusion Engineering Program of the Nuclear Engineering Department and published in March, 1979. The NUWMAK power plant produces electricity through a boiling water reactor (BWR) power cycle with heat supplied by a Tokamak fusion reactor. One plant produces 660 MWe net. The power facility characterized here consists of two NUWMAK reactors and produces a net power of 1320 MWe operating at an overall thermal efficiency of 31.5%.

The NUWMAK is a newer and more realistic design than the UWMAK series developed by the University of Wisconsin. The design philosophy in NUWMAK has been to make mechanical design and maintainability easier. The power density in NUWMAK is increased to about 10 W/cm^3 as compared to 0.5 to 2 W/cm^3 in earlier designs. The NUWMAK design does not use a divertor to control impurities, thereby considerably simplifying the reactor design and allowing easier access and maintenance. Instead, impurity control in NUWMAK is achieved through a system using gas puffing (which also serves to partially fuel the reactor). Heating of the plasma is achieved via radio-frequency (RF) heating rather than by neutral-beam injection, simplifying the engineering. The reactor blanket employes phase change energy storage, reducing the need for and simplifying external energy storage systems. Titanium alloys replace stainless steel as structural materials for the first wall and blanket of the reactor, in order to increase material life under neutron bombardment and reduce the impact on mineral resources.

Figure 7-1 shows schematically the simplification in the power cycle of NUWMAK as compared to a "conventional" Tokamak power plant. Although many technical questions remain concerning the NUWMAK design, the NUWMAK design is an improvement over earlier fusion reactor designs.



POWER CYCLE FOR A CONVENTIONAL TOKAMAK



POWER CYCLE FOR NUWMAK (BWR TECHNOLOGY)

Figure 7-1. Comparison of Power Cycle of NUWMAK to a Conventional TOKAMAK Reactor

2.0 GENERAL PLANT CONFIGURATION

An overall plant layout for two 660 MWe NUWMAK reactors is shown in Figure 7-2 with one reactor building layout shown in Figure 7-3. The functions of each building are briefly described below:

- A Reactor Building houses the reactor and other components of the nuclear island, providing primary containment.
- Two auxiliary buildings contain equipment to handle radioactive material, the tritium handling system, and other auxiliary equipment needed near the Reactor Building.
- A Hot Cell receives and processes irradiated blanket and other reactor components, providing temporary storage for these materials.
- A Radwaste Building processes all of the radioactive waste from the tritium handling and coolant purification systems.
- A Turbine Building contains the turbines and associated equipment (steam drums, condensers, etc.).
- A Maintenance Building contains the equipment needed to maintain the radioactive components of the reactor.
- An Administration and Control Building is located separate from the Reactor Building complex.
- Energy Storage, Invertor, and Miscellaneous Buildings house the remaining equipment and facilities.

The fusion plant generates electricity using deuterium obtained from heavy water and tritium, which (after initial fueling) is generated from lithium conversion in the reactor blanket. The blanket design is unique, using a breeding material which will operate at its melting point, thereby storing energy. The reactor is a Tokamak operating cyclically at a duty factor of 0.91 with energy stored in the blanket. Boiling water is used to transfer the energy from the reactor blanket to the turbines, eliminating the need for two coolant loops (as in the UWMAK designs). Existing Boiling Water Reactor (BWR) technology can be used for the power cycle.

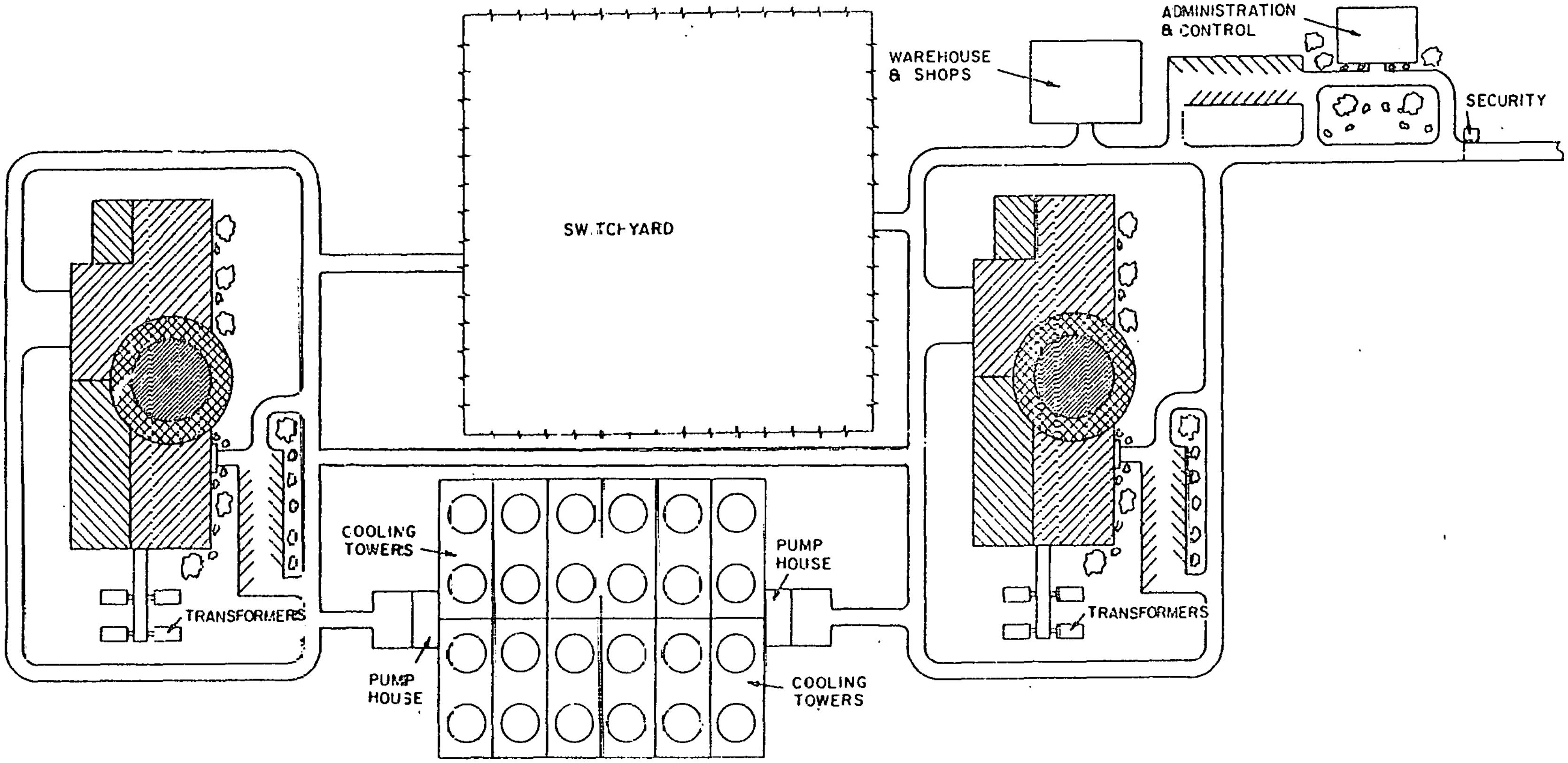


Figure 7-2. Overall Plant Layout for Two 660 MWe NUWMAK

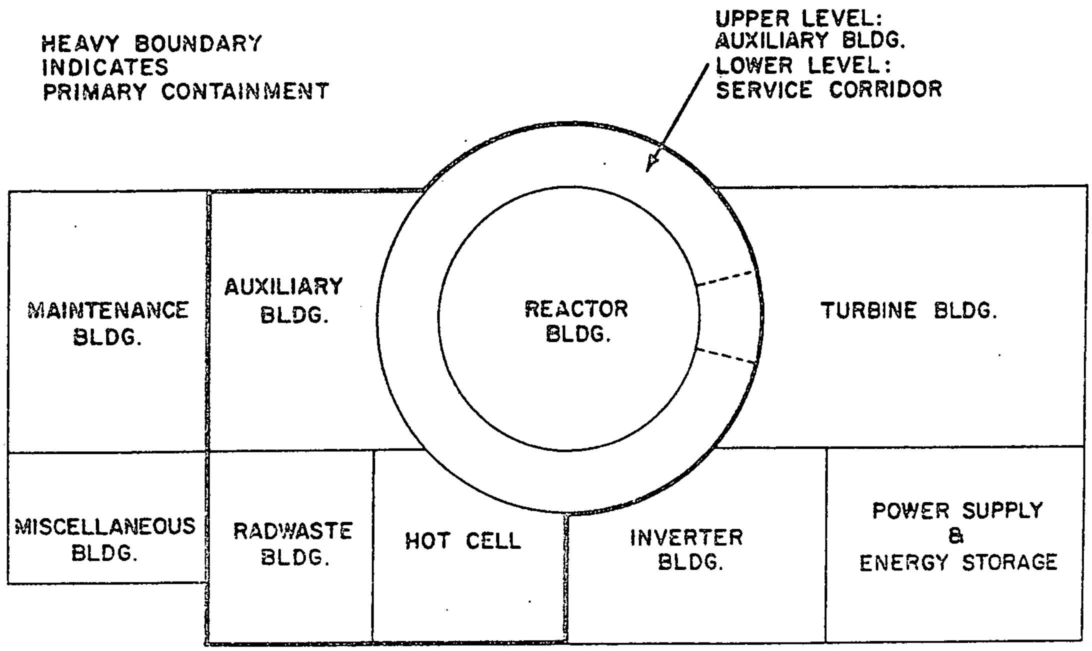


Figure 7-3. NUWMAK Reactor Building Layout

Apart from the normal cooling tower discharges, there are two environmental residuals that need to be controlled. The first is tritium. Tritium is a primary fuel and is radioactive (beta emitter). The Reactor Building is hermetically sealed so that at ambient air temperatures the tritium diffusion rate is relatively slow enabling tritium scavenging systems to keep radioactive fluid emission to less than 1 curie/day. The other source of radioactivity is from replacement of blanket modules which have become radioactive through neutron activation. The use of titanium alloys for structural material significantly reduces the problem since these materials should have longer lives under neutron bombardment than stainless steel and have less residual radioactivity (except after very long times). First wall life is estimated as 10 years.

3.0 THERMODYNAMIC CYCLE CHARACTERISTICS

The reference fusion plant uses deuterium-tritium fuel. During the reactor burn cycle the deuterium (D) and tritium (T) exist in the torroidal reactor chambers in a plasma state. When a D-T fusion reaction occurs, a helium 4 nucleus (alpha particle) is formed and a neutron is given off. This reaction and energy balance is shown in Figure 7-4.

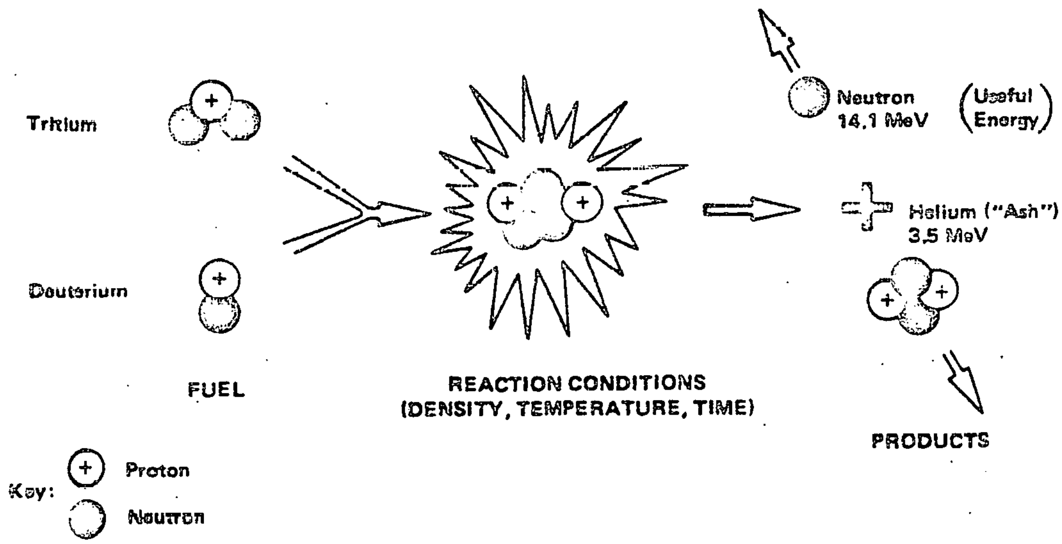


Figure 7-4. Deuterium-Tritium (D-T) Fusion Reaction

The high-energy neutrons produced are absorbed by a blanket which surrounds the fusion reaction chamber. The neutrons heat the blanket and then this heat is removed from the blanket and used to produce electricity. NUWMAK uses boiling water as a coolant and a conventional boiling water reactor (BWR) power cycle to produce electricity.

The power flow for one NUWMAK reactor is shown in Figure 7-5. The gross thermal efficiency is 34.5%. After accounting for auxiliary power requirements of 65 MW and cooling of the magnets of 60 MW, the net power output is 660 MWe with a net thermal efficiency of 31.5%. Two reactors would have a net output of 1320 MWe.

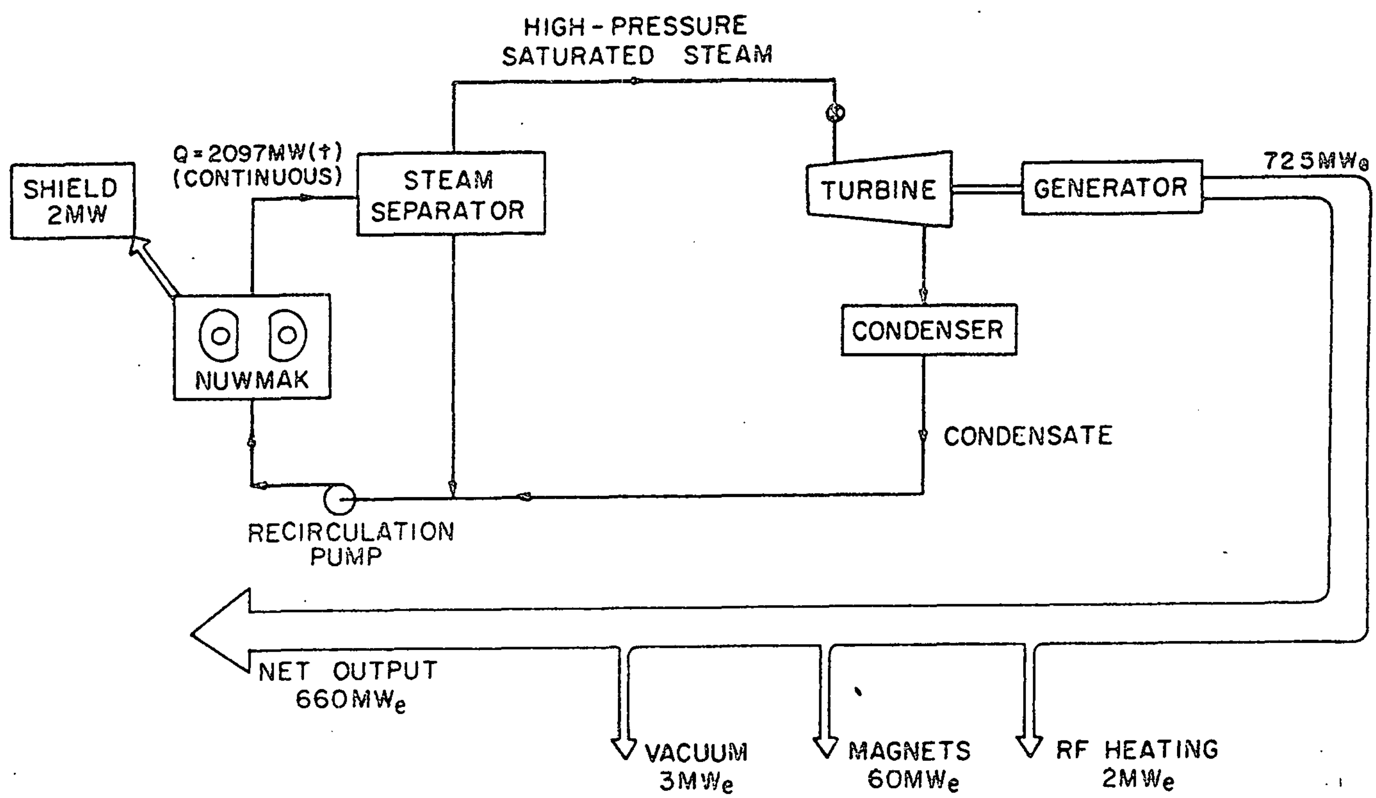


Figure 7-5. Power Flow Diagram for NUWMAK

3.1 FUSION REACTOR

The controlled nuclear fusion reactions which supply the heat to the blanket coolant system are not simple to produce. In fact, scientific break-even (energy output from the reactions equal to energy input to produce the reactions) has not yet been achieved. Sustained fusion reactions require a plasma with very high temperature and high density, confined sufficiently long. In a NUWMAK reactor, the plasma will be initially heated by ohmic (resistance) heating and with radio frequency (RF) waves and contained by strong magnetic fields. The reactor is a Tokamak type, in which the plasma is contained in a toroid. A cross section of one reactor as cut through a toroidal field (TF) coil is shown in Figure 7-6. The plasma is contained in "D" shape at a density of about 3.1 x 10^{14} ions/cm^3.

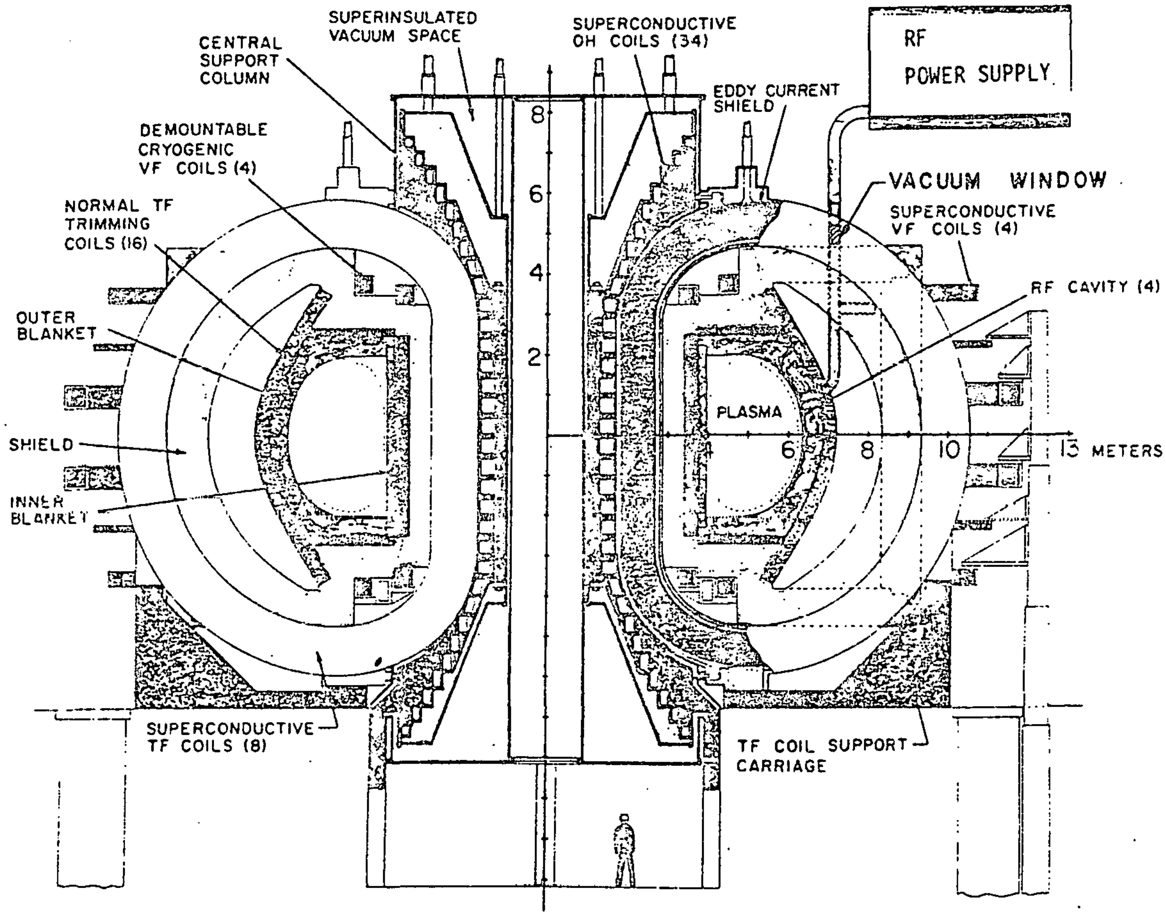


Figure 7-6. Cross-Sectional View of NUWMAK

The NUWMAK reactors differ from those of previous studies (such as UWMAK) in that no divertor is used. Impurity control (which is needed in order to keep the plasma from cooling) is accomplished instead by gas puffing. The gas puffing, along with partial pellet fueling, permit operation for approximately 225 seconds with adequate plasma cleanliness. During a burn, neutral deuterium gas is puffed into the plasma periodically with a time between puffs of about 0.5 seconds. Tritium is introduced in solid pellets, which penetrate only the outer plasma mantel. A sharp temperature profile develops at the plasma edge which is maintained cold by both the gas puffing and by impurity introduction. However, the step temperature profile prevents impurities from diffusing towards the plasma center. The impurities are neutralized and pumped out through vacuum pump ports.

The plasma requires a magnetic field of 6.05 tesla at a major radius of 5.13 meters, which means a maximum field of 12 tesla at the magnet. To provide the needed access for maintenance and repair, NUWMAK is designed with only eight large superconducting "D"-shaped TF coils and the increased ripple is corrected with 16 saddle-shaped trimming coils. The primary design of the TF coil uses NbTi superconductor with subcooled superfluid liquid helium at 1.8°K and atmospheric pressure. There are four cryogenic vertical field coils inside of the TF coils and four superconducting coils at the outside of the TF coils to maintain the elongated plasma. The ohmic heating coils are located inside the central core of the reactor system. Since the magnets require a pulsed power supply, each reactor is supplied with a two MWh superconductive energy storage unit.

Since ohmic heating is effective only at relatively low plasma temperatures, auxiliary heating is necessary to raise plasma temperatures to ignition conditions (when fusion reactions will sustain themselves without further heat input). The NUWMAK design employs radio-frequency (RF) supplementary heating in the ion cyclotron range of frequencies in order to startup the plasma. It is proposed to launch a fast magnetosonic wave into a 50-50 DT plasma and heat the ions at the second harmonic cyclotron frequency of deuterium. Most of the present-day magnetic fusion reactor designs advocate the use of neutral beams for heating and fueling purposes. However, the potential advantages of RF heating (such as lower technological demands) led to its choice for NUWMAK. For a power absorption of 80 MW by the plasma in one reactor, a prime power of 136 MW is required from the line or 272 MW total. This number may be optimistic.

3.2 THE REACTOR BLANKET SYSTEM

The NUWMAK blanket system is designed to alleviate or avoid problems which were uncovered in the UWMAK designs. Table 7-1 lists the major problems and solutions.

Table 7-1. Problems, Causes, and Possible Solutions for a Tokamak Blanket

Problems	Caused By	NUWMAK Solution
Thermal Fatigue	Cyclic Plasma	Ti Structure, Boiling Water Cooling
Thermal Storage	Cyclic Plasma	Phase Change (of Breeding Material) Thermal Storage
Intermediate Loop	H_2O-Li Compound Reaction Possibility	Li_{62} Pb_{38} Breeding, Redundant Structure
T-Diffusion	Toward Cooling Water	Multiple Layer Coolant Tube Design
High 1st Wall Thermal Load	High Wall Loading, No Divertor	Ti Structure, Boiling Water Cooling
Coolant Tube Maintenance	Tube Leak	Double Wall Tubes (Redundancy)
Waste Disposal, Reprocessing	Radioactivity	Ti Structure
Blanket Life	Radiation Damage	Low Operating Temperature

A cross-sectional view of the NUWMAK blanket is shown in Figure 7-7. The blanket structure is a titanium alloy, Ti-6Al-4V, designed with a maximum temperature of 400°C at the coolant tube wall for phase stability. The maximum design temperature in the blanket is 500°C. The coolant is boiling water at 300°C with a pressure of 8.6 MPa (1250 psi). The design life for the blanket module is two years.

The blanket resembles a large phase change energy storage tank. The first wall is formed by a continuous bank of tubes, with the space between the tubes filled with Li-62 Pb-38, the breeding and energy storage material. This breeding material is solid around the coolant tube and liquid in between the tubes, with energy storage provided by the movement of the solid-liquid interface (melting temperature is 464°C).

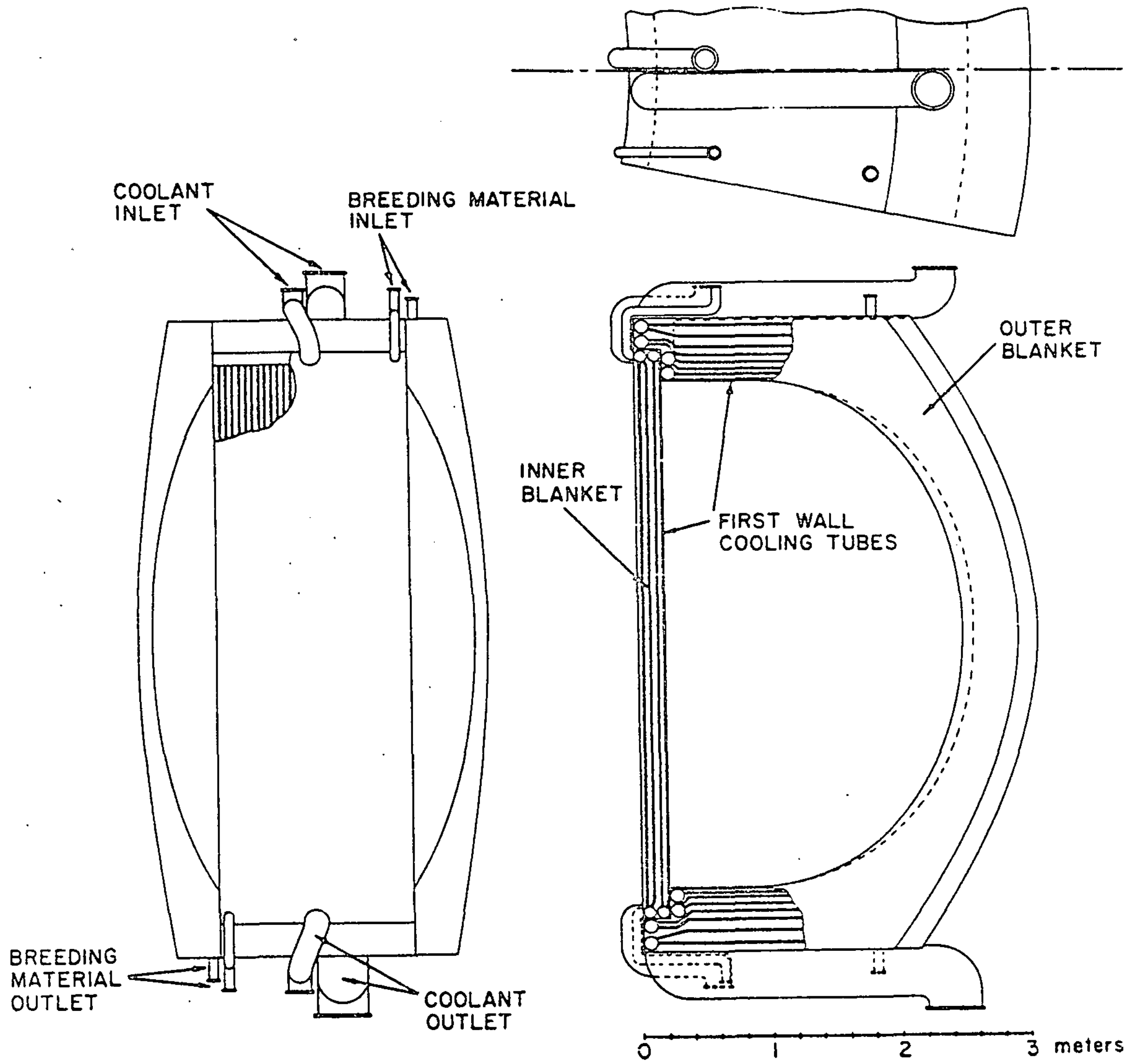


Figure 7-7. Cross-Sectional View of Blanket

3.3 THERMODYNAMIC PARAMETERS

The NUWMAK reactor operates with a cycle length of 245 seconds: 225 seconds of burn followed by 20 seconds of down time. The heat stored in the blanket material provides energy to the coolant during the down time, reducing the cyclic variation from 70% to 30% of the maximum energy to the turbines. As a 30% variation is still unacceptable, a steam drum is used and the feed water temperature is adjusted. Figure 7-8 is a schematic of this load-leveling system. Constant electrical output can be achieved with this system. Simultaneous operation of the two reactors is not necessary for constant electrical output.

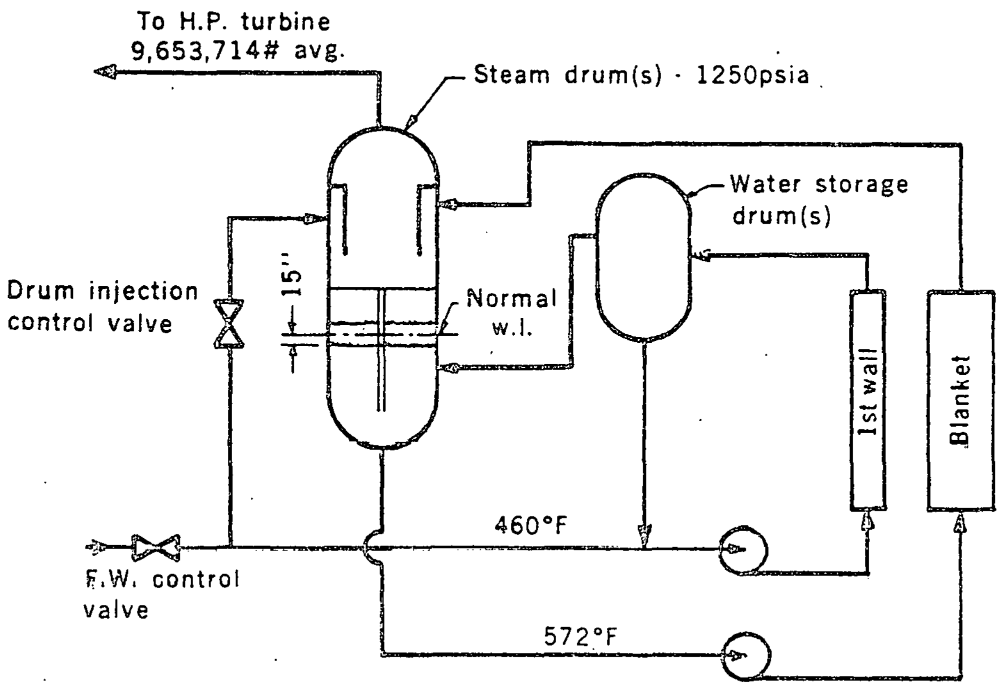


Figure 7-8. Schematic Showing Components in NUWMAK Load-Leveling System

The thermodynamic parameters for one NUWMAK reactor are given in Table 7-2. Two reactors would produce 4566 MW of gross power during burn with a net electrical output of 1320 MWe. Since the burn time is 92% of the cycle time, the net thermal efficiency is 31.5%.

Table 7-2. Summary of Thermodynamic Parameters for One NUWMAK Reactor

Parameter	Value
Power Output (During Burn)	2283 MW
Blanket Energy (Continuous)	1900 MW
Neutron Wall Loading	4.34 MW/m^2
First Wall Area	360 m^2
Total Thermal Wall Loading	6.34 MW/m^2
First Wall Thermal Loading	1.08 MW/m^2
Plasma Burn Time	225 Second
Plasma Down Time	20 Second
Structure	Ti Alloy
Breeding Material	$Li_{62}Pb_{38}$ Eutectic
Energy Storage Material	$Li_{62}Pb_{38}$ Eutectic
Coolant	Boiling H_2O
Coolant Temperature	300°C
Coolant Pressure	8.6 MPa
Maximum Coolant Wall Temperature	400°C
Maximum Coolant Wall Stress	100 MPa
Maximum Blanket Temperature	500°C
Average Coolant Tube Thermal Load	44 W/cm^2
Total Coolant Tube Surface Area	4350 m^2
Net Power Output (Continuous)	660 MWe
Net Thermal Efficiency	31.5%

3.4 FUEL USE

In a "worst case" fueling scheme with deuterium-tritium (DT) gas puffing and "shallow" DT pellet injection, 13.82×10^{20} tritium atoms/sec. are burned in the two reactors to produce 4566 MWt. Tritium is injected as a DT gas blanket at a rate of 4.06×10^{22} T atoms/sec and as DT pellets at a rate of 18.06×10^{22} T atoms/sec. This results in a burn fraction of only 0.62%. Tritium in storage for one day's supply at a burn cycle duty factor of 91.8% is 88 kg. The tritium inventory under this scheme is given in Table 7-3.

Table 7-3. Tritium Inventory Under a DT Pellet Fueling Scheme

Components	Amount of Tritium
Fueling System	
Cryopumps (4 hr. cycle time)	84.0 kg
Storage (1 day's supply, 91.8% duty factor)	88.0 kg
Purification System	
Distillation Columns	1.6 kg
Blanket (no change over original case)	0.18 kg
TOTAL	173.8 kg

The detailed calculations for "deep pellet" fueling have not yet been worked out. However, it has been found that injection of tritium deep into the center of a plasma surrounded by a cold gas blanket of D_2 should increase the particle confinement time at the plasma's center by a factor of ten compared to the "shallow pellet" fueling technique. Thus, the anticipated burn fraction would be about 6%. This represents a best case fueling scheme and would have associated with it inventories and handling capacities reduced by a factor of about ten.

The tritium, after initial fueling, is recovered from the blanket breeding material. A breeding ratio of 1.54 is planned to ensure a continuing supply of tritium. Residual tritium and deuterium are also recovered from the plasma and recycled.

4.0 ENVIRONMENTAL CHARACTERISTICS

There are four direct environmental effects caused by fusion power plants:

- Water/air emissions of radioactive tritium
- Radioactive solid waste (blanket and structural components)
- Use of water resources
- Use of land resource

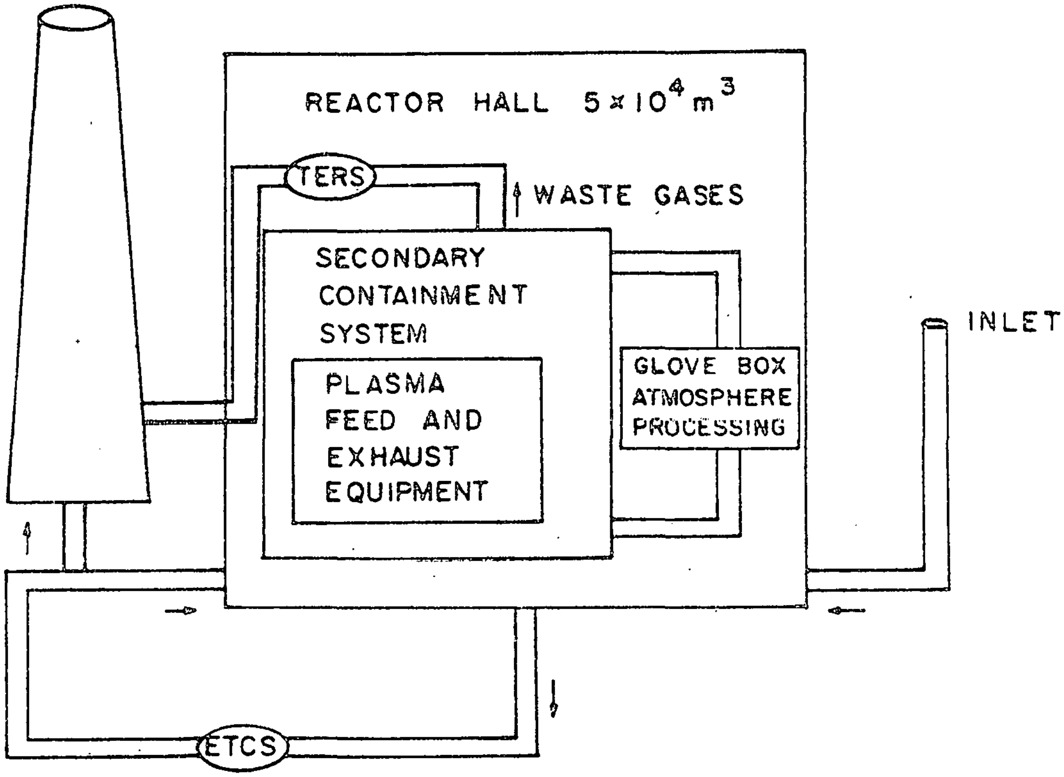
4.1 TRITIUM

The total tritium inventory in NUWMAK may amount to more than 10^{10} Ci. In order to limit tritium releases from NUWMAK to less than 10 Ci per day, tritium losses must be limited to one part in one hundred million on a daily basis. Such a monumental task must rely on the most conservative containment measures possible. Essentially perfect containment of tritium depends on clearly identifying possible routes of tritium release. During normal operation, plasma fueling and fuel purification components, storage (both normal and emergency), breeding and tritium extraction system components, and the first wall and blanket coolant are all sources of potential tritium losses. Tritium containment associated with each of these systems is examined in the analysis of a multi-layer containment system.

The three-level containment system (Figure 7-9) is designed to deal with tritium release under both normal and off-normal conditions. Each level prevents the dilution of released tritium so that it can be recovered before permeating to the next barrier.

The primary containment system consists of those pipes and other structural elements which contain tritium or tritium-bearing materials. These components must demonstrate high structural integrity for the containment of tritium. Connections must be welded and leak tested extensively with helium prior to the introduction of tritium. Division of the fueling and fuel storage system into eight identical units reduces the size of the maximum tritium release possible.

The secondary containment system consists mainly of a second physical barrier around primary system components. Thus, primary system piping outside the plasma chamber is contained within larger diameter piping. A slowly



LEGEND:

TERS = TRITIUM EFFLUENT REMOVAL SYSTEM
ETCS = EMERGENCY TRITIUM CONTAINMENT SYSTEM

Figure 7-9. Tritium Effluent System Design

flowing inert gas is passed through the annulus and monitored for tritium leakage. Large pieces of equipment requiring maintenance or adjustment are enclosed in glove boxes. Estimates currently hold that approximately 1% of the building volume will contain high enough levels of radioactivity to require enclosure within glove boxes. These glove boxes will contain a circulating inert gas which is monitored for tritium.

If the level of tritium goes above 2ppm, the glove box atmosphere can be diverted to a tritium removal system (TERS) or an emergency detritiation system (ETCS) as needed. Especially leaky components of the primary system can be enclosed in special glove boxes equipped with cryogenic absorption or hydrogen getters to control tritium losses when needed.

The tertiary containment system includes the reactor hall, rooms containing tritium processing equipment, the reactor building itself, the tritium effluent removal system (TERS), and the emergency tritium containment system (ETCS). The TERS is designed to operate on routine tritium losses while the ETCS is only used under off-normal conditions.

As with the primary and secondary systems, the reactor building is subdivided to reduce both the extent of loss and the extent of contamination in the event of a leak. Each reactor hall has a volume of 8.7×10^4 m^3 and may be divided radially to provide the least impediment to maintenance operations. The reactor building is maintained at 70 torr during operation, with the capability of attaining 10 torr under emergency conditions.

About 20% of the building volume atmosphere per day should be circulated through the building from areas of smallest to largest radioactive hazard before leaving through a stack of sufficient height to guranatee proper dispersal of the effluent. Under normal operation, this stack effluent would contain about 1 Ci per day. The main reactor hall should not be ventilated routinely due to the existence of the short-lived, but hazardous isotopes ^{13}N, ^{16}N, and ^{41}Ar created by neutron leakage from the reactor.

Routine processing of exhaust gases from vacuum pumps and purge gases is performed by the TERS. The TERS converts gaseous waste (HT, tritiated hydrocarbons, etc.) to tritiated water which is collected. This water and other liquid and solid tritiated waste is then fixed for burial in a solid matrix such as concrete.

The emergency tritium containment system (ETCS) consists of a heated catalyst to oxidize HT and T_2 to HTO and T_2O, alumina beds presaturated with water at 100% humidity, and the required air handling equipment. The ETCS is used in the event of a simultaneous breakdown of both the primary and secondary systems to rapidly detritiate air from contaminated areas of the reactor building. During cleanup, the inlet dampers of contaminated areas are closed and only a small fraction of fresh air is allowed to circulate to reduce tritium losses from the stack.

One further source of tritium leakage is the boiling water coolant. It has been calculated that the leak rate of tritium into the cooling water will be limited to a few curies per day. In the event that the leak rate increases, it is possible, at comparable costs, to remove tritium (in the range of 0.001 to 10 μCi/mℓ), either by combined electrolysis-catalysis or by molecular photo-excitation.

4.2 BLANKET (SOLID RADIOACTIVE) WASTE

The 14 MeV neutrons from the fusion reaction induce radioactivity in the structure surrounding the plasma. Figure 7-10 shows the radioactivity of the reactor in curies per watt thermal. For comparison purposes, the activity of UWMAK-I is also shown. Most of the activity originates in the inner region of the blanket. In comparing the activity of the titanium alloy in NUWMAK with the stainless steel UWMAK-I design, it is seen that some improvement has been made especially in the one year to 1000 year time span. Initially the activity per watt is only lower by a factor of about two. The afterheat results (Figure 7-11) and Biological Hazard Potential (BHP) results (Figure 7-12) show qualitatively similar behavior with the primary difference being the very long term behavior of the BHP for NUWMAK.

The radioactivity, afterheat, and BHP after one year of continuous operation are 0.8 curie/Wt, 0.5% of operating power, and 2×10^2 km^3 air/kWt, respectively. However, they drop by between 4 to 5 orders of magnitude 10 years after shutdown.

The blanket is expected to be replaced every two years with the material processed and stored on the plant site.

4.3 LAND AND WATER USE

The two-unit reference fusion plant is expected to require a 500 acre site including the mainplants, switchyard, cooling towers, access roads and buffer zones. Temporary on-site storage of structural radioactive waste requires a negligible area. The radioactive material storage requirement in volumetric terms is about 8.5 m^3/yr for each of the two units.

The primary water use is for cooling and cooling tower blowdown and is expected to be comparable to that of an equivalent capacity BWR.

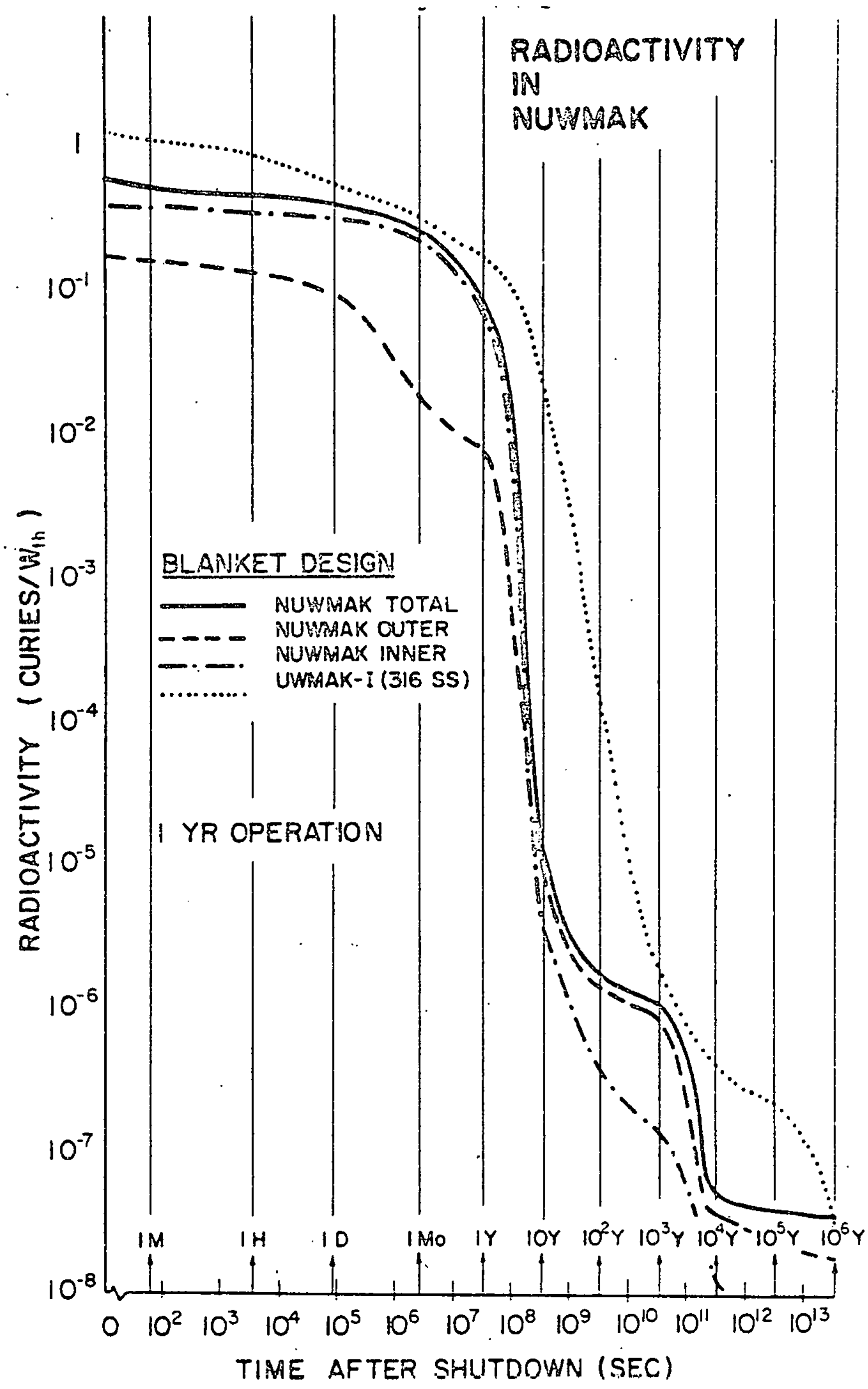


Figure 7-10. Radioactivity of the NUWMAK

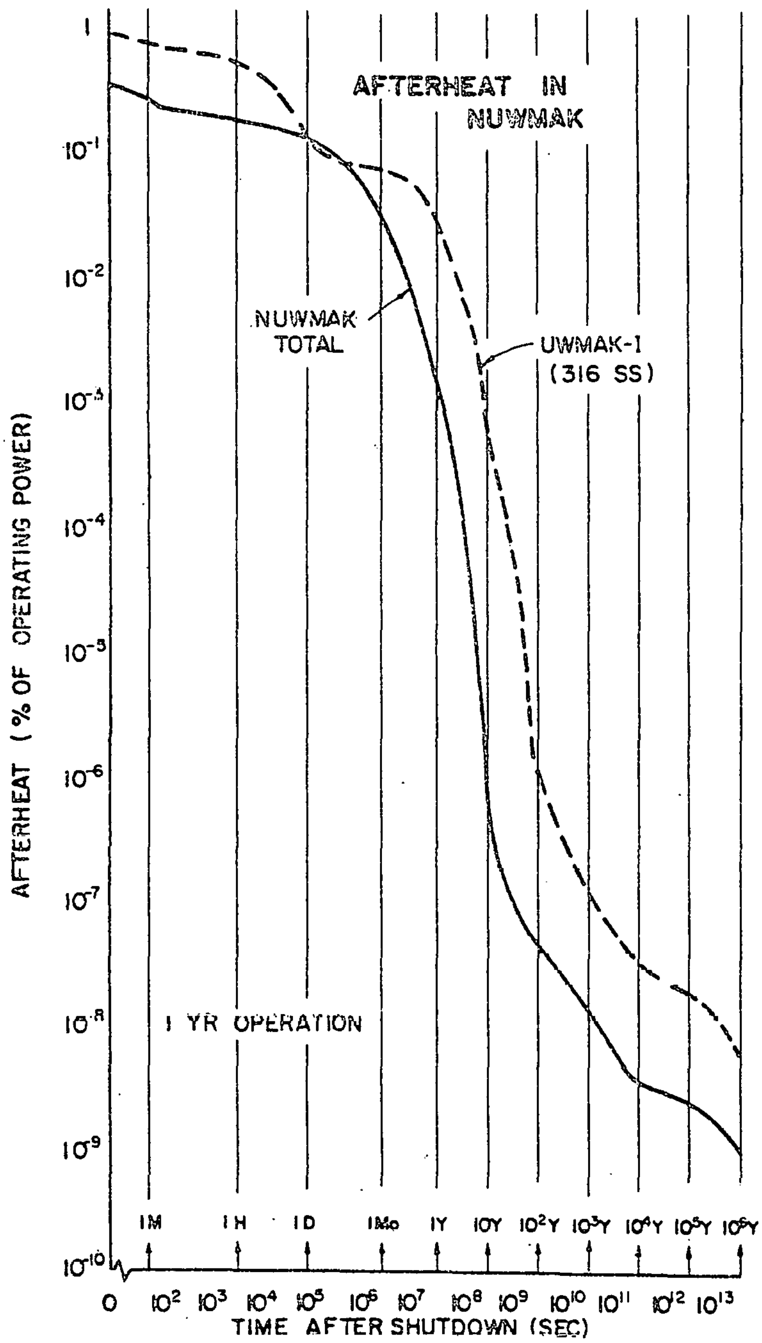


Figure 7-11. Afterheat in NUWMAK

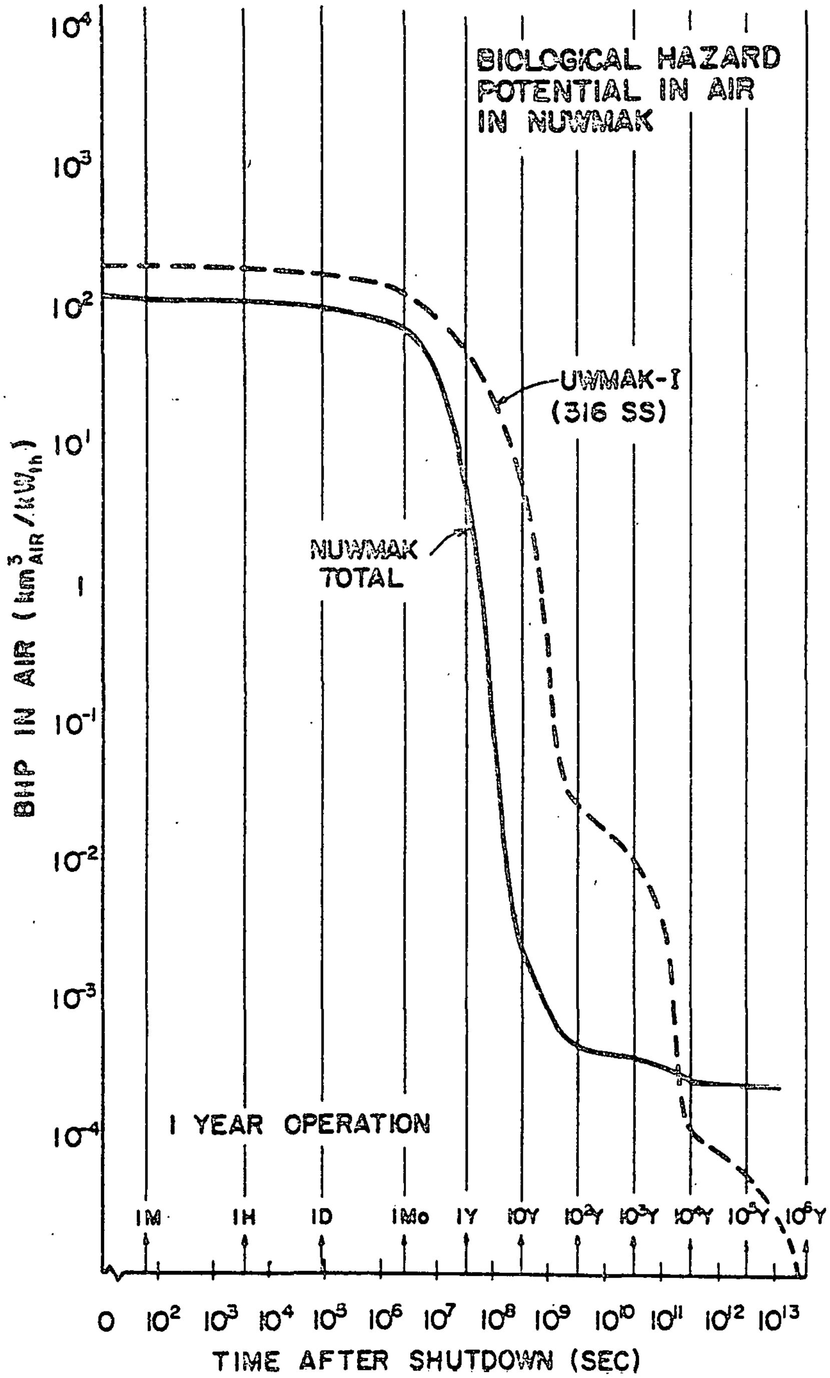


Figure 7-12. Biological Hazard Potential for NUWMAK

5.0 CONSTRUCTION AND OPERATING CHARACTERISTICS

5.1 CONSTRUCTION TIME

The NUWMAK study assumed an eight-year construction period for a single 660 MWe plant. This estimate is two years less than that for earlier UWMAK designs on the grounds that NUWMAK is a smaller and less complicated reactor which utilizes current BWR technology in the power cycle. For the two-unit reference plant characterized herein, a ten year total construction time is assumed with the first unit being completed after eight years and the second unit two years later.

5.2 CONSTRUCTION PERSONNEL REQUIREMENTS

A total direct craft labor requirement of 2.13×10^7 man-hours is estimated for construction of the reference two-unit plant. About 10 percent of this labor requirement is for construction of the reactor plants themselves, which is about the same as that required for construction of the reactor portion of a 1190 MWe BWR. A construction personnel requirements breakdown by craft type is not available.

5.3 RESOURCE REQUIREMENTS

The total materials requirements for a 300 GWe installed capacity of NUWMAK-type reactors are shown in Table 7-4. While this level of fusion development would not place a severe burden on resources available from the domestic market at projected or possible future prices, three materials, Nb, W, and Co, would be required from foreign sources. The supply and demand for these materials would require careful monitoring as fusion power develops.

Table 7-4. Materials Requirements and Availability in a 300 GWe Economy of NUWMAK Type Reactors

Group & Metal	Total Requirement (in metric tonnes x 10^3)
Group A - Materials available from domestic mines at market prices	
Boron	670
Carbon	328
Copper	355
Iron	16,909
Lead	849
Lithium	19
Magnesium	2
Zirconium	0.5
Molybdenum	20
Group B - Materials available from domestic mines at 3X market prices	
Aluminum	672
Chromium	104
Titanium	386
Manganese	16
Vanadium	35
Nickel	13
Group C - Materials available in adequate amounts only from foreign sources	
Niobium	23
Tungsten	312
Cobalt	20

5.4 OPERATING PERSONNEL REQUIREMENTS

Total staffing requirements for the reference fusion plant are estimated to be 300 persons including security and peak maintenance personnel. This estimate is based on staffing requirements for LWR plants having two 400-700 MWe units per site. A breakdown of the operating staff is shown below.

Estimated Staff Requirements for Reference Fusion Plant*

Plant manager's office	
Manager	1
Assistant	2
Quality assurance	4
Environmental control	1
Public relations	1
Training	1
Safety	1
Administrative services	15
Health services	1
Security	56
Subtotal	83
Operations	
Supervision (excluding shift)	2
Shifts	48
Subtotal	50
Maintenance	
Supervision	8
Crafts	22
Peak maintenance annualized	110
Subtotal	140
Technical and engineering	
Reactor	2
Radiochemical	2
Instrumentation and controls	2
Performance, reports, and technicians	21
Subtotal	27
TOTAL STAFF	300
Less security	244
Less security and peak maintenance	134

*Source: "A Procedure for Estimating Nonfuel Operation and Maintenance Costs for Large Steam-Electric Power Plants," ORNL/TM-6467, January 1979.

5.5 PLANT AVAILABILITY

Unit availability in the NUWMAK study is estimated to be 80.8 percent. This estimate is based on four weeks (672 hours) of unscheduled downtime per year and six weeks (1008 hours) of scheduled downtime per year. It was assumed that all the first wall/blanket material and the limiters will be replaced every two years, with one-half of the first wall/blanket/limiter material replaced each year on a regular schedule. The six week scheduled downtime period must thus be adequate for replacement of eight of the sixteen first wall/blanket modules.

For the reference plant characterization it was assumed the two-unit plant would operate at an overall capacity factor of 70 percent.

6.0 COST CHARACTERIZATION (FUSION)

The base capital costs estimated for the 1320 MWe reference fusion plant have been derived from cost data presented in the "NUWMAK" report and from the "Energy Economic Data Base (EEDB) Program Phase I" report. The NUWMAK report was used as the primary source of data while the EEDB was used to derive the direct labor components for each of the major accounts (except for those of the reactor plant for which the NUWMAK presents data). Direct and indirect costs are presented on a consistent January 1, 1978 basis.

6.1 DIRECT CAPITAL COSTS

The NUWMAK design report develops a grass roots estimate for the plant's reactor plant equipment and derives the balance of plant costs from the EEDB boiling water reactor design costs. A direct craft labor requirement of 2.13×10^6 man-hours is estimated for construction of the reactor plant,* while all other accounts are specified by total dollar cost with no specific breakout of the labor component. Thus, for consistency with each of the other technologies characterized in this report, the labor component for each direct cost account was estimated, based on the ratio of direct labor cost to total cost for the balance of plant accounts of the EEDB boiling water reactor design. As this design served as the basis for estimating the original NUWMAK costs, consistency is preserved.

The NUWMAK design report assumed an average labor cost of $12.50/man-hour. This cost has been adjusted slightly to $13.04/man-hour for consistency with the average labor costs used in the reference LWR and LMFBR characterizations.

For each of the accounts, the NUWMAK study defines four components of cost: identified equipment costs, design allowances, contingency, and spare parts. Contingency and spare parts costs have not been included in the base direct costs for consistency with the cost estimates of the other technologies. Design allowances, as defined in the NUWMAK report, are costs estimated to account for items overlooked in the engineering design. These costs are estimated in the NUWMAK report at 10% of each equipment account total, except

*This labor requirement is about the same as that required for the construction of the reactor portion of a 1190 MWe boiling water reactor.

for the reactor plant equipment where 20% is used. In light of the status of development and conceptual nature of the fusion system, it was judged appropriate to include these costs in the base cost estimate.

Thus, direct capital cost includes the costs of all materials, components, structures, and associated direct craft labor necessary to construct the reference facility at the plant site. Delivered costs for components, structures, and materials are used. Base indirect costs include site temporary construction facilities, payroll insurance and taxes, and other construction services, such as home and field office expenses, field job supervision and engineering services. Specifically excluded from the base construction cost estimate are the items specified above, and items that are sensitive to the particular policies and preferences of the individual utility and to the specific plant site and prevailing economic factors being considered. These exclusions include the following list of items:

1. Owner's Costs - Consultants, Site Selection, etc.
2. Federal, State and Local Fees, Permits and Taxes
3. Interest on Capital Construction Funds
4. Price Escalation during Construction
5. Contingency Funds
6. Owner's Discretionary Items - switchyard and transmission costs, waste disposal costs, spare parts, and initial fuel supplies

With only a few exceptions, cost estimates provided in the NUWMAK report were taken directly as those for the reference design. The exceptions include a modification of average labor costs as previously discussed and the inclusion of a second 660 MWe unit on the same plant site. With regard to the second unit, only land costs (Account 20) and structures and improvements costs (Account 21) were assumed to be shared by the two units. Land costs are based on a 500 acre site valued at $4,480/acre with half the total price assigned equally to each unit. Unit 2, Structures and Improvements costs, were estimated at 90% of the Unit 1 labor costs with savings attributable to reduced labor requirements for structures and improvements, and to learning as a result of construction of unit 1. Table 7-5 summarizes the direct equipment, materials, and labor costs estimated for the 1320 MWe, two-unit reference fusion plant.

Table 7-5. Estimated Direct Capital Costs for 1320 MWe* Fusion Reference System (January 1, 1978 Dollars)

Account	Description	Dollars in Thousands		
		Unit 1	Unit 2	Total
20	Land and Land Rights	1,120	1,120	2,240
21	Structures and Improvements	52,279	47,051	99,330
22	Reactor Plant and Special Materials	457,277	457,277	914,554
23	Turbine Plant Equipment	74,433	74,433	148,866
24	Electric Plant Equipment	24,676	24,676	49,352
25	Misc. Plant Equipment	8,234	8,234	16,468
26	Main Condensate Heat Rejection System	12,633	12,633	25,266
	Total Equipment & Materials Costs	630,652	625,424	1,256,076
	Site Labor @ $13.04/man-hour	142,136	135,029	277,165
	TOTAL DIRECT CAPITAL COSTS	772,788	760,453	1,533,241

*Two-unit plant, each unit at 660 MWe

6.2 INDIRECT COSTS

Indirect costs for construction, home office, and field office engineering and services are estimated, based on the ratio of these cost accounts to the total direct costs for the EEDB boiling water reactor plant. In general, this results in a higher indirect cost estimate for the fusion plant than is estimated in the NUWMAK report. For a boiling water reactor, construction services (Account 91) are 16% of total direct costs, home office engineering and services (Account 92) are 19% of total direct costs, and field office engineering and services (Account 93) an additional 6%. (The NUWMAK study assumes 15%, 15% and 5% respectively.) Table 7-6 summarizes the estimated indirect costs which total $628,628,000 or 41% of the plant's direct costs.

Table 7-6. Estimated Indirect Capital Costs for 1320 MWe Fusion Reactor Reference System (January 1, 1978 Dollars)

Account	Description	Dollars in Thousands		
		Unit 1	Unit 2	Total
91	Construction Services	123,646	121,672	245,318
92	Home Office Engineering & Services	146,830	144,486	291,316
93	Field Office Engineering and Services	46,367	45,627	91,994
	TOTAL INDIRECT COSTS	316,843	311,785	628,628

6.3 OPERATIONS AND MAINTENANCE COSTS

The NUWMAK study estimates annual operation and maintenance costs, exclusive of scheduled and unplanned replacements and fuel costs, to be 2% of the plant's total direct and indirect capital costs. Annual scheduled replacement of the first wall/blanket material was estimated at $4 million/year for each unit. Additionally, the O&M cost estimate includes an estimate of unscheduled interim replacements taken to be accrued in a sinking fund at 4% real interest per year. Total accrual after 30 years is assumed to be 30% of the plant's total direct and indirect costs exclusive of the reactor plant costs for which scheduled replacements are accounted in the above cost. Table 7-7 summarizes the nonfuel O&M costs assuming a plant capacity factor of 70%.

Fuel costs include the cost for replenishment of burned lithium and for the purchase of deuterium which is estimated to cost $1200/kg. The NUWMAK study estimates these costs to be $449,000/year per reactor at 81% capacity factor. This adjusts to $776,000/year for two units operating at 70% capacity factor.

Table 7-7. Annual Operation and Maintenance Costs--1320 MWe Reference Fusion Reactor System @ 70% Capacity Factor

O&M Account	Cost Estimating Relationship	$1000/yr
General O&M	2% of total direct and indirect costs (.02)(1,533,421 + 628,628)	43,241
First Wall/Blanket Replacement	$4 million/year/unit x 2 units	8,000
Unscheduled Interim Replacements	Sinking Fund accrual of 30% of direct and indirect plant capital costs (excluding direct reactor plant costs) at 30 years and 4% interest	6,662
	Total Nonfuel O&M	57,903

At 70% Capacity Factor:

$$\text{Non-Fuel O\&M:}\quad \frac{(57{,}903{,}000\ \$/\text{yr})(1000\ \text{mills}/\$)}{(1{,}320{,}000\ \text{kW})(8760\ \text{hr/yr})(.7)} = 7.15\ \text{mills/kWh}$$

$$\text{Fuel Costs:}\quad \frac{(776{,}000\ \$/\text{yr})(1000\ \text{mills}/\$)}{(1{,}320{,}000\ \text{kW})(8760\ \text{hr/yr})(.7)} = .10\ \text{mills/kWh}$$

TOTAL 7.25 mills/kWh

APPENDIX
ON CG/CC COST ESTIMATE

Appendix

COST ESTIMATING RELATIONSHIPS FOR REFERENCE COAL GASIFICATION COMBINED CYCLE SYSTEM

This appendix details the cost estimating relationships for direct equipment costs and material costs for the reference 1250 MWe coal gasification facility. The series of tables (listed below) show the intermediate and final results of the procedure used to estimate the reference system costs (two 625 MWe units using Eastern Bituminous Coal) from costs presented in the Energy Conversion Alternatives Study (ECAS) for a single-unit 579 MWe facility using Illinois No. 6 coal. The facility complies to more restrictive environmental emission standards than is applicable to the reference design. All costs in this appendix are in 1975 dollars. The final cost estimate used in the body of the report is presented in January 1, 1978, dollars which have been converted from 1975 dollars by application of the corresponding GNP price deflator index ratio of 1.1365.

The cost estimating procedure was as follows:

1. A detailed equipment and materials cost list for the original ECAS 579 MWe plant using Illinois No. 6 coal (10,788 Btu/lb., 3.9 percent sulfur, 9.6 percent ash, and 59.6 percent carbon) was compiled under a code of accounts similar to that used in the Energy Economic Data Base. For the most part, except for the heat rejection system, this code of accounts is used in the ECAS study. (Another code of accounts used in the ECAS study for preparation of their equipment list is shown under the equipment descriptions in the following tables to provide traceability to the original ECAS document.) Column A in the following tables shows these original costs separately for the plant's gasification module (GM) and balance of plant (BOP). The total cost is also shown.

2. Cost estimating exponents (α) were assigned to each of the major pieces of equipment based on an analysis of equipment lists and cost estimating exponents for conventional coal burning powerplants. Where no direct parallel of equipment type existed, basic design similarities were taken into consideration (e.g., tank, vessel, pump, turbine), before selecting an appropriate exponent. These exponents, shown in Column B of each table, were subsequently used in the following equation to make adjustments in cost based on equipment sizing, capacity, or loading:

$$\text{Cost of Component B} = \text{Cost of Component A} \times \left(\frac{\text{Capacity of B}}{\text{Capacity of A}}\right)^{\alpha}$$

where α is the cost estimating exponent.

3. Plant equipment loading or capacity ratios were then determined for: (a) a 579 MWe facility using the Eastern Bituminous coal rather than the Illinois No. 6 coal (11,026 Btu/lb., 3.2 percent sulfur, 10.29 percent ash, 61.49 percent carbon), and (b) conforming to less stringent environmental standards applicable to the reference system. Applicable ratios for the modified 579 MWe plant are shown in Column C of the following tables. Column D shows the costs for each piece of equipment, separately for the plant's gasification module and balance of plant. The costs are derived by application of loading ratios (C), cost estimating exponents (B) to the original ECAS cost estimates (A).

4. After correcting for coal characteristics and environmental standards, the system was sized to a net output of 625 MWe. In order to meet the ash throughput design limitation for each vessel and to ensure reliable operation, two additional gasification vessels were required. These additional vessels were not costed using the exponent technique. Rather, they were added at their given unit costs since no modification was assumed for the vessel itself. A 7.9 percent increase in component capabilities and loadings resulted in scaling up from 579 to 625 MWe. Costs for a single unit 625 MWe facility using the reference Eastern Bituminous coal are given in Column E in the following tables. These values are derived from the Column D values and the above cost estimating equation, a capacity ratio of 1.079 and cost estimating exponents shown in Column B.

5. Estimates were then made on a component-by-component basis of the incremental cost of adding a second 625 MWe unit on the same site. In some cases (e.g., coal handling equipment), that portion of the equipment cost assignable directly to the individual unit's gasification module was <u>not</u> considered as shared equipment, while that equipment assignable to the balance of the plant was assumed to be twice the single unit capacity and shared by both units. The relationship indicated for estimating the incremental second unit cost for independent and shared facilities when identical capacities or loadings are required for each unit is as follows:

   Independent (not shared) Equipment: $U_2 = U_1$

   Shared Equipment: $U_2 = U_1\ (2^{\alpha} - 1)$

   where U_1 = Unit 1 cost

   U_2 = Unit 2 incremental cost

   α = cost estimating exponent

   Column F indicates the shared or not shared assumption for each of the pieces of equipment, and Column G shows the second unit incremental cost.

6. All costs have been derived in 1975 dollars. The final table summarizes the direct capital costs for Unit 1 and Unit 2 of the reference facility for each major account. These values were derived by adding the component costs under each account for Unit 1 (Column E) and Unit 2 (Column G) and then escalating each of the account costs to January 1, 1978 dollars by multiplying by 1.1365 determined from the ratio of GNP price deflators. Consistent with the other technologies, land costs were estimated from a 500 acre site valued at \$4,480 per acre. Total site land cost was assigned equally to each unit.

Table A-1. Equipment and Materials List-Structures and Improvements - Account 21 (ECAS Acct 1.0) 1975 Dollars

COLUMN	A			B	C	D		E		F	G	
ECAS EQUIPMENT NUMBER AND DESCRIPTION	579 MWe ECAS COST (1000$) GASIFICATION MODULE	BOP	TOTAL	COST ESTIMATING EXPONENT (α)	CAPACITY OR LOADING RATIO	MODIFIED 579 MWe UNIT COSTS (1000$) GAS. MOD.	BOP	REFERENCE FIRST UNIT COST - 625 MWe (1000$) GAS MOD.	BOP	SHARED(S) OR NOT SHARED(N) BY 2nd UNIT (Note 1)	REFERENCE SECOND UNIT INCREMENTAL COST - 625 MWe (1000$) GAS. MOD. (Note 1)	BOP
3.0 Process Mechanical Equipment												
3.7 Turbine Hall Cranes		380	380	.20	1.00		380		386	S		347
5.0 C & Structural												
5.1 Substructures	104	2,200	2,304	.20	1.00	104	2,200	106	2,234	S	95	2,011
5.2 Superstructures	979	4,690	5,669	.20	1.00	979	4,690	994	4,762	S	895	4,286
5.3 Earthwork		300	300	.20	1.00		300		305	S		275
5.4 Cooling Tower Basins, Circ. Water		910	910	.20	1.00		910		924	S		832
7.0 Yardwork and Misc.												
7.1 Site Preparation		10	10	.20	1.00		10		10	S		9
7.2 Site Utilities		50	50	.20	1.00		50		51	S		46
7.3 Roads and Railroads		1,040	1,040	.20	1.00		1,040		1,056	S		950
7.4 Yard Fire Protection		600	600	.20	1.00		600		609	S		548
7.5 Water Treatment Ponds		20	20	.20	1.00		20		20	S		18
7.6 Lab, Office, Shop		280	280	.20	1.00		280		284	S		256
TOTALS			11,560				11,741					10,568

NOTE 1. A cost estimating exponent (α) of 0.92 used for all shared structures and improvements cost of Unit 2 component = $(2^{0.92}-1)$ x cost of unit 1 component.

Table A-2. Equipment and Materials List - Coal Handling Gasification and Gas Cleanup - Account 22 (ECAS Acct. 2.0) - 1975 Dollars

COLUMN	A			B	C	D		E		F	G	
	579 MWe ECAS COST (1000$)			COST ESTIMATING EXPONENT (α)	CAPACITY OR LOADING RATIO (Note 1)	MODIFIED 579 MWe UNIT COSTS (1000$)		REFERENCE FIRST UNIT COST - 625 MWe (1000$)		SHARED(S) OR NOT SHARED(N) BY 2nd UNIT (Note 2)	REFERENCE SECOND UNIT - INCREMENTAL COST - 625 MWe (1000$)	
ECAS Equipment Number and Description	Gasification Module	BOP	TOTAL			GAS.MOD	BOP	GAS.MOD	BOP		GAS.MOD.	BOP
3.0 Process Mechanical Equipment												
3.5 HX, Tanks, Vessels		1,260	1,260	.85	1.00		1,260		1,344	N	128	1,344
3.7 Cranes	120		120	.85	1.00	120		128		N		1,365
3.8 Booster Air Compressor		1,280	1,280	.85	1.00		1,280	1,722	1,365	N		1,365
3.9 Coal Handling	1,656	4,720	6,376	.85	.97	1,614	4,599	1,722	4,906	N/S	1,722	3,937
3.10 Ash Handling	68	1,380	1,448	.85	1.05	71	1,438	76	1,534	N/S		347
3.11 Sulfur Handling		490	490	.85	.80		405		432	S		347
3.12 Cooling Towers		555	555	.50	1.00		555		577	N		577
6.0 Process Piping & Instrumentation												
6.2 Fuel Gas Large Piping		160	160	.85	1.00		160		171	N		171
6.3 Other Large Piping	568	1,960	1,960	.85	1.00	568	1,960	606	2,091	N	606	2,091
6.4 Small Piping	48		48	.85	1.00	48		51		N	51	
6.5 Hangers & Misc.	99	250	349	.85	1.00	99	250	106	267	N	106	267
6.6 Piping Insulation	25		25	.85	1.00	25		27		N	27	

Table A-2. Equipment and Materials List - Coal Handling Gasification and Gas Cleanup - Account 22 (ECAS Acct. 2.0) - 1975 Dollars (Continued)

COLUMN	A			B	C	D		E		F	G	
	579 MWe ECAS COST (1000$)			COST ESTIMATING EXPONENT (α)	CAPACITY OR LOADING RATIO (Note 1)	MODIFIED 579 MWe UNIT COSTS (1000$)		REFERENCE FIRST UNIT COST - 625 MWe (1000$)		SHARED(S) OR NOT SHARED(N) BY 2nd UNIT (Note 2)	REFERENCE SECOND UNIT INCREMENTAL COST - 625 MWe (1000$)	
ECAS EQUIPMENT NUMBER AND DESCRIPTION	GASIFICATION MODULE	BOP	TOTAL			GAS.MOD.	BOP	GAS.MOD.	BOP		GAS.MOD.	BOP
8.0 Gas Cleanup System												
8.1 Pumps & Drives		600	600	.85	.80		496		529	S		425
8.2 Heaters and Exchangers		17,920	17,920	.85	.80		14,324		15,814	S		12,691
8.3 Tanks and Vessels		2,210	2,210	.40	.80		2,021		2,083	S		666
8.4 Ammonia Plant Compressor		420	420	.85	.80		347		370	S		297
8.5 Claus Plant		8,400	8,400	.60	.80		7,347		7,690	S		3,966
8.6 Wellman-Lord Plant		8,555	8,555	.60	.80		7,483		7,832	S		4,039
9.0 Gasification Module												
9.1 Gasifiers	25,029		25,029	1.00	16/14	25,029	28,605			N	28,605	
9.2 Wash Coolers	357		357	1.00	16/14	357			408	N	408	
9.3 Coal Hoppers	150		150	1.00	16/14	150			171	N	171	
TOTALS			78,275						79,005		65,414	

Note 1: Ratio of 16/14 for gasifiers, coolers and hoppers applied in columns E and G only

Note 2: N/S indicates gasifier module not shared, balance of plant shared.

Table A-3. Equipment and Materials List-Prime (Gas Turbine) Cycle Equipment - Account 23 (ECAS Acct. 3.0) - 1975 Dollars

COLUMN	A			B	C	D		E		F	G	
ECAS EQUIPMENT NUMBER AND DESCRIPTION	579 MWe ECAS COST (1000$) GASIFICATION MODULE	BOP	TOTAL	COST ESTIMATING EXPONENT	CAPACITY OR LOADING RATIO	MODIFIED 579 MWe UNIT COSTS (1000$) GAS. MOD.	BOP	REFERENCE FIRST UNIT COST - 625 MWe (1000$) GAS. MOD.	BOP	SHARED(S) OR NOT SHARED(N) BY 2nd UNIT	REFERENCE SECOND UNIT INCREMENTAL COST - 625 MWe (1000$) GAS. MOD.	BOP
2.0 Turbine Generators												
2.2 Gas Turbine Generators (Install)		170	170	.70	1.00		170		170	N		170
Major Equipment Procurement Gas Turbine Generators (4)		32,400	32,400	.70	1.00		32,400		32,400	N		32,400
TOTALS			32,570				32,570		32,570			32,570