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Schematics and Case Studies

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Summary

In the framework of the SP1 of the ARCHER project, the purpose of this document is to present the thermal heat balance of a cogeneration plant composed of: A nuclear facility, composed by one or several High Temperature Reactors (HTR) that will generate electricity and heat. An industrial facility that has a high demand of high pressure steam, and that could hence take advantage of the heat generated by the nuclear facility to produce steam. In order to achieve this task, the work of several participants has been required: Westinghouse provided a description and input data for the nuclear source (Pebble Bed High Temperature Reactor). ALSTOM proposed a description and a heat balance of the secondary circuit of a generic HTR cogeneration plant. SAIPEM gathered data from an industrial end user (an oil refining and petrochemical complex) and presented it in the PROCHEM Case Study Data Using the input data mentioned above, Empresarios Agrupados proposed a model and a thermal heat balance of cogeneration plant that would combine a Westinghouse HTR reactor, use a secondary circuit similar to what ALSTOM proposed, and deliver steam and electricity to the industrial end user described by SAIPEM. This report thus provides an example, using real end user data (an oil refining and petrochemical complex) of how a HTR could be used in a cogeneration plant, which was one of the objectives of WP 1.1 of the ARCHER project.

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ACRONYMS

ARCHER: Advanced Reactor for Cogeneration of Heat and Electricity R&D

HP: High Pressure

HRSG: Heat Recovery Steam Generator

HTR: High Temperature Reactor

ID: Input Data

LP: Low Pressure

MP: Medium Pressure

SG: Steam Generator

EXECUTIVE SUMMARY

In the framework of the SP1 of the ARCHER project, the purpose of this document is to present the thermal heat balance of a cogeneration plant composed of:

- A nuclear facility, composed by one or several High Temperature Reactors (HTR) that will generate electricity and heat.
- An industrial facility that has a high demand of high pressure steam, and that could hence take advantage of the heat generated by the nuclear facility to produce steam.

In order to achieve this task, the work of several participants has been required:

- Westinghouse provided a description and input data for the nuclear source (Pebble Bed High Temperature Reactor)
- ALSTOM proposed a description and a heat balance of the secondary circuit of a generic HTR cogeneration plant.
- SAIPEM gathered data from an industrial end user (an oil refining and petrochemical complex) and presented it in the “PROCHEM Case Study Data”
- Using the input data mentioned above, Empresarios Agrupados proposed a model and a thermal heat balance of cogeneration plant that would combine a Westinghouse HTR reactor, use a secondary circuit similar to what ALSTOM proposed, and deliver steam and electricity to the industrial end user described by SAIPEM.

This report thus provides an example, using real end user data (an oil refining and petrochemical complex) of how a HTR could be used in a cogeneration plant, which was one of the objectives of WP 1.1 of the ARCHER project.

However, it should be highlighted that the benefits for an industrial complex of using an HTR cogeneration plant is still unclear. In the case used in the present report for example (PROCHEM petrochemical complex), the entire cogeneration plant produces:

- 204 MW of steam, which is less than one of the seven boilers used to produce steam for the refinery complex (approximately 100 MW less).

- 157 MW of electricity, which is less than the amount of electrical power used in the refinery complex during winter (approximately 50 MW less).

To sum up, a nuclear power facility would have to be build close to an important industrial complex (thus probably adding difficulty to the licensing process), with the final objective of replacing one of the seven boilers used at the petrochemical complex. It goes without saying that the economic viability of the HTR cogeneration project will be one of the main challenges for that technology in the future.

1. PURPOSE AND SCOPE

The aim of the SP1 of the ARCHER project is to study possible ways of designing a nuclear cogeneration plant, made of:

- A nuclear facility, composed by one or several High Temperature Reactors (HTR) that will generate electricity and heat.
- An industrial facility that has a high demand of high pressure steam, and that could hence take advantage of the heat generated by the nuclear facility to produce steam.

The purpose of this document is to present the thermal heat balance of what could be a demonstration HTR cogeneration plant. This report groups together and presents the work achieved by several participants to model this cogeneration plant:

- Westinghouse provided a description of a Pebble Bed High Temperature Reactor (the complete Westinghouse contribution is presented in Appendix A).
- ALSTOM proposed a model for the secondary circuit of a HTR cogeneration plant (the complete ALSTOM contribution is included in Appendix B).
- SAIPEM gathered data from an industrial user (an oil refining and petrochemical complex) and presented it in the “PROCHEM Case Study Data”, included in Appendix C.

Using the secondary circuit model proposed by ALSTOM (for a more “generic” HTR cogeneration plant) as a starting point, EA developed a thermal heat balance of a HTR cogeneration plant adapted to the specific input data provided by Westinghouse and PROCHEM.

Section 2.1 presents the input data that has been used by EA in the plant thermal heat balance. A few assumptions had to be made, and they are presented in Section 2.2.

Section 3 explains the heat thermal balance model and the choices that have been made. Results are presented in Section 4.

2. INPUT DATA AND HYPOTHESES

2.1 INPUT DATA

LIST OF DOCUMENT INPUT DATA[1]

No.	Source Document			Requirement/Data	Status[2]
	No.	Issue	Title		
1	EE-11-3052 3000 BF GBRA 154219	1	Contribution of Westinghouse – Description of nuclear heat source	NSSS thermal output (Section 2.4.1): 2 x 260 MW	V
2				Main steam conditions at SG outlet (Figure 7.1.1-1): 190 bar / 530 ºC / 203 kg/s	V
3				Feedwater conditions at SG inlet (Figure 7.1.1-1): 240 bar / 180 ºC / 203 kg/s	V
4	-	1	Contribution of SAIPEM SA - PROCHEM Case Study Data	Steam characteristics for the Oil Refining and Petrochemical Complex (Table 6-1) - HP: 31 bar / 260 ºC - MP: 16 bar / 220 ºC - LP: 5,8 bar / 170 ºC	V

[1] ALSTOM's contribution does not appear in the present section as an input data, because it does not contain any compulsory data (e.g. value of flow, pressure, enthalpy…). However, the structure of the thermal cycle proposed by ALSTOM has been the starting point for EA's work (as explained in Section 3) and ALSTOM's contribution thus appear as a reference in the present document (Ref.1).
[2] V stands for "Verified".

2.2 HYPOTHESES MADE BY EA

H.1 The PROCHEM Case Study Data does not provide the proportions of high, medium and low pressure steam required by the petrochemical plant, so assumptions had to be used for these values. These proportions depend largely on the specific processes used in a particular refinery and there is no “typical” number. However, since the high pressure steam could be used both in the process as well as to drive turbopumps, it has been assumed that HP steam is the more useful pressure level for a refinery.

The following hypothesis is made: **50% of the steam provided by the cogeneration plant to the end user will be in HP conditions** (31 bar and 260ºC according to ID.4).

H.2 It has been assumed that the cogeneration plant will **only provide HP and MP steam to the end user**, so as to use only two reboilers instead of three. The end user will easily obtain LP steam from the MP steam by expanding it in a back pressure turbine for example.

H.3 The **total steam flow** to be provided by the cogeneration plant to the end user is supposed to be **80 kg/s**. This value has been chosen for the following reasons:

- It is close to the model of the secondary circuit proposed by ALSTOM: ALSTOM proposed 100 kg/s of steam for a HTR thermal power of 600 MW, while in the present case the HTR thermal power is equal to 520 MW.
- It corresponds to a thermal power provided to the end user of 212 MW, which is the same order of magnitude than one fuel boiler used at the Prochem complex (boiler thermal power range between 123 MW and 350 MW, according to Figure 6-1 and 7-1 of Appendix C).

As a result of the hypotheses H.1, H.2 and H.3, it is assumed that the cogeneration plant will provide to the end user:

- 40 kg/s of HP steam (80 kg/s x 50%).
- 40 kg/s of MP steam.

H.4 The temperature of the cold water supplied by the end user for the process steam generation (tertiary circuit) is assumed to be 50ºC (same assumption as ALSTOM made in its study).

H.5 Main steam pipe pressure drop from SG to ST assumed as 3.3%

The hypotheses regarding the main parameters of the components used in the thermal balance are presented in Table 3-3.

3. DESCRIPTION OF THE COGENERATION PLANT MODEL

3.1 PRIMARY CIRCUIT: THE HIGH TEMPERATURE REACTOR

A complete description of the Westinghouse Pebble Bed reactor is included in Appendix A of the present document. As far as the primary circuit is concerned, the only data that has been used in the thermal heat balance is the thermal power: 520 MW (ID.1).

3.2 TERTIARY CIRCUIT: THE INDUSTRIAL END USER

The industrial end user is considered to be a refinery and petrochemical complex, for which the input data provided by PROCHEM has been used. The complete report provided by SAIPEM is presented in Appendix C of the present document.

The data that have been used in the thermal heat balance for the tertiary circuit are summed-up in Table 3-1.

Table 3-1: Tertiary circuit (end user) data used as inputs in the thermal balance

Parameter	Value	Unit	Reference
End user water input temperature	50	ºC	H.4
HP steam pressure	31	Bar	ID.4
HP steam temperature	260	ºC	ID.4
HP steam flow	40	kg/s	H.1 / H.2 / H.3
MP steam pressure	16	Bar	ID.4
MP steam temperature	220	ºC	ID.4
MP steam flow	40	kg/s	H.1 / H.2 / H.3

3.3 SECONDARY CIRCUIT: HEAT AND ELECTRICITY GENERATION

3.3.1 Secondary circuit proposed by ALSTOM

ALSTOM proposed a heat balance for the secondary circuit of a HTR cogeneration plant. The complete ALSTOM contribution is presented in Appendix B of the present report, and only the heat balance diagram of this secondary circuit is reproduced in Fig. 3-1 hereafter for information.

Although the design proposed by ALSTOM fits the requirements of the ARCHER project very well, it is oriented to a generic end user that would require high and medium pressure steam.

However, it has been decided in the later phases of the ARCHER project (Dresden meeting, April 2013) to design the cogeneration plant for a specific end user: the PROCHEM refinery and petrochemical complex. EA has thus made some modifications to the design proposed by ALSTOM in order to adapt it to the needs of the PROCHEM complex.

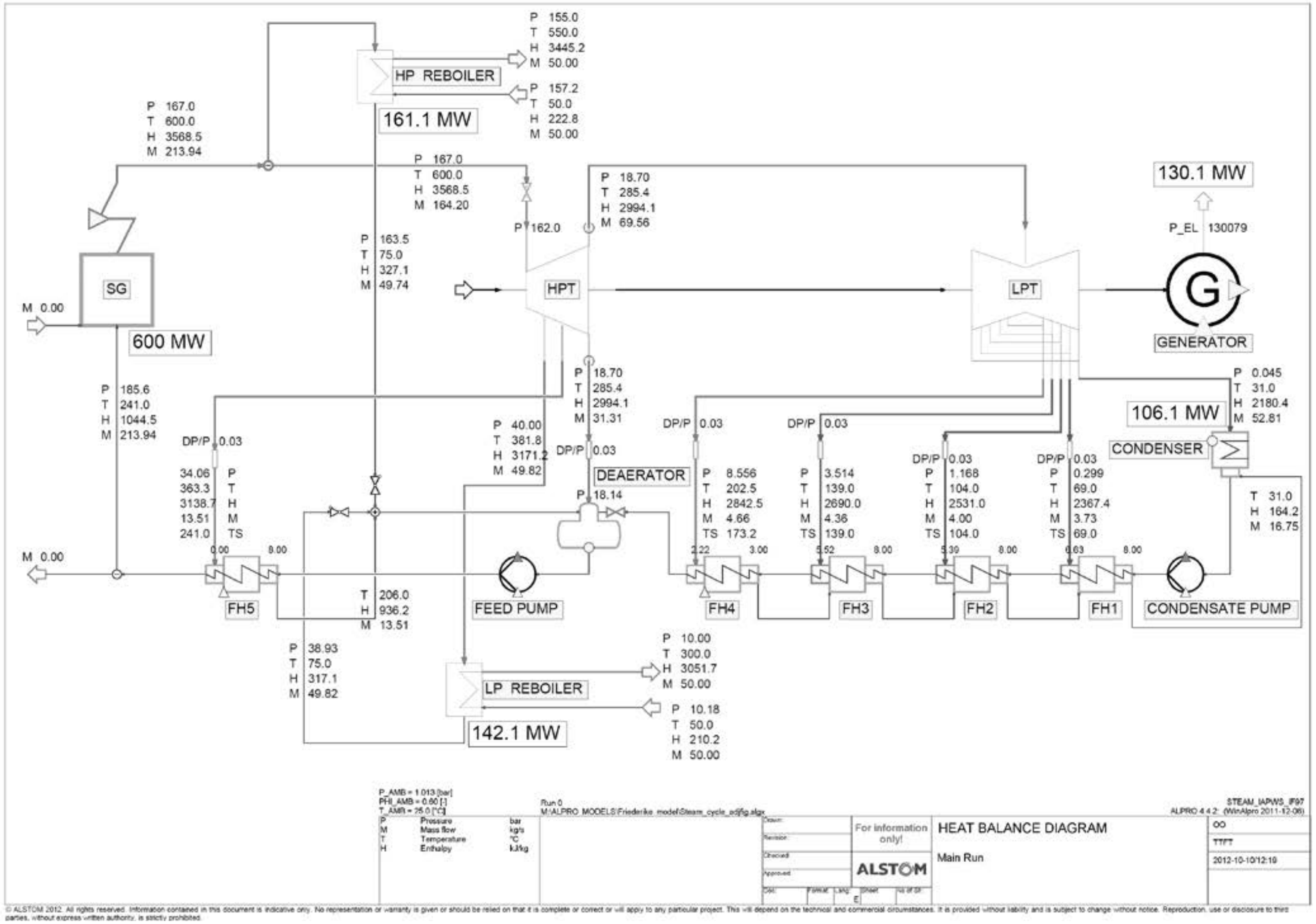

Fig. 3-1: Heat Balance of the secondary circuit proposed by ALSTOM

3.3.2 Secondary circuit configuration chosen by EA

The modifications made by EA to the ALSTOM proposal are listed and explained in the following sections. The data used in the thermal balance are sum-up in Table 3-2 hereafter.

3.3.2.1 Parameters imposed by the nuclear source

3.3.2.1.1 Thermal power

ALSTOM designed the circuit for total nuclear thermal power of 600 MW. However, Westinghouse proposed a design with a total thermal power in the primary circuit 520 MW (2 x 260 MW) so the secondary circuit design has been adapted to a nuclear power of 520 MW.

3.3.2.1.2 Main steam and feedwater conditions

The conditions and the flow of the feedwater and the live steam have been taken from the data provided by Westinghouse.

The data of the secondary circuit used as input in the heat balance are presented in Table 3-2.

Table 3-2: Secondary circuit data used as inputs in the thermal balance

Parameter	Value	Unit	Reference
Primary circuit thermal power	520	MW	ID.1
Feedwater flow at SG inlet	203	kg/s	ID.3
Feedwater pressure at SG intlet	240	bar	ID.3
Feedwater temperature at SG intlet	180	ºC	ID.3
Main steam pressure at SG outlet	190	bar	ID.2
Main steam temperature at SG outlet	530	ºC	ID.2

3.3.2.2 Parameters imposed by the end user

In the ALSTOM design, the steam is supplied at two pressure levels:

- High pressure: 155 bar and 550 ºC.
- Low Pressure: 10 bar and 300 ºC.

The steam conditions required by PROCHEM (ID.4) are much lower:

- HP: 31 bar and 260 ºC
- MP: 16 bar and 220 ºC

Thus, EA has made the following modifications to the cycle:

- The HP steam is not generated using live steam, but using a steam extraction from the HP turbine, in the following conditions: 60 bar and 357 ºC.
- The MP steam is generated using a fraction of the steam flow at the outlet of the HP turbine, in the following conditions: 41 bar and 315 ºC.

3.3.2.3 Parameters chosen by EA

3.3.2.3.1 Preliminary design of the reboiler units

In order to make the heat balance easier to understand, the reboiler units have been represented in EA's heat balance as single components with two input streams (steam from turbine extraction and cold water input from end user) and two output streams (condensate steam and process superheated steam for end-user).

In reality this unit is composed by several heat exchangers. For a better understanding, the sketch of the HP reboiler unit with the main parameters is presented in Fig 3-2 and Fig 3-3 hereafter. The reboiler units used for EA's thermal heat balance include the following components:

- An economizer (water/water heat exchanger) to bring the water close to the saturation temperature at the desired pressure.

- A kettle reboiler, where the steam from turbine extraction condenses on one side (shell side), and the water from the industrial user evaporate on the other side (tube side).
- A superheater (steam/steam heat exchanger) to bring the saturated steam at the outlet of the kettle reboiler to the conditions required by the end user.

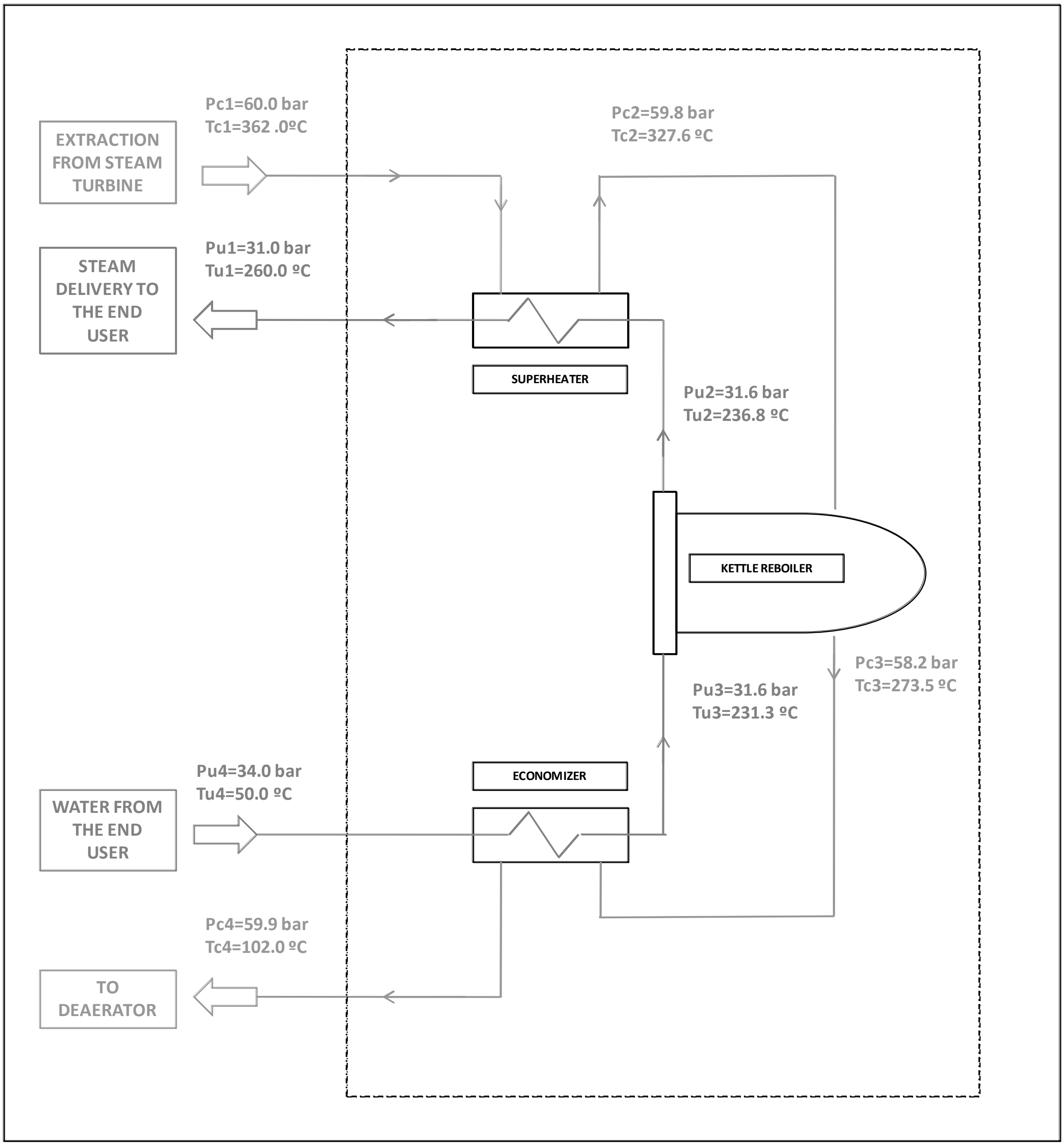

Fig. 3-2: HP Reboiler Unit simplified sketch

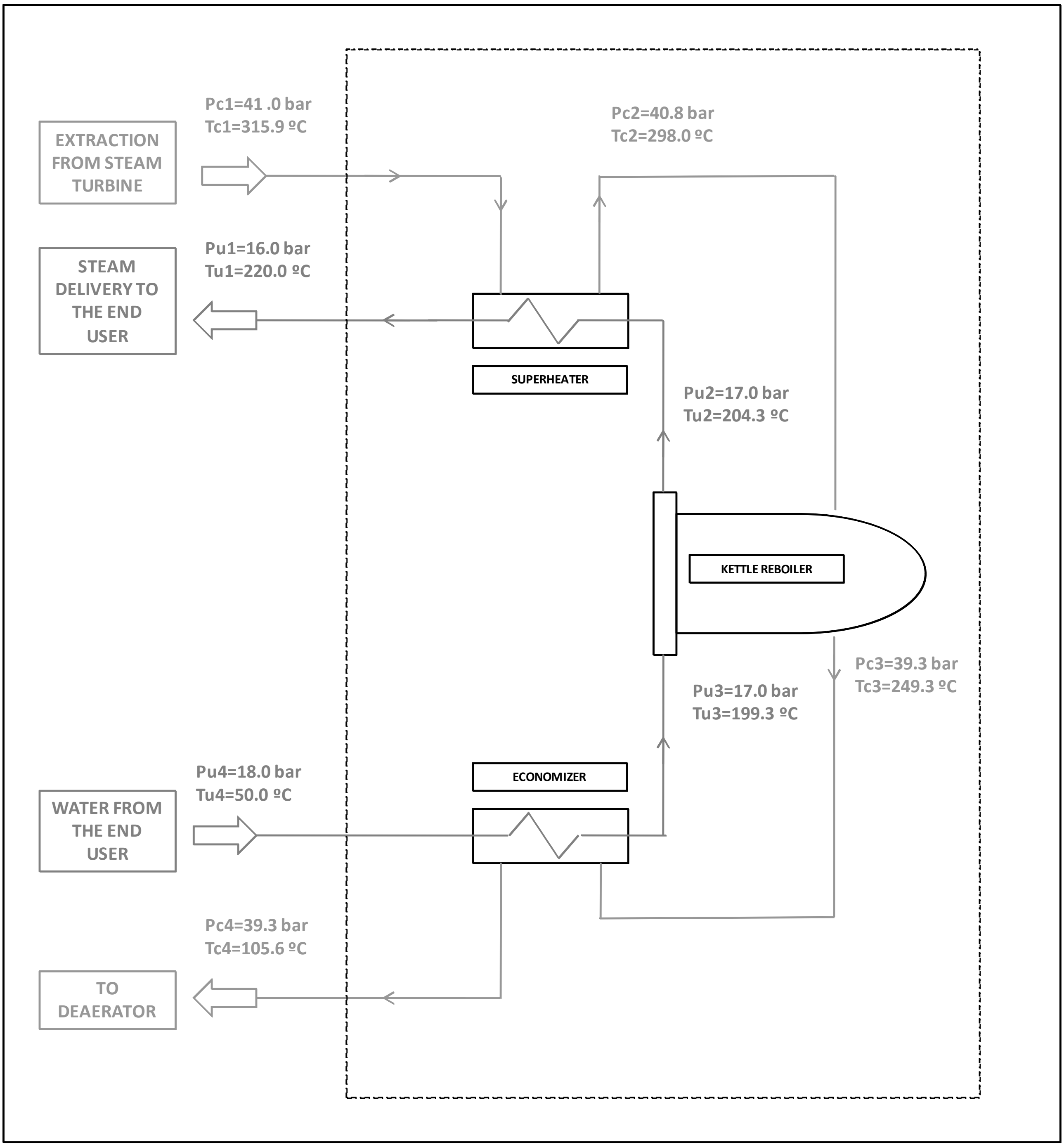

Fig. 3-3: MP Reboiler Unit simplified sketch

3.3.2.3.2 Main parameters for components

The main parameters of the components used in the thermal balance are the efficiency values. They are presented in Table 3-3.

Table 3-3: Components efficiencies and losses used in the thermal heat balance

Parameter	Value
Pressure loss in the main steam line and the HP Turbine governor valve (bar)	5,3
Feedwater heaters FWH1, FWH2 and FWH3 efficiency	0.97
Feedwater heaters FWH4 TTD (ºC)	1.65
Feedwater heaters (FWH1 to FWH4) DCA (ºC)	6
Deaerator efficiency	0.97
Pumps efficiency	0.73
LP Turbine isentropic efficiency	0.86
HP Turbine isentropic efficiency	0.89
Turbine / Generator efficiency[3]	0.98

[3] This coefficient is to take into account the mechanical losses in the turbines and the excitation power in the generator in order to calculate the generator gross electric output.

4. RESULTS: HTR COGENERATION PLANT HEAT BALANCE

4.1 THERMAL HEAT BALANCE

The ARCHER thermal heat balance is presented in Fig. 4-1 in the following.

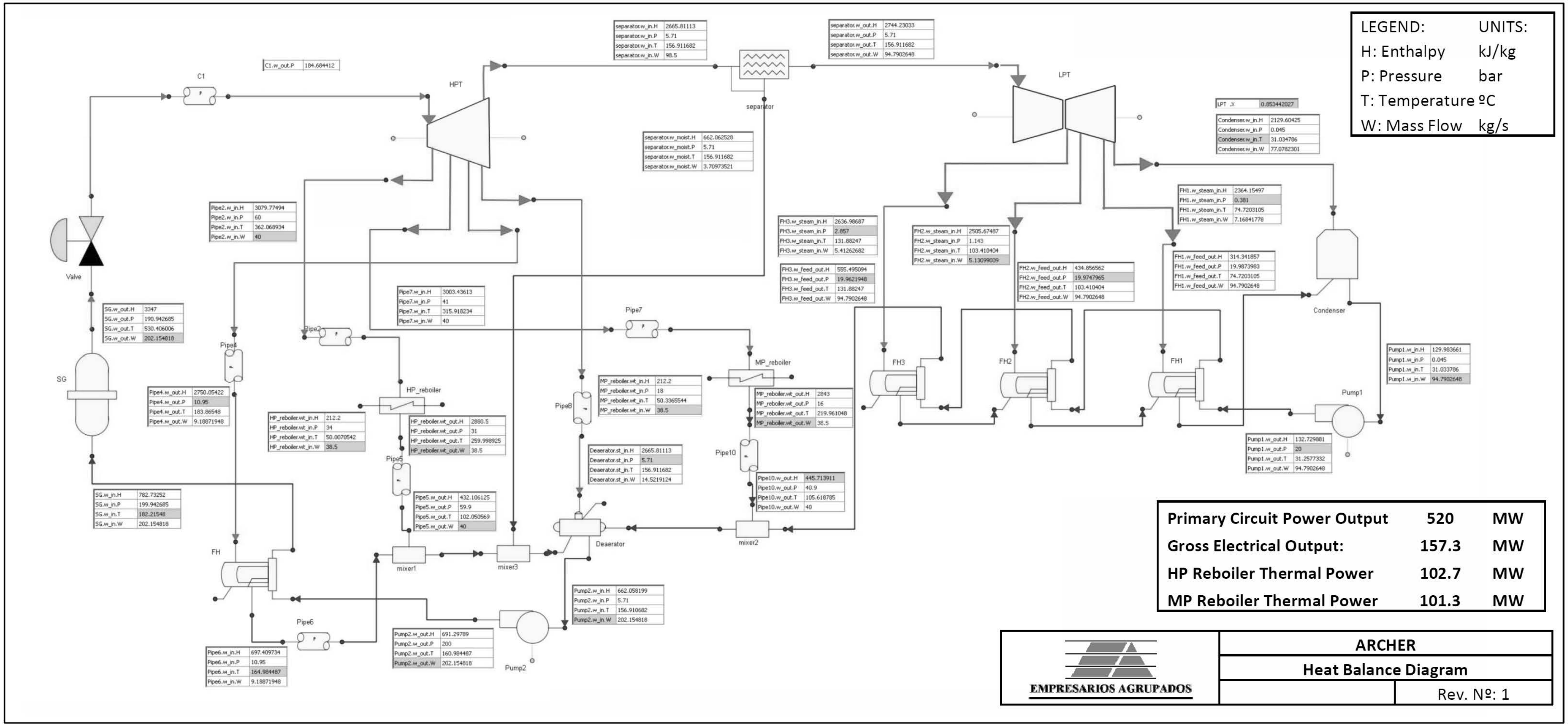

Fig. 4-1: ARCHER Thermal Balance

4.2 CYCLE EFFICIENCY

The main results are given in Table 4-2 hereafter.

Table 4-2: Main results of the ARCHER thermal heat balance

Parameter	Value	Unit
Gross Electrical Output W_{elec}	157,3	MW
Thermal Power Output Q_{output}	204,0	MW
Total System Efficiency	0,68	-
Effective Electric Efficiency	0,50	-

According to Ref.2, the following definitions for the efficiency of the cycle are used:

$$Total\ System\ Efficiency = \frac{W_{elec} + Q_{output}}{Q_{HTR\ core}},$$

$$Effective\ Electric\ Efficiency = \frac{W_{elec}}{Q_{HTR\ core} - \left(Q_{output} / \alpha_{SG}\right)}$$

(with α_{SG} being the Steam Generator thermal efficiency)

5. CONCLUSIONS

This document presents a thermal heat balance for a nuclear cogeneration plant, using two Pebble Bed High Temperature reactors as a heat source, producing electricity with steam turbines and producing steam at two different pressure levels in a tertiary cycle, to be supplied to an oil refinery and petrochemical complex.

This report thus provides an example, using real end user data (an oil refining and petrochemical complex) of how a HTR could be used in a cogeneration plant, which was one of the objectives of WP 1.1 of the ARCHER project.

There are several ways to calculate the efficiency of a cogeneration cycle, depending on how it is chosen to account for the heat produced. The results for two of the most common ways to calculate it are as follows:

- The Total System Efficiency (in which heat is seen as a final product in the same way as electricity) is equal to 68 %.
- The Effective Electric Efficiency (which gives the efficiency that the cycle would have if no heat was produced for external user) is equal to 50 %.

Although the cycle proposed does not take full advantage of the high steam temperatures that could be produced using the HTR technology (steam is produced at 31 and 16 bars) it provides a good example of a cycle that could be implemented with current technology.

However, regardless of the good efficiency results of the plant, it should be highlighted that the benefits for an industrial complex of using an HTR cogeneration plant is still unclear. In the case used in the present report for example (Prochem petrochemical complex), the entire cogeneration plant produces:

- 204 MW of steam, which is less than one of the seven boilers used to produce steam for the refinery complex (approximately 100 MW less).
- 157 MW of electricity, which is less than the amount of electrical power used in the refinery complex during winter (approximately 50 MW less).

To sum up, a nuclear power facility would have to be build close to an important industrial complex (thus probably adding difficulty to the licensing process), with the final objective of replacing one of the seven boilers used at the petrochemical complex. It goes without saying that the economic viability of the HTR cogeneration project will be one of the main challenges for that technology in the future.

6. REFERENCES

1) Ref.1: ALSTOM's contribution to ARCHER Task 1.1.3, doc nºTN12/xxxx, Olumide Olumayegun

2) Ref.2: "Methods for Calculating Efficiency", EPA.

http://www.epa.gov/chp/basic/methods.html

APPENDIX A

DESCRIPTION OF THE NUCLEAR HEAT SOURCE

(WESTINGHOUSE CONTRIBUTION)

Westinghouse

Document Category

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(Dept./Name)	(Dept./Name)	(Dept./Name)

HTR

EG0002.10/03

Westinghouse Electric Germany GmbH

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Abbreviations

ARCHER	Advanced High-Temperature Reactors for Cogeneration of Heat and Electricity R&D
AVR	Arbeitsgemeinschaft Versuchsreaktor
CCS	Concrete Cooling System
CVS	Central Ventilation System
DHR	Decay Heat Removal System
FE	Fuel Element
FIMA	Fissions per Initial Metal Atoms
HRB	Hochtemperatur Reaktorbau GmbH
HTR	High Temperature Reactor
HV	High Voltage
LEU	Low Enriched Uranium
LP	Low Pressure
LS	Live Steam
LV	Low Voltage
IP	Intermediate Pressure
HP	High Pressure
NSSS	Nuclear Steam Supply System
RB	Reactor Building
RAB	Reactor Auxiliary Building
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
SAS	Small Absorber Spheres
SG	Steam Generator

THTR	Thorium High Temperature Reactor
TRISO	TRi ISOstropic coated particle
VDU	Visual Display Unit
WEG	Westinghouse Electric Germany GmbH

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1 Introduction

This report constitutes the Westinghouse contribution to Work Package 11 (Coupled System Specification), Task 1.1.3 (Elaboration of Schematics and Case Studies) of the European research project “Advanced High-Temperature Reactors for Cogeneration of Heat and Electricity R&D” (ARCHER).

A nuclear heat source is described based on a Pebble Bed High Temperature Reactor (HTR) taking into account the boundary conditions from Task 1.1.1 and the Key Performance Indicators defined in Task 1.1.2. The report includes description and schematics of all relevant systems of the nuclear island. The resulting integral concept represents a nuclear island fitted to the requirements of the demonstration plant for nuclear process heat or co-generation.

An HTR is a universal heat source which can be applied for electricity generation as well as for process heat supply or co-generation of both. The German pebble bed HTR was developed and realized by Hochtemperatur Reaktorbau GmbH (HRB) now Westinghouse Electric Germany GmbH (WEG) in the frame of the AVR and Thorium High Temperature Reactor (THTR) projects in the 1960s and 1980s, respectively.

This type of nuclear reactor is characterised by high thermal efficiency, low waste heat, easy operation, continuous re-fuelling during power operation, low radiation dose to operating personnel, low radioactive releases to the environment, inherent safety as well as sustainable and flexible fuel cycle. Due to the high helium outlet temperature of about 700 °C and steam temperature of about 530 °C a large range of process heat applications can be covered by an HTR (Table 1-1).

Table 1-1: Overview of Potential Process Heat Applications for an HTR

Product/Industrial Process	Application	Required Process Temperature
De-salination of sea water		120 °C
Optimized oil production		300 – 500 °C
Processes for coal refinement:		
Coal gasification with steam	Production of Substitute Natural Gas (SNG)	700 – 750 °C
Hydro gasification	Production of Substitute Natural Gas (SNG)	~ 920 °C

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Product/Industrial Process	Application	Required Process Temperature
Hydrogen production:		
Methane splitting	Hydrogen production	750 - 850 °C
Coal gasification with steam	Hydrogen production	800 - 900 °C
Process steam for chemical plants (examples):		
Isopropyl benzene	Basis for phenol and acetone	250 °C
Polyamide production (e. g. nylon)		288 °C
Phenyl ethane		90 - 420 °C
Ammonia synthesis		400 - 500 °C
Process steam for refineries (examples):		
Atmospheric distillation	Liquid gas, light petrol, crude oil, Diesel oil, heavy oil	350 °C
Vacuum distillation	Vacuum gas oils, bitumen	350 °C
Thermal cracking	Hydrogen, methane, ethene, propylene, petroleum coke	450 - 800 °C
Reforming	Aromatic hydro carbons	500 °C

2 General Plant Overview

2.1 Overall Configuration

The overall configuration of the plant is constructed around a twin unit of two identical Nuclear Steam Supply Systems (NSSS). The main buildings of the plant are arranged in a compact group (Figure 2.1-1). The centrally located reactor building (1) is adjoined to the west by the reactor auxiliary building (2) and to the south by the switchgear and control building (4).

The fuel element storage building (3) is located to the west next to the auxiliary building. The turbine hall (7) to the east is connected to the reactor building via the intermediate building (6). The process heat building (8) with the outgoing pipelines is located on the east side of the turbine hall, with the air-cooled condenser building (9) on the north side. The de-mineralized water storage tank (11) is next to the turbine hall. The access control building (5), together with the office building attached to it, is located to the west of the switchgear building.

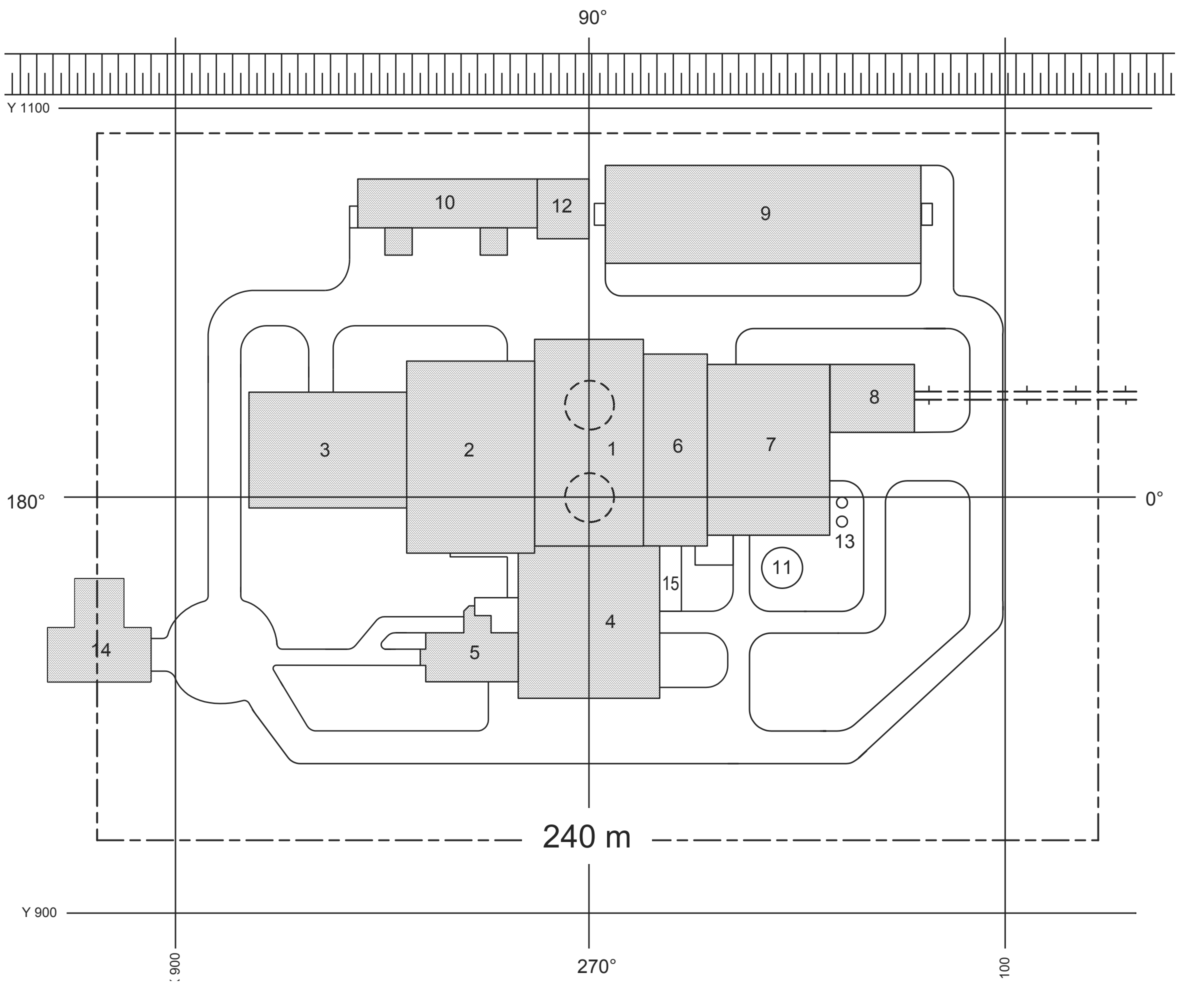

Figure 2.1-1: Main Buildings Ground Plan

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Compact cooling towers (10) and condensate cleaning system building (12) are placed in the north of the main complex.

This compact arrangement offers easy access to all buildings while minimizing the area of land required. The auxiliary and ancillary power plant systems are distributed over the power plant site as required for functional efficiency.

The canteen building and the store building are located in the south of the site. Access to the power plant site is monitored from the gate house (14). The space requirement for the plant is 240 m x 170 m.

The main characteristics of the NSSS are the steel pressure vessel, the pebble-bed reactor core with upward flow of the coolant gas, the steam generator located above the core, and control and shutdown using absorber rods immersed into the graphite reflector which encloses the core. The fuel element pebbles are re-circulated several times.

2.2 Nuclear Steam Supply System

The proposed NSSS is based on the HTR 100 industrial reactor concept and on the 15 MW AVR power plant at Jülich, which was designed and erected by Hochtemperatur Reaktorbau GmbH (HRB) now Westinghouse Electric Germany GmbH (WEG). During its operational phase it had an excellent operating record extending over more than 20 years.

The design characteristics of the NSSS are:

- Use of graphite as moderator and reflector
- Helium as the coolant
- Spherical fuel elements
- Integrated arrangement of all primary system components within a single steel pressure vessel
- Steel pressure vessel as pressure containment
- Steam generator with two helix bundles above the core
- Upward coolant-gas flow
- Two coolant-gas circulators with active magnet bearings
- Continuous refuelling with multiple circulation of fuel elements
- Control and shutdown by means of absorber rods
- Small absorber spheres as second shutdown system
- Decay heat removal via steam generator start-up/shutdown system, and auxiliary cooling water system, or via the concrete cooling system, in worst case by direct evaporation to the atmosphere.

The main design data of the NSSS are summarized in Chapter 2.4.

The reactor core is composed of a statistic fill of spherical fuel elements, the so called pebble bed. The reactor core has a diameter of 3.5 m and an average height of 8 m. The average power density is 4.2 MW/m³. The core is surrounded by a graphite reflector composed of bottom reflector, side reflector and top reflector. This unit is vertically arranged on a metal support structure, which is connected flexible to the reactor pressure vessel (RPV).

The fuel elements are added to the core from the top via 5 sphere charge tubes and removed from the core via 4 sphere discharge tubes at the bottom. The continuous re-fuelling scheme guarantees a high and homogeneous burn-up. Fuel elements which have reached their target burn-up are removed by the fuel handling system and replaced by fresh fuel elements. Fuel elements which did not reach the target burn-up are re-cycled to the top of the reactor core.

The average residence time of a fuel element inside the equilibrium core is 3 years. Target burn-up is ~100 GWd/t_{HM} or ~10 % FIMA. Control and shutdown of the reactor are performed by 24 control rods inside the graphite side reflector. 8 control rods are used for load following operation between 50 % and 100 % power. For long term cold shutdown additional small absorber spheres inside the graphite side reflector are employed (second reactivity control system).

The reactor core is operated at a pressure of 70 bar. Helium is conveyed from the bottom of the core to the top and is heated to 740 °C. After leaving the core the gas flow passes the top reflector and is mixed with bypass flow. Subsequently, the helium flow enters the helical coil steam generator from the bottom. The inlet temperature to the steam generator is 700 °C. Inside the steam generator heat is transferred from the primary flow to the secondary side and secondary steam is generated. During full power operation 260 MJ/s of heat are transferred and steam is generated at 530 °C and 190 bar. After passing the steam generator the helium flow enters two coolant gas circulators at 250 °C. From there the cooling gas is conveyed back to the bottom of the reactor core.

2.3 Safety Classes

The plant components are safety classified according to the following Table 2.3-1.

Table 2.3-1: Safety Classification of Plant Components

Plant Component	Safety Class
Reactor pressure vessel, including pipes carrying primary gas, with 1st stop valve	1
Depressurization equipment of reactor pressure vessel	1
Internals of reactor pressure vessel	
Ceramic internals	1
Metallic internals	1
Fuel elements	1
Shutdown equipment	
Reflector rods, including mechanical brake, eddy-current Brake, rotating drive parts in the "insertion" function	1
Reflector rod drives in regard to the "withdrawal" function	3
Small absorber sphere system	
Shutdown and primary coolant inclusion function	1
Return function	3
Coolant gas circulators	
Function	3
Pressure-stressed encasement	1
Steam generators	2
Cooling water systems	
Concrete cooling system, without closed circuit-cooling chain	1
Service cooling water system (primary and secondary)	3
Component cooling water system	3
Water/steam circuit	
Inside reactor building, including penetrations	2

Plant Component	Safety Class
Outside reactor building	3
Start-up and shutdown system	3
Ventilation system	
Supply/exhaust air and circulating air systems in monitored area	3
Supply/exhaust air and circulating air systems in switchgear building	3
Circulating air system for switchgear building (safety-relevant section)	1
Supply/exhaust air in turbine hall	3
Supply/exhaust air in condensate clean-up room	3
Supply/exhaust air in intermediate building	3
Depressurization system	1
FE storage building	3
Compressed air system	3
I & C equipment	
Reactor protection system	1
Accident instrumentation	1
Emergency control room	1
Central control room	3
Refuelling system (after 1st stop valve)	2
Inward transfer channel after 1st valve	3
Gas purification system (after 1st stop valve)	3
Gas analysis (after 1st stop valve)	3
Effluent treatment plant	3
Purified-helium store	3
Electricity supply system	
Emergency power supply	1
Remaining systems	3

2.4 Design Data

2.4.1 Main Design Data

Total Plant (2 x NSSS)		
Thermal reactor output	MJ/s	2 x 258
Thermal output of nuclear steam supply system	MJ/s	2 x 260
Electric power at generator terminals	MW	100 - 175
Auxiliary power	MW	20
Process steam at 16 bar / 270 °C	t/h	170 – 500
Design point (electric power / steam)	MW_{el} / t/h	127 / 400
Primary Circuit		
System pressure (circulator outlet)	bar	70
Circuit pressure loss	bar	1.35
Hot-gas temperature (SG inlet)	°C	700
Cold-gas temperature (SG outlet)	°C	250
Heat losses	MW	1.3
Helium mass flow, total	kg/s	111.2
Helium inventory	kg	1 700
Secondary Circuit		
Live steam pressure (SG outlet)	bar	190
Live steam temperature (SG outlet)	°C	530
Feed water temperature	°C	180
Condenser vacuum	bar	0.06
Air temperature (annual mean)	°C	20
Availability and Lifetime		
Service life	a	40
Mean utilization at full load	h/a	8 000
Attainable temporal availability	%	90

Reactor Plant		
Primary Circuit Data at Full Load		
Thermal output, reactor core	MJ/s	258.3
Thermal output, steam generators	MJ/s	260
Heat losses	MJ/s	1.3
Circulator shaft output, total	MW	3
Pressure (circulator outlet)	bar	70
Pressure losses		
Total circuit	bar	1.35
Reactor core	bar	0.70
Steam generators	bar	0.45
Gas guides	bar	0.20
Reactor Pressure Vessel		
Outer diameter max.	mm	6 115
Height, without circulators	mm	30 000
Design pressure	bar	70
Test pressure	bar	77
Reactor Internals		
Ceramic internals		
Overall height	mm	12 750
Diameter	mm	5 450
Wall thickness	mm	1 000
Ceiling thickness	mm	1 500
Bottom inclination	degrees	30
Max. dose at side reflector	n/cm^2 (EDN)	2.5×10^{22}

Metallic internals (thermal shields)		
Design temperature	°C	350
Side shield thickness	mm	50
Bottom shield thickness	mm	50
Sphere discharge tubes		
Number	-	4
Inner diameter	mm	500
Reflector rods		
Number	-	24
Travel distance	mm	8 500
Rod diameter (cladding tube/joints)	mm	85/95
Max. dropping speed	m/s	0.5
Max. withdrawal speed	m/s	0.07
Drive	electric motor	
Small absorber spheres		
Number of spheres		2.4×10^6
Sphere diameter	mm	9.5
Number of supply tanks		4
Fuel elements		
Particle type	-	TRISO
Outer diameter	mm	0.91
Core diameter	mm	0.50
Core material	-	UO_2
Heavy metal per fuel element	g	14.5
Radius of FE fuel matrix	mm	25
Radius of FE	mm	30

Fuel Circuit (LEU)		
Initial enrichment	weight % U	9
Mean burn-up	GWd/t U	99.4
Mean dwell time of FE (full load)	d	977
Moderation ratio	-	10 058
Excess reactivity	delta k	1.8
Reactor Core		
Helium inlet temperature	°C	255
Helium outlet temperature	°C	740
Coolant gas flow rate	kg/s	111.2
Core Bypass	%	7.5
Radius of active core	mm	1 725
Height of cylindrical core	mm	8 000
Core volume	m^3	60.86
Number of spheres	-	317 500
Loose bulk density of spheres	-	0.59
Mean power density	MJ/sm^3	4.2
Total inventory (equilibrium core)		
Heavy metal	kg	2 363
U235	kg	91
Pu 239	kg	10
Pu 241	kg	3

Circulators		
Number	-	2
Suction pressure	bar	68.6
Suction temperature	°C	250
Mass flow at 100 %	kg/s	55.6
Pressure boost	bar	1.37
Range of control, mass flow	%	15 – 103
Steam Generators		
Number of lines	-	2
Thermal output	MJ/s	260
Helium side		
Mass flow	kg/s	111.2
Inlet temperature	°C	700
Outlet temperature	°C	250
Pressure	bar	approx.69
Water/steam side		
Mass flow	kg/s	50.6
Feedwater temperature	°C	180
Live steam temperature	°C	530
Live steam pressure	bar	190
Tube outer diameter	mm	20
Central tube diameter	mm	1 240
Number of tubes	-	322
Tube length (bundle)	mm	12 760
Bundle height	mm	10 230
Bundle diameter	mm	2 740

2.4.2 Water Steam Circuit

Steam Generators		
Number of lines, total		4
Total thermal output	MJ/s	520
Mass flow, total	kg/s	202.4
Turboset		
Live steam pressure before turbine	bar	180
Live steam temperature before turbine	°C	525
Generator output	MW	127
Air-Cooled Condenser		
Condenser pressure	bar	0.06
Ambient air temperature (annual mean)	°C	20
Feedwater tank		
Pressure	bar	15
Temperature	°C	190
Feedwater Pumps		
Number	%	4 x 65
Drive output at shaft, total	MW	2.6
Delivery flow	kg/s	63

2.5 Process Engineering Design

2.5.1 Nuclear Steam Supply System

The technical concept and the arrangement of the primary system components in the reactor pressure vessel are shown in Figure 2.5.1-1. The main data of the NSSS are listed in the sections above.

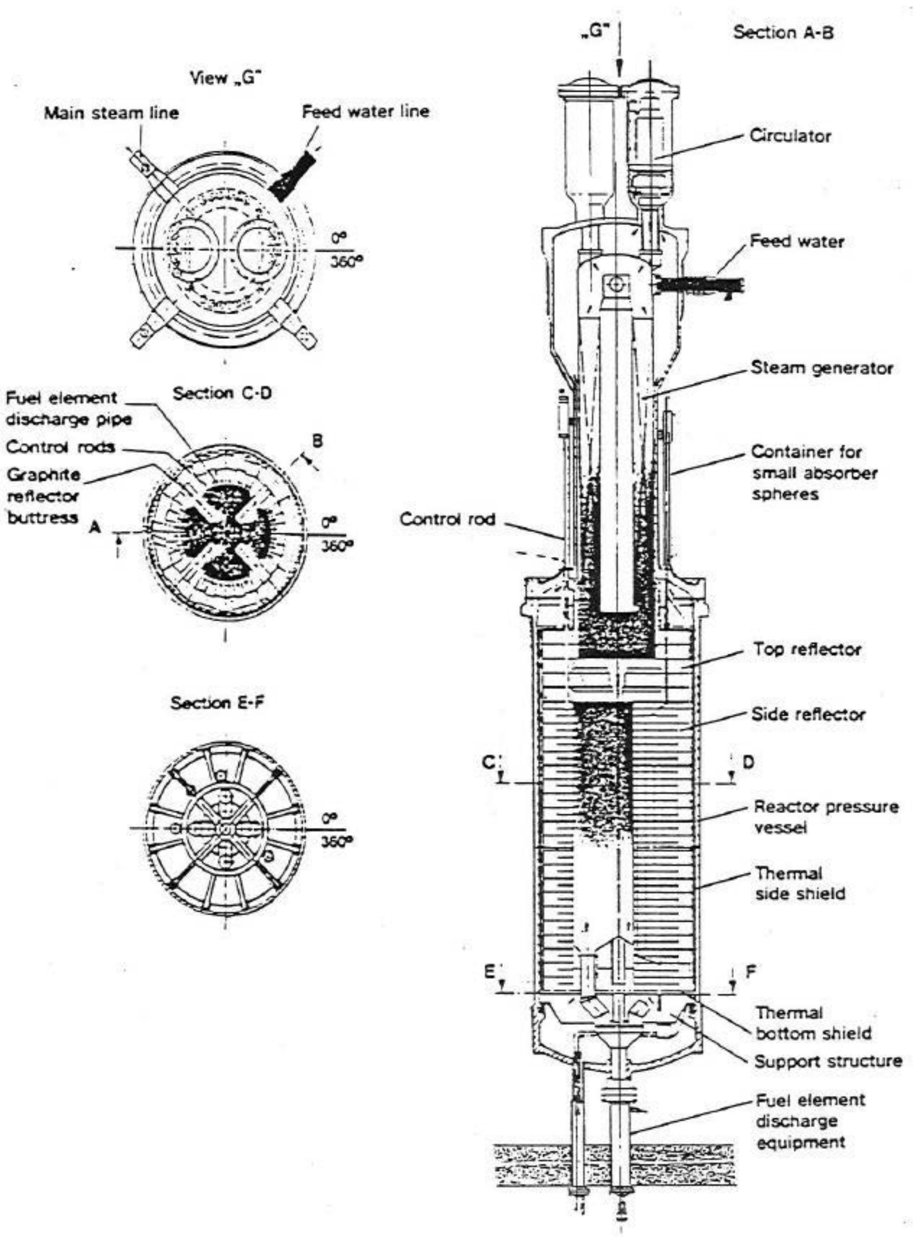

Figure 2.5.1-1: Nuclear Steam Supply System Cross and Longitudinal Section

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The reactor core is a cylindrical bed of spherical fuel elements, the pebble bed. It has a diameter of about 3.5 m, a mean height of 8 m, and a mean power density of 4.2 MJ/(s m^3). The reactor core is enclosed by a graphite reflector assembly composed of bottom, side and top reflectors. This assembly is mounted on a star-shaped metal structure which in turn is fixed to the reactor pressure vessel so as to permit thermal expansion but no rotation. The side reflector is laterally interlocked with the thermal side shield.

The fuel elements are continuously fed to the core through five refuelling tubes at the top and withdrawn through four fuel element discharge tubes below the core. Continuous fuel circulation ensures a high and even burn-up. Fuel elements already burnt up are discharged and replaced by fresh fuel elements; fuel elements not yet completely spent are circulated back to the core.

At a load factor of 0.9, the mean residence time of a fuel element in the equilibrium core is three years, with five passes through the core. The mean burn-up is 100 GWd per ton of heavy metal.

A total of 24 absorber rods are provided for reactor control and scram. Eight absorber rods are used for load-following control of the reactor between 50 and 100 %. For long-term shutdown and cool-down of the reactor, small absorber spheres (9.5 mm diameter) are dropped into vertical channels in the buttress-like protrusions of the side-reflector inner wall.

The helium gas coolant flows upward through the reactor core at a pressure of 70 bar. The hot helium leaves the core at about 740 °C, flows through openings in the top reflector, and mixes with the various bypass flows, which results in a mean temperature of 700 °C at the steam generator inlet. The helium flow through the steam generator is upward. Rated thermal power of the steam generator is 260 MJ/s. Live steam is generated at 530 °C and 190 bar; lower pressures are feasible. The helium coolant enters the two circulators at a cold gas temperature of about 250 °C. The circulators force the coolant through the annulus between pressure vessel and steam generator or core, respectively, and into the lower part of the reactor pressure vessel, where the cold gas enters the pebble bed through openings in the bottom reflector, cooling on its way the pressure vessel wall, the thermal shield, and the side reflector.

Reactor pressure vessel material is the proven steel type 20 MnMoNi 55 which is widely used in nuclear reactors.

The steam generator consists of two separate tube bundles arranged in a single unit of concentric helicoils. The circulators are single-stage radial blowers with active magnetic bearings, mounted on the top head of the pressure vessel.

2.6 Control Concept and Operating Modes of the Power Plant

2.6.1 Control Concept

The plant is designed for co-generation of industrial steam and electricity (Figure 2.6.1-1). Industrial steam is generated at 270 °C and 16 bar. The steam mass flow can be varied between 170 t/h and 500 t/h. In addition the turboset can generate between 60 MW and 170 MW of electricity.

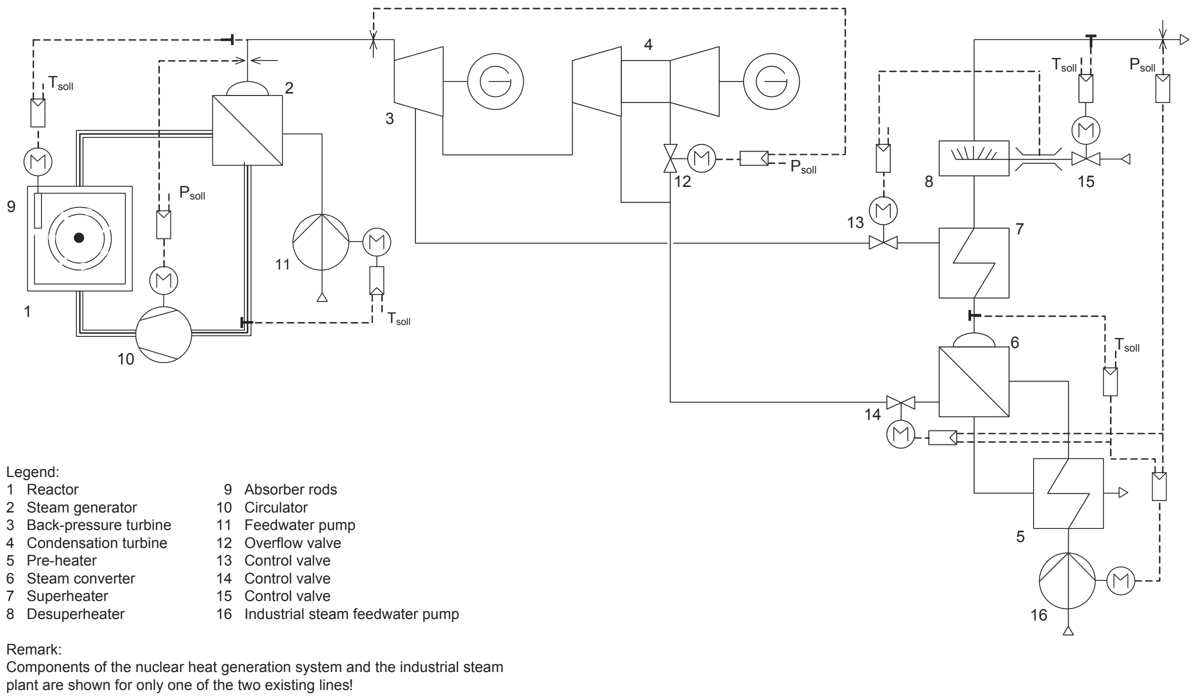

Figure 2.6.1-1: Control Scheme

The control concept for the twin-unit plant corresponds to that for plants with one reactor. The live steam temperature of both reactor systems is controlled to the same value, as is the live steam pressure.

At partial plant load, there are two possible modes for the reactors:

- Both reactors run at partial load
- One reactor runs at full load, the other with partial load.

The mode is determined by the load requirements. Parallel operation of the reactors is to be preferred when relatively small load fluctuations must be corrected quickly. The output of the two reactors can be varied in the range between 100 % and 50 %.

Fast shutdown of a reactor due to disturbances in its nuclear steam supply system does not lead to a failure of the other reactor. Likewise, trip-out of the turbo set does not involve any fast reactor shutdown.

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2.6.2 Cold and Warm Start

For start-up from cold condition, the heat is condensed in the start-up and shutdown system up to the end of the wet-steam phase, which lies at a live steam temperature of 300 °C. It is then fed to the air-cooled condenser, which serves as a heat sink. After a reactor power of 50 % has been reached at about 60 % coolant mass flow, the turbine is started up at a live steam pressure of 85 bar and a live steam temperature of 350 °C.

From a live steam temperature of 450 °C upwards, the live steam pressure can rise from 85 bar to 190 bar with a gradient of 3.5 bar/min, the live steam temperature with a gradient of 1.3 K/min. In the case of a warm start (which is performed within 72 hours after reactor shutdown and in a procedure which is similar to a cold start), the start-up time to full load is reduced, since warm-up periods can be dispensed with. The still-warm turbine requires a live steam temperature of about 450 °C for start-up.

2.6.3 Shut Down

The normal shutdown procedure is used for planned shutdown of the system. The reactor power is reduced, causing the electricity generation to go to partial load. After the power level has sunk to 50 % at one or both reactors, the turbine is shut down. At a live steam temperature of 300 °C and a live steam pressure of 80 bar, the start-up and shutdown system becomes operative. Once the steam generator temperature has dropped to 250 °C, the plant decay removal function commences.

In the case of rapid shutdown (scram) triggered by disturbances, the shutdown procedure does not take as long as with normal shutdown. It is initiated by dropping the reflector rods. In the normal shutdown procedure, these are inserted slowly, so that the hot-gas temperature drops by about 5 K/min.

2.7 Safety Concept

2.7.1 Principles of Safety Precautions

It is the generic aim of the safety measures to realize the design, construction and operation of the plant in such a way that taking into account the current state of science and technology, the load of the operating personnel and the environment from radioactive radiation is low enough during normal operation as well as under accident conditions.

To achieve this aim it has to be ensured that at any time safe shutdown of the reactor, maintenance of the shutdown condition, decay heat removal and activity confinement are ensured.

For this purpose the following principles have to be observed:

1. Plant operation oriented to plant safety. To this end the following conditions are required:
    - Competent and reliable personnel

- Sufficient training of personnel
- Simple process design
- Ergonomic design of the control facilities (control room)

2. Early detection of malfunctions and information about the sequences by which the malfunctions may develop into accidents. Suitable measures for this purposes are:
   - Detailed analysis of the plant behaviour
   - Detection and limitation of leakages
   - Monitoring of activity
   - Slow change of process variables by self-stabilizing feedback
   - Simple, clear and reliable control as well as signalization of the plant conditions

3. Graduated measures for accident control furnished by:
   - Multiple barriers for activity confinement
   - Diverse modes of decay heat removal
   - Sufficient measures for reaching the cold subcritical condition
   - Safe electricity supply

4. Further measures for limitation of damage, including:
   - Protection against external impact
   - Protection against internal impact
   - Protection against fire and explosion
   - Manual measures for limitation of damage

2.7.2 Reactor Shutdown

For complete interruption of the chain reaction in the reactor core, two diverse systems are provided:

- 24 absorber rods located in the side reflector (first shutdown system)
- Small absorber spheres (SAS) released into channels in the buttress-like protrusions in the reactor core (second shutdown system). This system is alone capable of keeping the reactor subcritical indefinitely.

8 out of the 24 absorber rods are reserved for control during normal operation. They meet all reactivity requirements for load-following operation between 50 and 100 %. The remaining 16 absorber rods are provided for reactor scram. They are normally fixed in their upper-end positions. Upon reactor scram, they are electrically released and drop by gravity.

After accidents without reactivity increase, the reactor can be left subcritical for any time desired, with the core near operating temperature. If the core is cooled down, additional shutdown reactivity is required after about 30 hours, because of the xenon decay. This requires actuation of the second shutdown system. This is done by hand, since at ambient temperature the reactor will become critical again at only a few per cent and, with the xenon decaying, power rises only slowly.

In the event of accidents with reactivity increase, e.g. water ingress or erroneous operation of absorber rod groups, the absorber rods compensate the accident-induced reactivity increase. In the long run (> 24 hours), the xenon decay again requires release of the small absorber spheres.

2.7.3 Decay Heat Removal

The decay heat can be removed from the primary system in two independent and diverse ways:

1. Via steam generator, start-up/shutdown system, and auxiliary cooling water system.
2. Via the concrete cooling system (in worst case with direct evaporation to the atmosphere).

Decay heat is removed via the start-up/shutdown system for normal shutdown and after reactor scram following plant malfunctions. Because of its high availability, this system will also be used for most accidents. The shutdown procedure using the start-up/shutdown system protects the components against frequent thermal stresses. For normal shutdown of the plant, the power generated in the nuclear steam supply system and the steam/feedwater circuit is slowly reduced from 100 % to about 10 % (Figure 2.7.3-1).

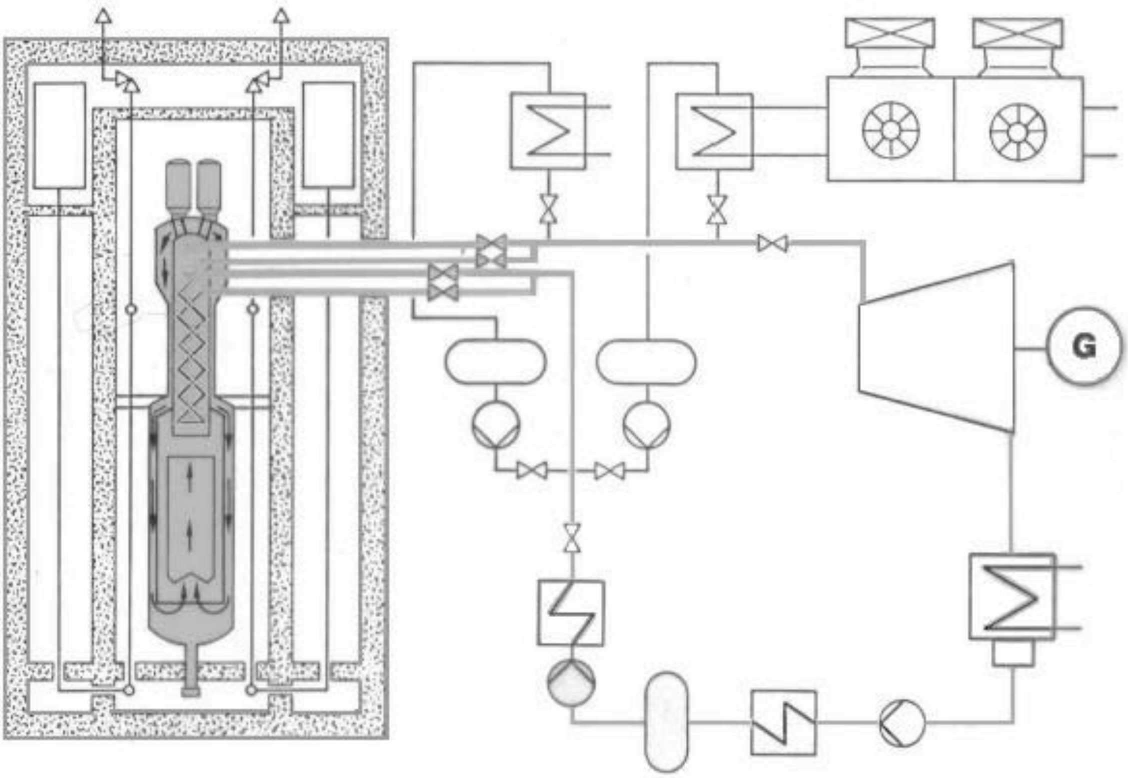

Figure 2.7.3-1: Flow Diagram Water-Steam Cycle in Normal Operation

After switch-over to the start-up/shutdown system, the steam is condensed in the auxiliary condenser, which in turn is cooled by the auxiliary cooling water system (Figure 2.7.3-2). The condensate is re-circulated to the steam generator through the feedwater lines. This operation is maintained (also in the subsequent water phase) until the plant is restarted or the decay heat has diminished to a level where the reactor can be kept in the cold subcritical state without active cooling.

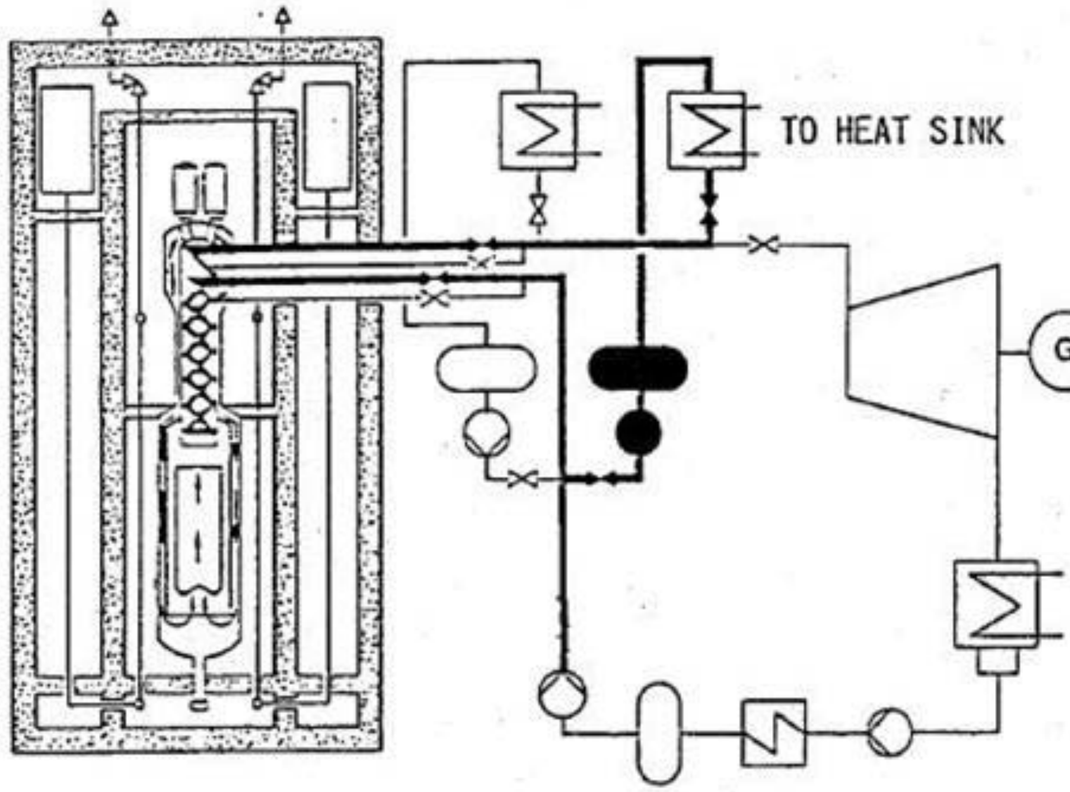

Figure 2.7.3-2: Flow Decay Heat Removal via Start-Up/Shutdown System

After a reactor scram, decay heat is removed either in the same manner, or, if the normal path is unavailable, directly via the start-up/shutdown system. Upon failure of both circulators, the heat transfer from the reactor core to the steam generator by natural convection is sufficient for heat removal by the start-up/shutdown system, due to the arrangement of the steam generator above the core. The high heat capacity and the low power density of the NSSS even permit a limited interruption of decay heat removal so that sufficient time is available for taking appropriate manual action.

Following the rare events resulting in failure of the start-up/shutdown system, the decay heat is removed via the concrete cooling system. After external events resulting in complete loss of power, and therefore loss of all pumps, this system still operates in the evaporation mode (Figure 2.7.3-3).

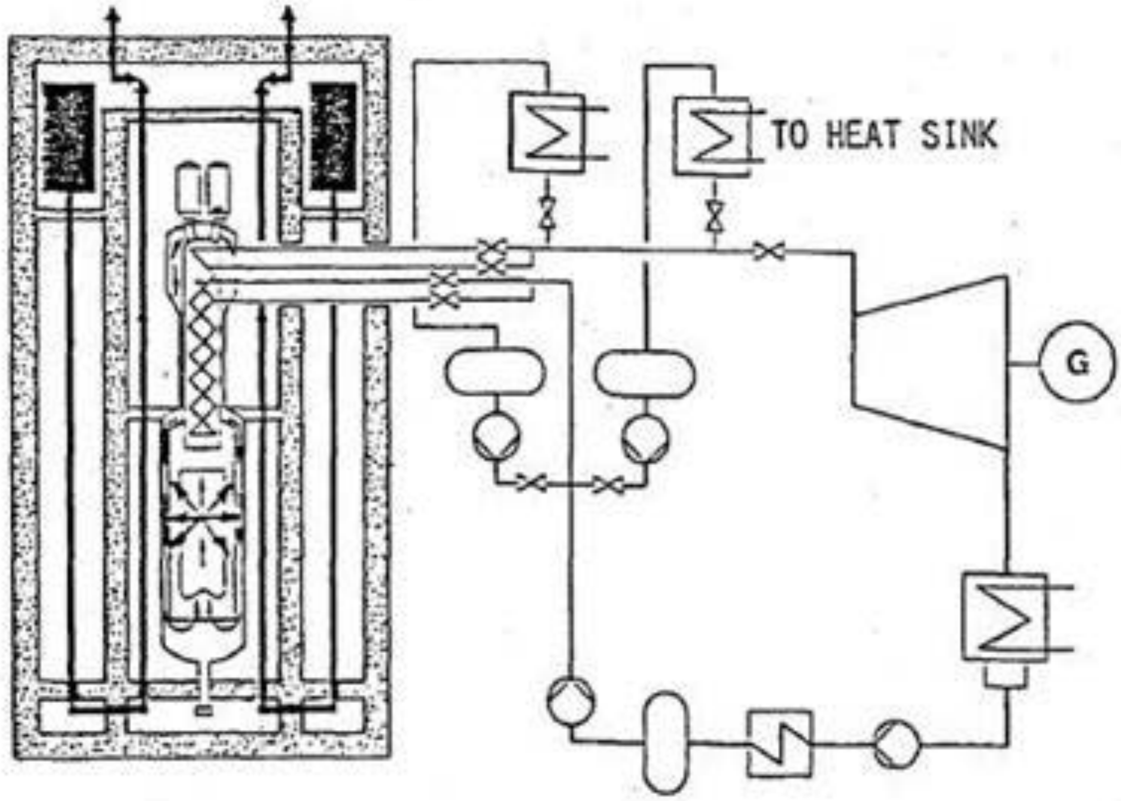

Figure 2.7.3-3: Decay Heat Removal via Concrete Cooling System

Even if, in addition, depressurization of the primary coolant system is assumed, the maximum core temperatures stay well below the limit where the fission product retention capability of the fuel elements starts to weaken (Figure 2.7.3-4). Thus, even in this worst case, there is no significant release of radioactivity.

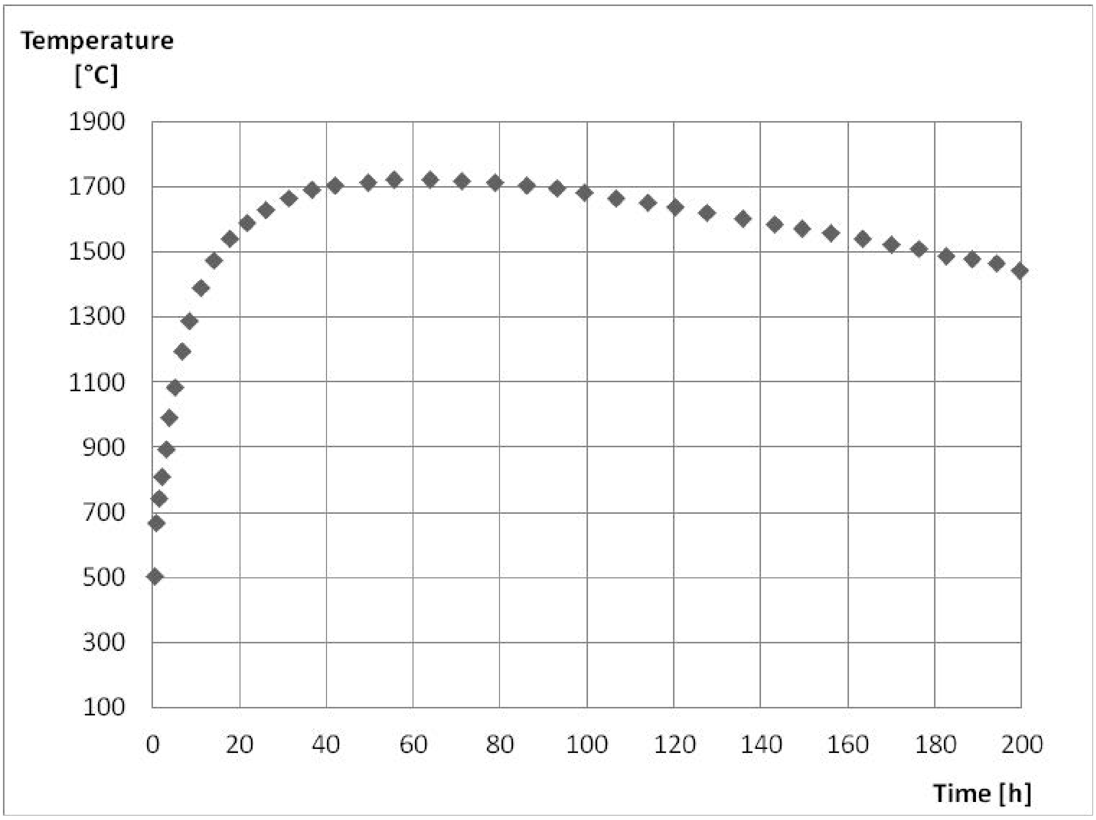

Figure 2.7.3-4: Maximum Core Temperatures after Depressurization

The decay heat removal of the NSSS is simple and for the worst cases, inherently safe. Few components are needed and little instrumentation and control equipment. All components of the reactor protection system needed, together with the related switchgear and power supply, are located in the reactor building protected against external events.

2.7.4 Protection against External Events

All plant components required for shutting down the reactor, for reliable decay heat removal, and for activity containment in the event of external accidents (earthquake, plane crash and gas-cloud explosion), are designed, configured and protected so that they can safely fulfil their safety-engineering tasks.

These plant components are located in the reactor building, which is designed to withstand external events, thanks to appropriate dimensioning of the outer wall and decoupling of the internal structure. The reactor auxiliary building is designed to resist earthquakes, and possesses a leak proof sump to prevent radioactive waters penetrating into the soil. The fuel element storage building is designed to resist external events, the switchgear building to resist earthquakes.

2.7.5 Activity Containment

The radiation exposure for the environment is in normal operation especially low, and is far below the permissible values, since the fission products are retained in the coated fuel particles, i.e. at the location of their formation, and by other barriers inherent in the system.

During normal operation, the radiation exposure for the environment is about 0.01 mSv/a. In the event of accidents, even those with core heat-up, the permissible temperature limits for the fuel elements are not exceeded. Although the low release rate of fission products would always permit unfiltered release of the building air to the surrounding atmosphere, the coolant is nevertheless passed almost entirely through highly effective filter systems, and in all cases monitored as it is released into the surrounding atmosphere via the stack. The radiation exposure for the environment remains in the event of accidents far below the limit values legally permitted.

2.7.6 Inherent Safety Characteristics of HTR

By realizing these principles the great safety potential is used which is offered by nuclear power plants with high-temperature reactors due to their inherent characteristics enhancing the safety.

These inherent safety characteristics of the HTR are based on physical laws which in concurrence with a suitable design, core structure and the use of high-temperature resistant materials intensify and partly replace the functions of active and passive engineered safety systems.

The HTR-specific safety characteristics ensure a highly good natured and safe operating and accident behaviour.

The HTR's principle inherent characteristics are the following:

- Negative temperature coefficient of reactivity effecting self-stabilization and limitation of reactor power
- Low power, low power density, high core surface area and high heat capacity for inherent decay heat removal
- Modern TRISO coated particle fuel for safe retention of fission products even under severe accident conditions
- Full ceramic (graphite) core structure and fuel elements ensuring mechanical resistance to high temperatures up to about 3500 °C
- Low ration of power density to heat capacity resulting in a slow rise of the fuel element temperature under accident conditions
- Inert, phase-stable gaseous coolant (helium) ruling out total loss of coolant

In the following the inherent safety characteristics are discussed in detail.

2.7.6.1 Negative Coefficient of Temperature

The negative coefficient of temperature has the effect of stopping the nuclear energy production in case of temperature increase. Due to this effect the reactor shuts itself down without intervention of active shutdown systems. Provided they are appropriate designed, a negative temperature coefficient becomes effective also in other reactor types. As opposed to those reactors, the HTR fuel elements and the entire primary system are, however, capable of withstanding without damage the temperature increase necessary for automatic shutdown in the event of cooling failure. A temperature increase of less than 100 °C is sufficient for automatic shutdown so that in the event of failure of the cooling system the temperature dependence of the reactivity is available as an "inherent" shutdown mechanism in addition to the scram system. Thus even reactivity accidents can be controlled without damage to the fuel elements.

It has to be emphasized in this context that the fuel element temperatures in the HTR are substantially lower during power operation than for example in the light water reactor. In the proposed HTR they are about 1000 °C, being thus far below the temperatures permitted under accident conditions. Only a small fraction of the fuel element inventory is heated to such maximum temperatures. The greater part of the fuel elements have a mean temperature of about 700 °C.

2.7.6.2 Ceramic Core Structure and Fuel Elements

Core structure and fuel elements are composed of graphite having a sublimation temperature of about 3500 °C, which together with the high heat capacity of graphite allows for an unproblematic storage of large amounts of heat. This results in a very slow temperature rise when heat removal fails totally. Even under accident conditions the temperatures remain far below the failure temperature of the graphite components.

Retention of the fission products is also ensured up to temperatures which are high in relation to operating and accident temperatures. The fission products are almost completely retained within the coated particles up to about 1800 °C, noticeable damage to the coated particles would only occur at temperatures above about 2000 °C. However, due to the low power, low power density, high thermal mass and high surface area of the core only temperatures of about 1700 °C are reached in case of a Depressurization Accident with Loss of Forced Cooling.

In contrast to the LWR, a core meltdown accident is ruled out because the fuel elements are resistant to high temperatures. Therefore serious damage to the reactor vessel is not possible either. The small amount of fission products released from the small number of fuel elements heated up to elevated temperatures in the hypothetical event of a core heat-up accident in the HTR will be deposited largely on the colder surfaces within the primary system. The possibility of cooling the reactor core remains intact and the consequences for the environment are relatively low.

2.7.6.3 Low Ratio of Power Density to Heat Capacity

The power density in an HTR is very low compared to other reactors, being 4.2 MW/m^3 in the NSSS. Therefore the heat capacity: power density ratio is higher by a factor of 10 to 15 than for example in the LWR. The high heat capacity of the HTR core structure remains intact even in the event of a depressurization accident. Therefore disturbances between heat production and heat removal result in extremely slow temperature transients.

The rate of temperature change in the HTR is about 1 - 2 °C/min in case of cooling failure and depressurization (for comparison: in the event of total loss of coolant in the LWR this value may reach up to 500 °C/min) and the maximum temperature even in case of a depressurization accident with loss of forced cooling is circa 1700 °C. This is well within the tested limits of modern TRISO coated particle fuel and will not lead to significant release of fission products. Total loss of coolant is impossible in the HTR.

The coolant pressure of 1 bar which is established in a depressurization accident is sufficient to ensure minimum cooling together with heat conduction and heat radiation. Damage to the fuel elements does not occur. Very simple and uncomplicated systems can therefore be used for heat removal.

2.7.6.4 Activity Containment Concept

The activity containment concept is based on the multi-barrier principle.

- Fuel element
- Containment of reactor coolant (primary circuit)
- Safety containment (reactor building)

The spherical fuel elements made of graphite contain the fuel in the form of coated particles which are embedded in the graphite matrix. In contrast to the THTR the fuel kernels are coated with an additional intermediate SiC coating (TRISO particle). The SiC coating presents an effective retention barrier for the fission products including Cs-137, Cs-134, Sr-90, I-131 and even the highly mobile Ag-110. In addition, the TRISO particles cause a further reduction in the uranium contamination of fuel elements whereby in particular the release of inert gases and halogens into the reactor coolant can be reduced.

The second barrier is formed by the primary circuit which is the boundary for the reactor coolant. The necessary penetrations are closed by vessel closures, the seals of which are monitored so that any leakage can securely be detected.

Primary gas-containing piping which penetrate the primary circuit are designed fail-safe and supplied with shutoff valves. The shutoff valves are automatically closed by the plant protection criteria "reactor building activity too high" and "reactor building pressure higher than atmospheric" (penetration closure system).

The primary circuit is furnished with a redundant pressure relief system (safety valves) to limit pressure and prevent excessive stresses.

The primary circuit and auxiliary facilities containing primary gas are housed in the reactor building (safety containment) which protects them against effects from external events and also protects the environment from radiological accident effects. The reactor building has also a filtered pressure relief system which limits the internal pressure to permissible values. The reactor building pressure relief system will only be required during very improbable events (failure of a vessel closure).

2.7.7 Severe Water Ingress

Accidents resulting from water ingress into the reactor core are of subordinate importance for evaluating the residual risk of an HTR. This has been confirmed by all HTR risk analyses. Normally the water quantity penetrating into the core is automatically limited and the reactor is shut down. The water ingress accident is controlled even in the hypothetical event of failure of safety systems. A combination of these accidents with simultaneous failure of all active safety systems is, however, not be considered as reasonable, because of its low contribution to the risk.

Major effects upon the environment in case of water ingress accidents can be sufficiently controlled either by decay heat removal from the core and reactor shutdown, or by limiting the water quantity penetrating into the core. Rapid action is not required under such conditions. There are always several possibilities available for all safety functions mentioned. The safety functions for decay heat removal and plant shutdown have already been explained above. Limitation of the water ingress can be also effected by several various measures such as e.g. shutdown of the feedwater pumps or shutoff of the feedwater lines. This can be implemented by means of several valves either automatically or manually.

The pressure of the primary system, which increases by the water penetrating into the system, is limited to permissible values. The corrosion of graphite is also kept to permissible values by limiting the amount of water ingress or by cooling the core. Considering the strength of the ceramic internals, the graphite corrosion is low. The fission product retention capacity of the fuel elements is not impaired by the graphite corrosion either. In principle, all events of this type are covered by the core heat-up accident.

2.7.8 Severe Air Ingress

Similarly to water ingress an accident involving massive air ingress cannot result in a severe release of fission products. Since the fuel elements have an outer fuel-free layer of 5 mm thickness, only long-term air ingress at high temperatures could endanger the confinement of activity. A self-sustained long term reaction resulting in increased graphite corrosion requires not only temperatures above 1000 °C but also ingress of sufficient oxygen to produce more heat than is removed. This is, however, technically ruled out in the HTR. The ingress of such large quantities of air is prevented by the following plant-specific features:

- The fuel elements are enclosed in the pressure-proof and gas-tight confinement of the reactor vessel

- The large penetrations to the primary circuit are covered by closures in a fail-safe manner
- The smaller penetrations are either of a small diameter or equipped with structurally independent flow restrictors ensuring that even in the event of failure of the vessel closures only a small opening is set free

Even if any cooling failed for a longer period, the integrity of the reactor vessel would remain intact so that consequential damage resulting in major air ingress can be ruled out. It is therefore technically impossible that penetrations are opened in the reactor vessel whose disposition would permit a stack draft through the core.

The air ingress would additionally be limited by the reactor building whose integrity is not impaired by the accident.

3 Reactor Core and Shutdown Facilities

Thermal power is generated in the fuel elements of the reactor core by nuclear fission of the uranium. Reactor power is controlled by absorber rods in the side reflector. Using these absorber rods together with the second system utilizing small absorber spheres nuclear chain reaction can be permanently stopped and the reactor core can be cooled down to ambient temperature.

Core design is characterized as follows:

- The reactor is operated with a low enriched uranium fuel cycle (LEU).
- The power density is 4.2 MW/m^3.
- The spherical fuel elements are continuously added to the core during power operation, pass through the core by gravity, are re-circulated into the core four times and are discharged after five passes through the core. Additional graphite elements are continuously re-circulated without being exchanged.
- A burn-up measurement facility permits determination of the burn-up of a fuel element after each pass.

3.1 Core Design

The reactor core is a cylindrical bed of spherical elements. It has a diameter of 3.45 m and a mean height of 8 m. The core is enclosed by graphite reflectors four buttress like graphite protrusions reach laterally into the core (Figure 3.1-1). Each buttress has a long vertical channel into which absorber spheres (SAS) are released for long term shut-down. For power control 8 absorber rods are provided which move in vertical bores in the side reflector. Four fuel element discharge tubes in the bottom reflector ensure an even flow of the spheres.

The helium coolant flows upward through the core (inlet temperature 255 °C, mean/maximum outlet temperature 740 °C/767 °C). To obtain maximum uniformity of coolant gas exit temperature the core is divided into two zones, the so-called inner and outer zones. The reflector buttresses are surrounded entirely by the inner zone only (Figure 3.1-1). By appropriate arrangement of the fuel feed tubes and by suitable distribution of the circulated elements with different burn-up the core builds up with the inner zone having a lower fissile content than the outer zone. The cross-sectional area of the inner zone is about 60 % of the total core cross section.

The initial core is built up in two zones with exactly the same cross sections as the equilibrium core, so that the transition from initial to equilibrium core will not present any problems.

For equilibrium core re-fuelling only one type of fuel element will be used with a uranium content of 14.6 g. The fissile material enrichment is 9 %. In addition to the fuel elements, the equilibrium core contains 45 % of pure graphite elements without heavy metal. At full power operation (258 MW thermal) the core has a mean power density of about 4.2 MW/m^3. At a load factor of 0.9 the mean residence time of the fuel elements in the equilibrium core is 1086 days. During this period they pass

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through the core five times reaching a mean burn-up of 99 GWd per ton of heavy metal.

To refuel the equilibrium core about 180 fuel elements are required per day at full power. The graphite elements will be recirculated during the entire reactor life.

Further data at the equilibrium core are compiled in Table 3.1-1.

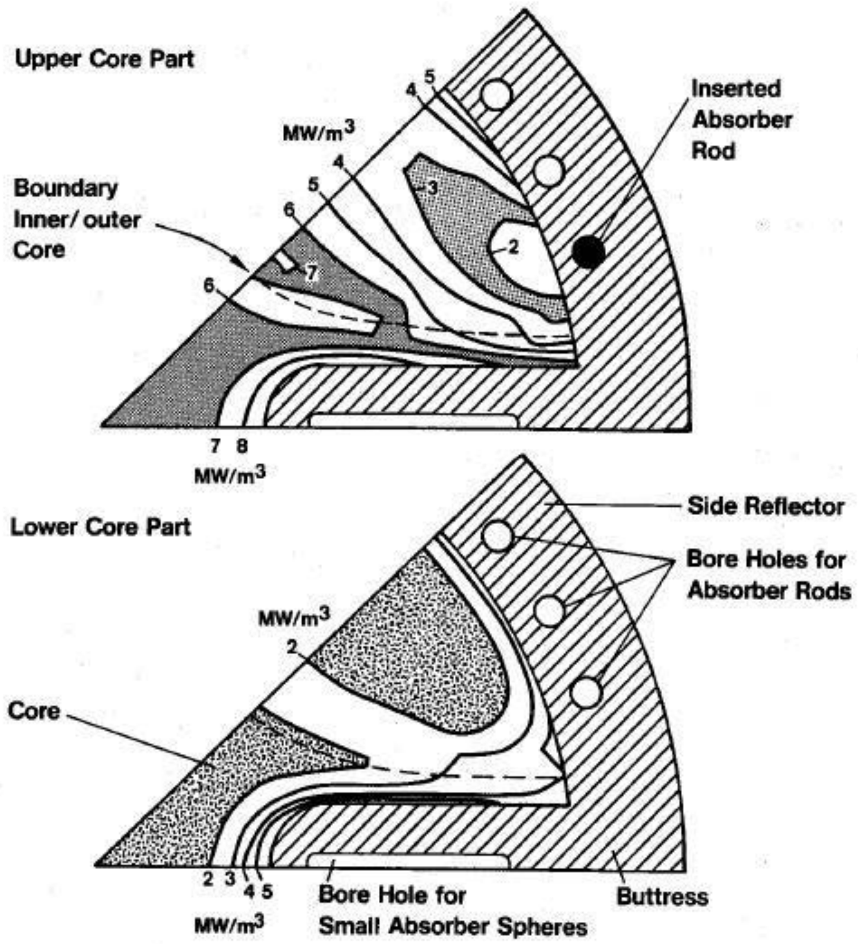

Figure 3.1-1: Lateral Power Distribution in the Reactor Core

The initial core consists of fuel elements, graphite elements, and in addition absorber elements. The core fuel elements contain 8 g of uranium at 6 % U-235 enrichment, the absorber elements contain 1.4 g of hafnium and 13.3 mg of boron.

The absorber elements are identical in particle size and matrix diameter to those of the THTR. The number of particles per absorber element is, however, only one third. As the equilibrium core the initial core is composed of an axially homogeneous inner and outer zone. The absorber elements are evenly distributed over the core cross section, whereas the fuel elements are distributed so as to result in a

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uranium density ratio of 1.25 between outer and the inner core zone. Table 3.1-2 shows a summary of further initial core data.

The temperature coefficient of reactivity, a factor of great importance to the dynamic plant behaviour, is negative under all operating conditions. In the equilibrium core, at steady-state full power operation, the temperature coefficient is about 5 x 10^{-5}/K.

The reactivity balance have a positive reserve for scram and long-term shut down. Table 3.1-3 shows a summary of the characteristic data. In the most frequent event, i.e., a reactor scram from normal operation without reactivity accident, the equilibrium core is subcritical by 0.4 % k even after a cool down to ambient temperature (300 K).

Table 3.1-1: Equilibrium Core Data

Maximum burn-up (heavy metal)	GWe/t	114.4
Max./mean burn-up ratio		1.15
Thermal power per fuel element:	maximum kW	4.4
	mean kW	1.46
Conversion rate		0.40
Maximum fuel temperature (rated power)	°C	1 084
Total fuel content:		
Heavy metal	kg	2 363
Fissile material U-235	kg	91
Pu-239	kg	10
Pu-241	kg	3

Table 3.1-2: Initial Core Data

		Inner Zone	Outer Zone	Total Core
Number of fuel elements		50 050	92 850	142 900
Number of graphite elements		70 000	85 300	155 300
Number of absorber elements		7 770	11 530	19 300
Total number of spherical elements		127 820	189 680	317 500
Mass of U-235	kg	24.0	44.6	68.6
Mass of U-238	kg	376.4	698.4	1 074.6

Table 3.1-3: Reactivity Characteristics (Equlibrium Core)

Control rod effectiveness (8 rods)	**%. k/K**	**% k/K**
Rod worth		4.3
Demand: 100-50-100 % Load cycle	2.9	
Reserve, Uncertainty	0.5	
Total demand		3.4
Long term shut-down system (SAS) effectiveness		
Worth		15.4
Demand: Temperature defect (to 300 K)	3.0	
Xe-135 decay	4.5	
Pu-239 build-up	0.2	
Uncertainty	0.8	
Min. shutdown margin	0.5	
Total demand		9.0
Total shut-down margin		6.4

3.2 Spherical elements

There are three types of spherical elements used in the reactor core: Fuel elements and graphite elements for the initial core, in addition, after the burn-in phase, absorber elements are used. Characteristic properties of the elements are:

- The uranium content and the carbon content of the fuel elements as well as the absorber content of the absorber elements permit normal power operation without any restrictions (reactivity requirement).
- Strength (surface wear, fracture of spheres) and dimensional stability (fabrication tolerances, neutron-induced shrinkage) of the fuel elements, graphite elements and absorber elements ensure their unrestricted handling during recirculation, discharge, and disposal. The influence of corrosion on the strength of the spheres has been taken into account.
- The fission product retention barriers of the fuel elements are designed so that access to the main circulator is not impaired by activity plate-out, and that the exposure of the environment during normal operation and depressurization accidents remains far below the limits permissible in the Federal Republic of Germany.

- The volatility of the absorber material from the absorber elements is very low so that a contribution to the reactivity balance is negligible even under accident conditions.
- Taking into account fabrication-induced damage, the portion of damaged coated fuel particles after burn-up will not exceed 5 x 10^{-4}.
- Damage of spheres by the fuel circulating system will remain below one out of 10 000.

Structure, design and fabrication of the fuel elements (Table 3.2-1) follow closely the THTR elements. Since the fission product spectrum of the LEU-cycle (Pu-fissions) contains a higher fraction of the extremely mobile silver atoms, the fuel particles are coated with an intermediate silicon carbide layer, in addition to the pyrocarbon coatings (TRISO-particles). This ensures an extremely low fission product release under all operating conditions. In the absorber zone of the absorber elements hafnium carbide is evenly distributed in the graphite matrix material. In addition, the absorber elements contain boron carbide particles. The application of the absorber-free shell corresponds to the procedure of fuel element fabrication. The graphite elements are machined as solid spheres from nuclear quality graphite.

Table 3.2-1: Fuel Element Data

Fuel Element		
Outer diameter	60	mm
Fuel zone diameter	50	mm
Relative uranium contamination of fuel elements	3 x 10^{-5}	
SiC Coated Fuel Particle		
Fuel material	UO_2	
Kernel diameter	500	µm
Porous layer	95	µm
Inner pyrocarbon coating	40	µm
Silicon carbide coating	35	µm
Outer PyC-coating	35	µm
Relative uranium contamination of the outer PyC-coating	1 x 10^{-6}	
Porition particies damaged during fabrication	3 x10^{-5}	

3.3 Shutdown Facilities

3.3.1 Absorber Rod System

The absorber rods (Figure 3.3.1-1) move in vertical bores in the side reflector. Each of the 24 absorber rods is composed of several sections connected by link joints to compensate possible displacement between reactor vessel and side reflector as a result of different temperature expansions. Each rod section consists of two coaxial tubes of austenitic steel which enclose the absorber material in form of sintered boron carbide rings (B_4C).

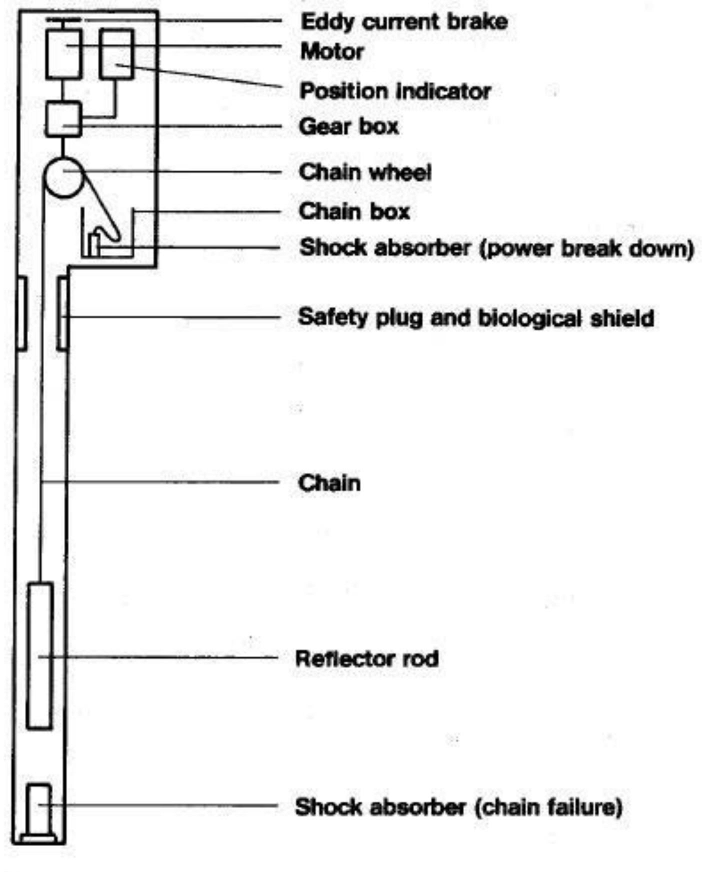

Figure 3.3.1-1: Reflector Rod

The absorber rods experience thermal stresses due to heat radiating from the core and the side reflector, respectively, and from heat produced in the B_4C-rings as a result of neutron absorption. To cool the absorber rods, a cold gas bypass flow is directed through the absorber rod bores. On its way the gas enters the rod through slits at the rod head and leaves it at the lower end through a central opening.

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The rod head contains the connection for the drive chain. A shock absorber at the bottom of each absorber rod bore absorbs the kinetic energy in the event of an uncontrolled drop of the reflector rod (e.g. chain rupture), so that undue damage of the rod or the channel is avoided.

Each absorber rod is suspended by a link chain and driven by a three phase asynchronous motor via reducing gears and a sprocket wheel. In case of rapid rod insertion e.g. a reactor scram (with the motor de-energized) the rod speed is limited by an eddy current brake. A scram shock absorber at the loose end of the chain stops the end of its stroke. A shielding plug below the motor drive shields the drive against neutron radiation from the core. The entire unit can be removed for service (Table 3.3.1-1).

Table 3.3.1-1: Absorber Rod System Data

Pitch radius	m	1.87
Stroke	m	8
Rod diameter (cladding tube/joints)	mm	85/95
Drive three phase asynchronous motor		
Temperature of drive casing	°C	90
Link chain temperature range	°C	60-300
Coolant gas inlet temperature at the absorber rod	°C	260
B_4C-rings	°C	720
Cladding tubes	°C	580

3.4 Small Absorber Sphere Shutdown System

The SAS is used for long term shut-down of the reactor. For shut-down small absorber spheres of 9.5 mm diameter are released from 4 storage vessels and fall through feed tubes into the long channels provided in the reflector buttresses. The total capacity is about 2.4 x 10^6 spheres of borated graphite. The storage vessels are arranged outside the reactor pressure vessel and are equipped with two independent mechanisms, a level meter, and a separator.

For reactor re-start the SAS are withdrawn by gravity from the channels, run through a withdrawal and feeder device, and are conveyed pneumatically back into the storage vessel (Figure 3.4-1).

The SAS release mechanism inside the storage vessel is of redundant and diverse design, consisting of a valve-like play and movable ring with separate actuators, one active and one fail-safe.

The withdrawal/feeder device located below the core is triggered pneumatically by external valves. For reactor operation modes with low differential pressure of the core an auxiliary return blower is foreseen.

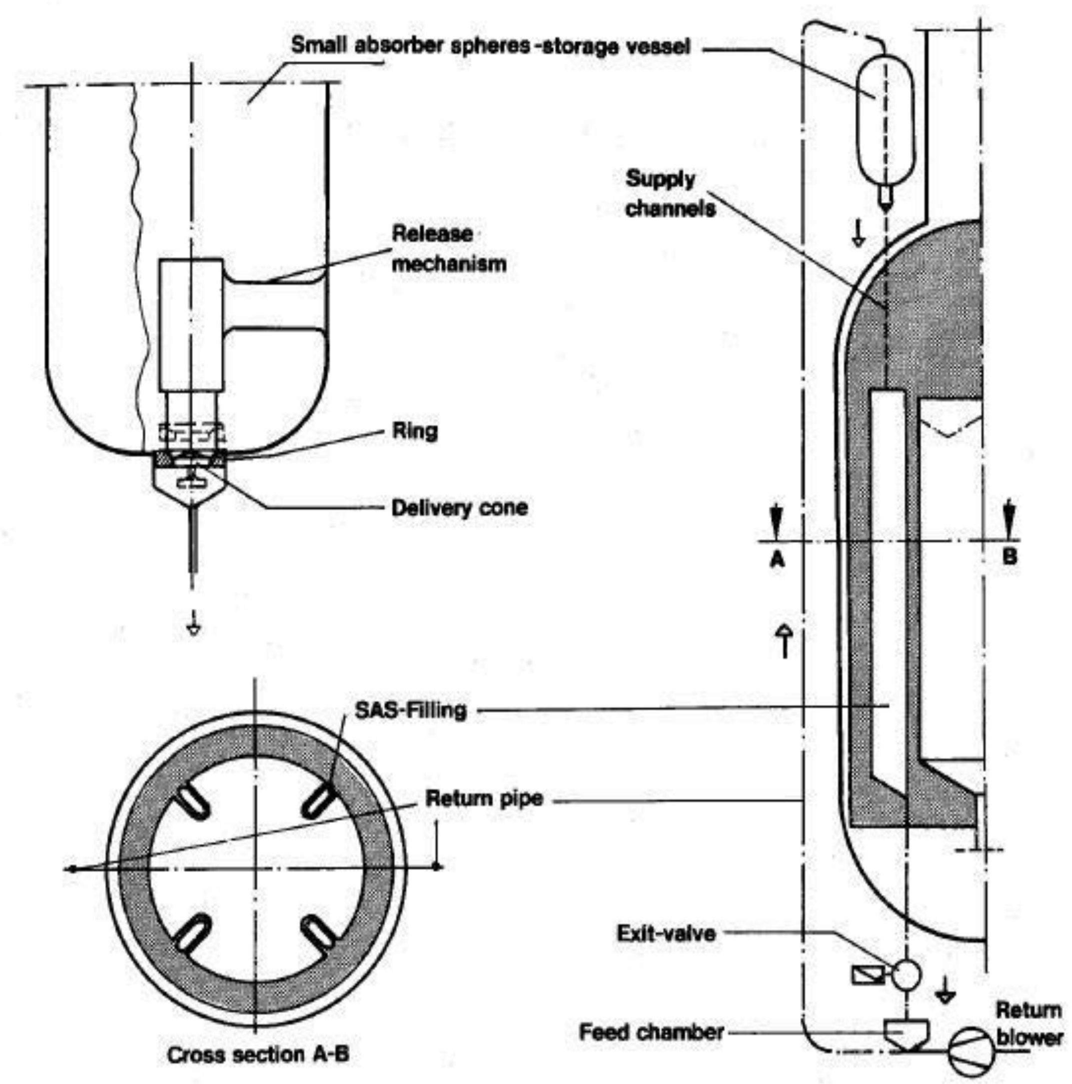

Figure 3.4-1: Small Absorber Spheres Shutdown System

4 Reactor Cooling System

The reactor coolant circuit transfers the heat generated in the core to the steam generator, both within the reactor pressure vessel, via helium as the coolant (Figure 4-1). The helium inventory of the reactor is kept constant during operation. The helium is continuously purified by the helium purification system which is arranged in a bypass.

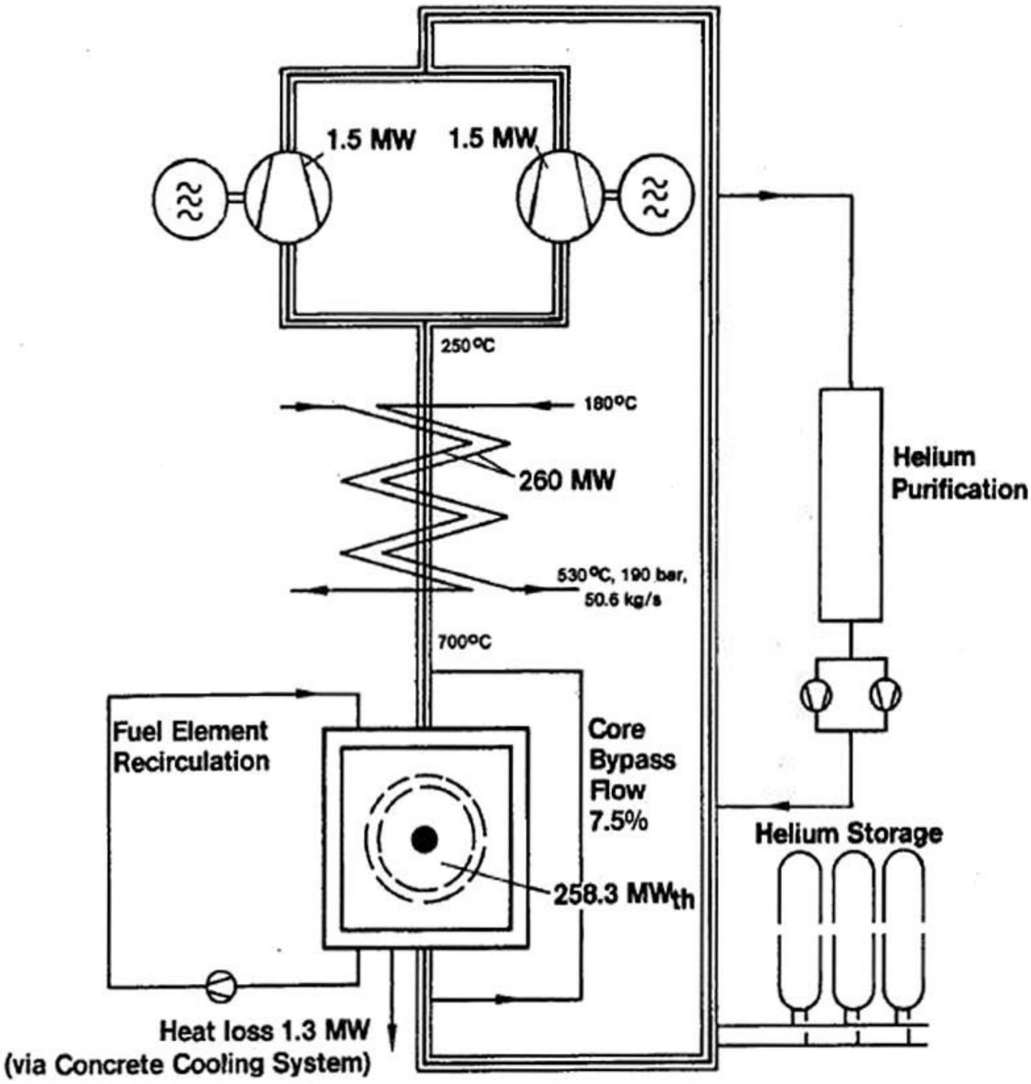

Figure 4-1: Reactor Coolant System

The gas is circulated by two helium circulators mounted above the steam generator. The plant can be operated with only one circulator at part load (50 %) and at reduced mass flow in both the primary and the secondary circuit.

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During normal operation the two circulators blow the helium through the annular clearance between the pressure vessel wall and steam generator or core, respectively, at a pressure of 7.0 MPa and a temperature of 255 °C. On its way down the helium temperature increases somewhat by heat transferred from the steam generator shroud and the side reflector.

In the lower part of the reactor pressure vessel the gas flow is reversed, entering the bottom reflector of the reactor from below. Appropriate baffles ensure a uniform distribution of the coolant flow entering the pebble bed through openings in the bottom reflector. The gas reaches the void above the pebble bed at about 740 °C. Two bypass flows, one through the absorber rod bores in the side reflector, one through the SAS channels in the buttresses, merge with the main flow partly within the void above the pebble bed, partly within the slotted channels in the top reflector. The temperature of this mixed gas flow at the steam generator inlet is 700 °C.

During power operation the heat generated in the reactor core is transferred to two independent steam/feedwater circuits of the steam generator. The tube bundles are wound into each other. The steam/feedwater flow is downward while the helium flow is upward with a temperature at the steam generator outlet/circulator inlet of 250 °C.

To reduce temperature cycles of the pressure vessel, a cold gas temperature control was chosen.

During shut-down of the reactor and under all accident conditions the gas flow direction remains unchanged. For decay heat removal the gas flow rate is reduced accordingly, and possibly only one circulator is used, whose speed is controlled according to the required gas flow. During a failure temporary rise in temperature and pressure occurs in individual regions. This is taken into account by a cold gas temperature design value of 325 °C at a pressure of 7.7 MPa.

4.1 Reactor Pressure Vessel

The reactor pressure vessel is the pressure containment of the entirely integrated primary system: reactor core, steam generator, and circulators. The vessel consists of an upper and a lower section, joined by a flange. The reactor core is located in the lower part of the vessel, the steam generator in the upper, and the circulators in the two bolted-on housings on top of the vessel.

Main design characteristics are:

- Use of the proven reactor pressure vessel material 20 MnMoNi 55
- Possibility of shop fabrication or on-site assembly
- Transport by sea, individual sub-assemblies also by road
- In-service inspectability of all welds and high stress areas
- By appropriate layout of the primary circuit the vessel inner wall is exposed to "cold" helium only.

The principal design data are compiled in Table 4.1-1.

Table 4.1-1: Pressure Vessel Main Data

Upper Section		
Height	m	12.1
Diameter at steam generator	m	3.0
Diameter at the dome	m	4.6
Lower Section		
Height	m	17.7
Diameter (outside)	m	6.1
Wall thickness	mm	140
Total height	m	30
Design pressure	MPa	7.7
Total weight (without internals), approx.	kg	750 000
Design life	a	40

The reactor pressure vessel is made from seamless forged cylinders, a forged cone, and hot formed top and bottom heads. The dimensions of the forgings are large so that only few circumferential welds are required. There are no longitudinal weld seams.

The "appendix" to the bottom head houses the fuel element discharge device with the scrap separator. Further connections are for the SAS recirculation system, for instrumentation, and for inspection.

The lowest ring of the cylindrical wall is reinforced to accommodate the star-shaped core support structure. The top ring of the lower vessel section has a forged-on collar for support of the entire pressure vessel. The forged-on collar simultaneously serves as the lower part of the flange for the top section.

The upper part of the flange is formed by the conical transition piece to the smaller diameter upper section of the vessel. This cone contains the penetrations for the absorber rods, the start-up neutron source, and the small absorber spheres. The top most part of the vessel has an enlarged diameter to provide space for the steam and feedwater headers and for the circulator housings. The live steam and feedwater headers are connected to the vessel via thermo sleeves and (where applicable) by bimetallic welds. All the welds are accessible for in-service inspection.

The top head of the vessel carries the two circulator housings. The housings themselves are equipped with flanged heads, permitting access to the circulators for maintenance, circulator removal, and access to the steam generator in the area of the steam and feed water heaters.

The design of the pressure vessel permits pressure testing either in the shop or in situ after installation. For assembly of the main flange and all other major flange connections a stud tensioner will be used to ensure uniform tensioning.

4.2 Ceramic Internals

The core cavity is formed by the ceramic internals: The bottom reflector, the side reflector, and the top reflector (Table 4.2-1 and Figure 4.2-1). These graphite components transfer the forces from weight and spheres pressure as well as seismic loads to the adjacent metallic internals.

The rigidity requirements of the graphite structure are not very strict, since jamming of fuel elements cannot occur in the pebble bed core, the flowing of spheres is ensured even in case of irregularities in the reflector structure.

The entire ceramic structure is built up of individual graphite blocks. It rests on the bottom thermal shield. Radially, it is supported by the side thermal shield via metal guides which fit into corresponding grooves in the blocks, thus preventing azimuthal shift of the graphite structure. All differential expansions occurring between the ceramic blocks are compensated within the structure by expansion gaps.

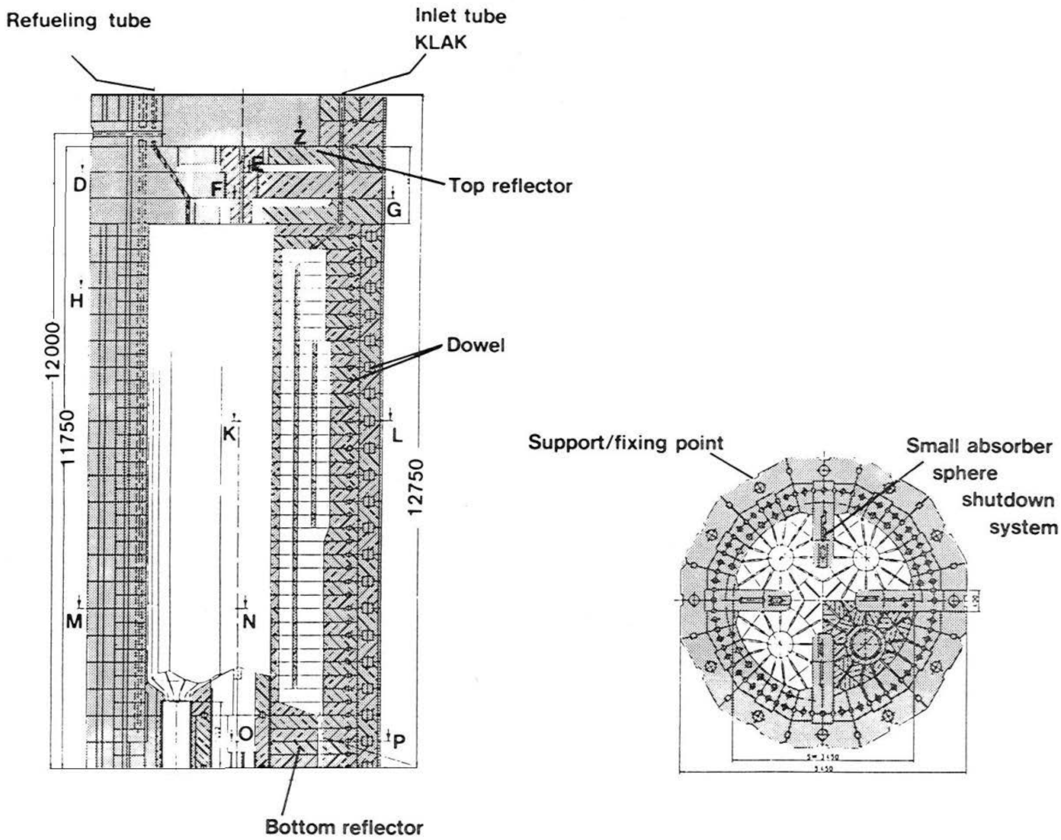
The side reflector is formed by an inner and an outer cylindrical layer consisting each of reflector blocks piled up to columns. The blocks are vertically fixed by dowels and horizontally by keys. The keys simultaneously serve as seals, limiting the bypass flow through the vertical gaps between the columns. The two cylindrical layers interlock to prevent shifting. The inner layer has 24 vertical bores for the absorber rods.

Four buttress-like columns 90° apart protrude from the inner wall of the side reflector into the pebble bed. These buttresses have each a long vertical channel for the small absorber spheres.

In the lower core region the core side surfaces of the side reflector blocks and the buttresses have irregular pits to prevent a regular pebble pattern which would hamper the flow of the spheres. Above the pits the side reflector blocks and buttresses are slotted to limit the stresses induced by neutron radiation and high temperatures.

The bottom reflector carrying the weight of the core and the side reflector, consists of trapezoidal graphite blocks. The four buttresses sub-divide the bottom reflector into four segments with funnel-shaped inlets for withdrawal of the spheres. The four funnels and related discharge tubes ensure an even flow of spheres from the pebble bed.

The top reflector consists of three layers of cantilevered segment shaped graphite blocks and a central plug. The cantilevers rest on the inner layer of the side reflector and are held in position by dowels and keys. A grid of gas channels is provided in the top reflector to thoroughly mix the main gas flow and various bypass flows for homogeneous temperature distribution at the steam generator inlet. Further channels are for the addition of fuel spheres and the small absorber spheres.



Side view Top view

Figure 4.2-1: Ceramic Internals

Three types of graphite are used for the structure depending on the particular requirements:

- Isotropic reflector graphite of high strength characteristics and resistant to high neutron fluxes. The material is used especially in areas near the core.
- Normal reactor graphite of average strength which is used in the outer zones of the reflector structure.
- Low-ash carbon material used for thermal insulation and/or shielding.

Table 4.2-1: Ceramic Internals Data

Overall height of reflector	m	12.75
Outer diameter	m	5.45
Side reflector wall thickness	m	1.0
Top reflector thickness	m	1.50
Min. thickness of bottom reflector	m	1.25
Number of buttresses	m	4
Width of buttresses	m	0.45
Clearance between opposite buttresses	m	1.25
Number of top reflector layers		3
Number of fuel element discharge tubes		4
Bottom reflector funnel inclination	degrees	30
Pitch diameter of funnel centres	m	2.3

4.3 Metallic Internals

The metallic internals comprise thermal (neutron) shields, support structures, and special internals. They have various functions, such as support of the core structure, radiation shielding, coolant gas baffling, separation of cold and hot gas regions, and they form part of the re-fueling system.

The central part of the metal internals is the star shaped core support structure (Figure 4.3-1). It rests on twelve support arms which transfer the loads to the reactor pressure vessel via roller bearings, taking up thermal expansion but preventing rotation. The bottom plate, mounted on top of the star support, carries the ceramic core structure. Slots in the bottom plate permit passage of the coolant gas.

The four fuel element discharge tubes are mounted on the support at a pitch diameter of 2.3 m and offset by 45° to the graphite buttresses. The tubes have a diameter of 0.5 m and reach into the bottom reflector by about 1.25 m. The tubes are welded to a header below the star support which collects the withdrawn spherical elements. Below this header the withdrawal equipment is located. Likewise, the withdrawal device for the small absorber spheres is arranged below the star support.

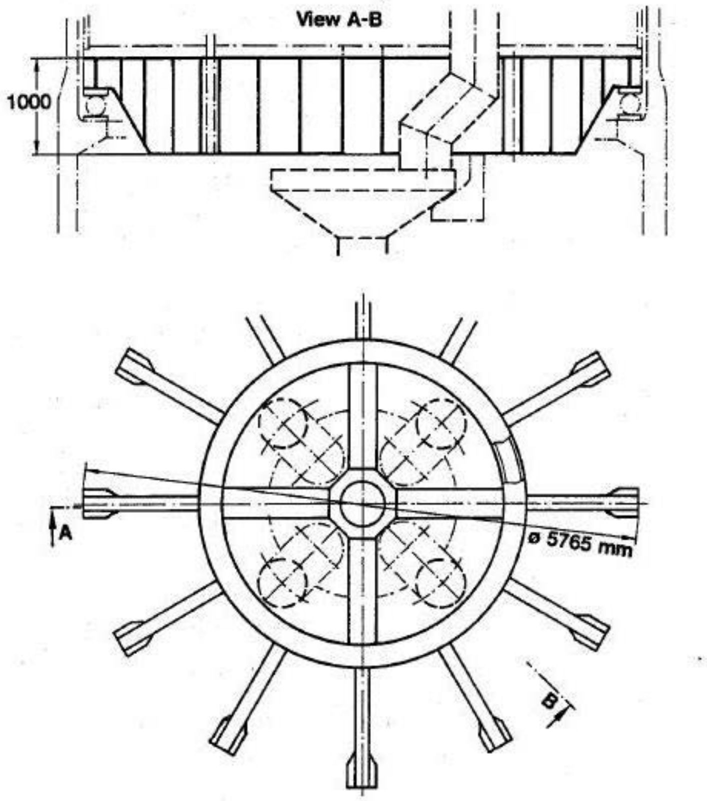


Figure 4.3-1: Core Support Structure

The side thermal shield is mounted on the rim of the bottom plate. It holds the side reflector as described in Section 4.2. There is an annular gap between the side thermal shield and the reactor pressure vessel wall for the cold gas flow.

The top reflector is sealed by a cover plate which is connected to the side shield. Sliding seal sleeves penetrating the cover plate are provided for the absorber rods. A steel shroud with inside insulation is mounted centrally on top of the cover plate. On its upper end it has a sliding seal connection to the steam generator, separating the hot and cold gas streams.

The re-fueling tubes enter the reactor pressure vessel at the annular flange and pass through the upper region of the pressure vessel at a 10° slope. At their penetrations through the top reflector they are fixed to the cover plate. The design temperatures of the metallic internals are 350 °C for normal operation and 450 °C for accident conditions.

4.4 Circulator

Two vertical shaft circulators are installed above the steam generator dome in separate pressure vessels. The circulators are single-stage radial blowers driven by a variable speed asynchronous motor. They are a follow-on design of the circula-

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tors operating in the THTR 300 nuclear power plant, but with active magnetic bearings instead of oil lubrication. Magnetic bearings are already in use in heavy rotating machinery, especially machine tools.

A circulator unit consists of the circulator shaft with impeller, the active magnetic bearings and catcher bearings, the electric motor, the flow restrictor plate, gas ducts, shutoff valve, coolers, and electronic equipment for the active magnetic bearings. All these parts except electronics form a single unit which is integrated into the primary coolant system. The dimensions are shown in Figure 4.4-1, the technical data are listed in Table 4.4-1.

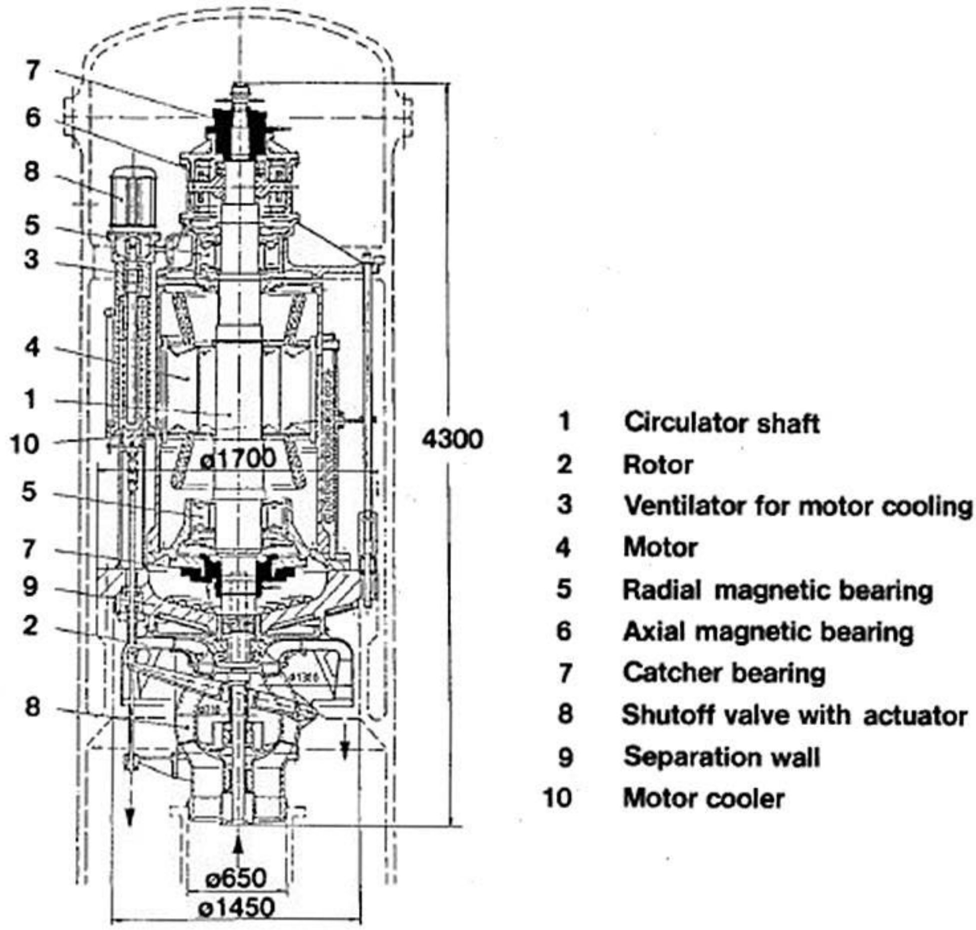


Figure 4.4-1: Helium Circulator

The circulator shaft is held on both sides of the motor by radial magnetic bearings and at its upper end by an axial magnetic bearing. The magnetic bearings have no contact with the shaft. The radial bearing consists of a rotor of ferromagnetic sheets shrunk to the circulator shaft, and an external stator with the electromagnets. The magnets generate a field which holds the rotor freely suspended. The magnetic field and therefore the rotor position is continuously controlled by the electronic control system.

Table 4.4-1: Circulator Data

General		
Number of circulators	2	
Fluid	Helium	
Normal operation (100 % load)		
Suction pressure	MPa	6.87
Suction temperature	°C	250
Mass flow	kg/s	55.6
Static pressure rise	kPa	137
Electric power demand	kW	1500
Speed	min^{-1}	5450
Load range	%	15-103
Decay heat removal operation (Reactor pressurized)		
Suction pressure	MPa	7.0
Suction temperature	°C	250
Mass flow	kg/s	5.54
Static pressure rise	kPa	16
Dimensions and weight		
Max. diameter	m	1.6
Max. length	m	4.2
Weight	kg	12000

The axial bearing is based on the same principle as the radial bearing, but with a disc rotor and circulator stator magnets on both sides. In addition, mechanical catcher bearings are provided above and below the magnetic bearings, acting in radial, and in radial-axial direction, respectively. The catcher bearings are non-lubricated roller bearings. During normal operation they are not in contact. With the magnetic bearings shut down or in case of failure the circulator shaft drops into the mechanical catcher bearings by about 0.5 mm, ensuring safe coast-down of the circulator.

The motor section is sealed against the primary gas side by a labyrinth seal at the circulator shaft penetration of the flow restrictor plate.

A shutoff valve is provided at the circulator intake to prevent reverse gas flow during single circulator operation. The shutoff valve is driven by an electric actuator.

The motor section is cooled by helium which is circulated by an auxiliary ventilator mounted on the circulator shaft. A helium/water cooler within the motor section transfers the heat to a cooling water circuit. In addition, the flow restrictor plate is cooled by welded-on cooling water tubes.

The circulator is driven by a two-pole three-phase squirrel cage motor with variable frequency control. Motor casing stator and circulator casing form a rigid unit supported by the flow restrictor plate. The insulation and the magnetic bearings are designed for temperatures up to 155 °C, they are voltage-resistant to radiation.

The electronic control system is located outside the reactor cavity. It is redundant so that repair work can be performed without shutting down the circulators. Standby power is supplied by battery.

4.5 Steam Generator

The steam generator transfers the heat generated in the core to the secondary circuit, during normal operation of the plant and also for decay heat removal. On the steam/water side it is divided into two systems.

The steam generator is located above the core in the upper part of the reactor pressure vessel. The heat exchanger consists of two separate systems of tubes wound into a single unit of concentric helicoils (Figure 4.5-1). Gas flow is from the hot gas plenum above the top reflector in a single pass upward through the tube bundle to both circulators. On the water side flow is downward with downflow evaporation.

The design follows the THTR 300 and the HTR 500 steam generator designs to a large extent. Accordingly, the heat exchanger tubes are helically wound and held in vertical support plates by wedged sleeves for protection against fretting. The helices form cylindrical layers, the tubes being alternately connected to their pertinent system. Feedwater and live steam headers are of the tube sheet type. The entire unit is surrounded by the steam generator shroud which also carries the load of the tube support plates.

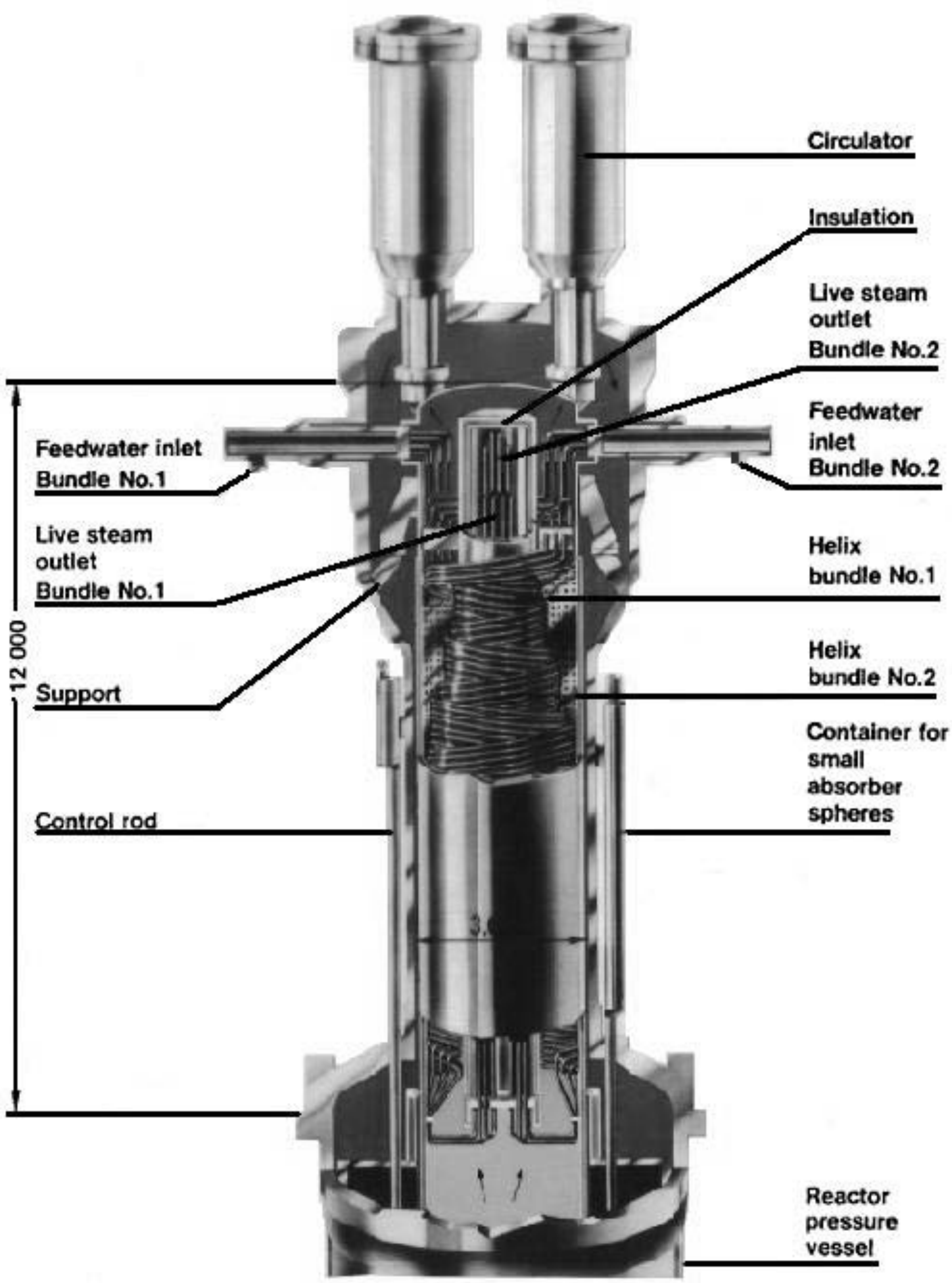


Figure 4.5-1: Steam Generator

The feedwater tubes run from the two headers on opposite sides above the steam generators to the tube bundle, with bends to compensate thermal expansion. Live steam tubes return from the bottom of the bundle through a central duct to the two live steam headers 90° opposed to the feedwater headers. The returning live steam tubes are separated from the hot gas by a seal plate at the bottom entrance of the center duct.

Suitable materials are: For the feed water headers 20 MnMoNi55, for the heat exchanger tubing and the main steam headers Incoloy 800. The materials may, however, change as optimization progresses.

The main technical data of the steam generator are summarized in Table 4.5-1.

Table 4.5-1: Steam Generator Data

Thermal power	MW	260
Load range	%	100 - 50
Number of tube systems	-	2
Gas inlet temperature	°C	700
Gas outlet temperature	°C	250
Gas mass flow	kg/s	111.2
Gas side pressure	MPa	7.0
Feedwater temperature	°C	180
Live steam temperature	°C	530
Live steam pressure	MPa	19.0
Steam mass flow (per system)	kg/s	50.6
Tube diameter	mm	20
Number of tubes (total)	-	322
Tube bundle height	m	10.23
Diameter of outer bundle	m	2.74

5 Reactor Service System

5.1 Helium Purification System

The helium systems are required for helium purification and storage, for gas analysis, for evacuation of reactor systems, purging and re-pressurization with purified helium. The systems are not safety related.

The helium purification system removes continuously the graphite dust and the chemical impurities H_2, H_2O, CO and CO_2 from the primary circuit in a bypass taken from the primary coolant circulator discharge. A schematic diagram of the helium purification system is shown in Figure 5.1-1 the main data are compiled in Table 5.1-1.

The bypass flow first passes through a dust filter system. As in the AVR, this can be a gravel bed filter with grain sizes of 0.8 to 4 mm and subsequent aerosol filter with 99.95 % separation. The helium then passes through an oxidizing bed where the hydrogen is oxidized into water and the carbon monoxide, into carbon dioxide. The temperature of the purification flow is then reduced to about 10 °C in two coolers, the first being cooled by an intermediate cooling circuit and the second, by the cold water system.

Each cooler is followed by a condensate trap. The cooled helium flows through a molecular adsorber for separation of water and carbon dioxide. Two adsorbers are provided in parallel for alternate regeneration. From the adsorber the helium is returned to the primary circuit by one of two parallel compressors or, alternatively to the helium storage. The molecular adsorber is regenerated via an electric heater and a circulation pump. The discharge line to the stack is equipped with a cooler and condensate trap. The amount of impurities in the helium is measured using the gas analysis system.

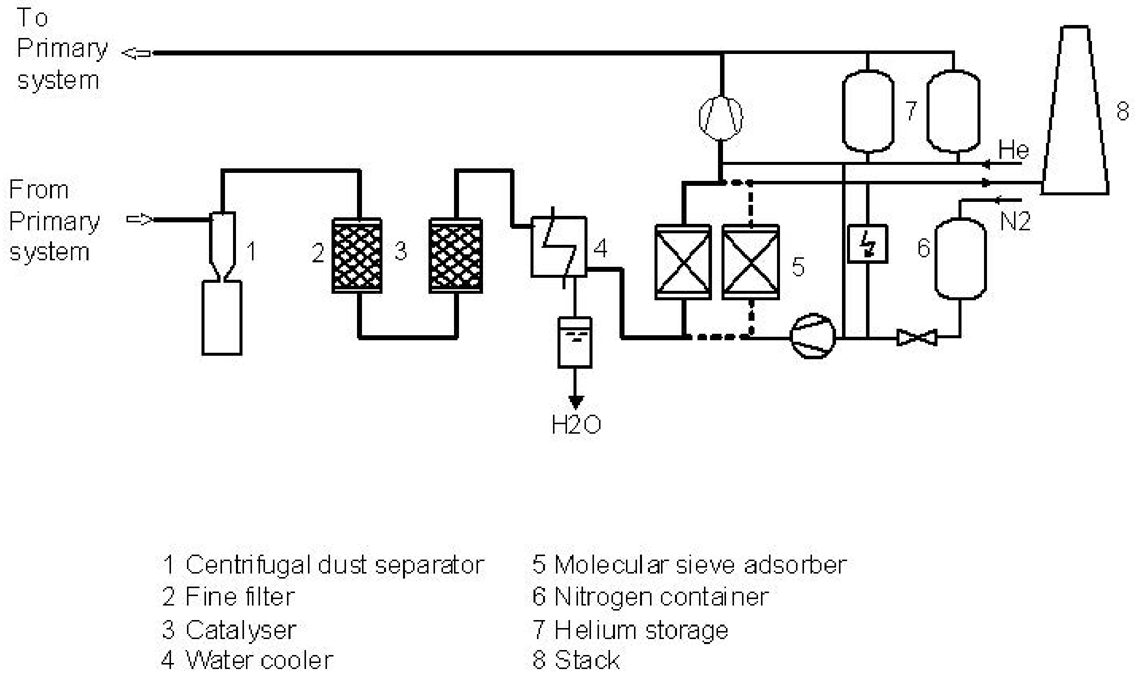


Figure 5.1-1: Scheme of Helium Purification System

In order to depressurize, purge, and re-pressurize the inlet and outlet locks of the fuel circulating system depressurization, purging, and vacuum systems are provided. They are also used to purge system sections prior to maintenance work.

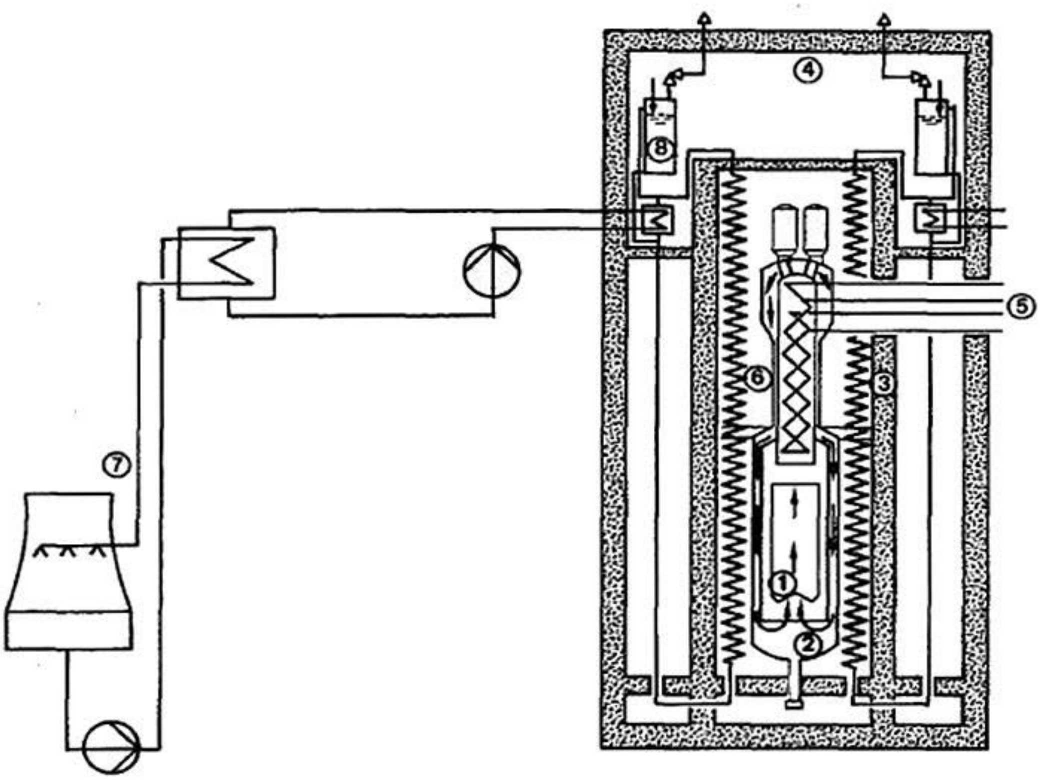
The helium storage system is used for storage of purified helium from the primary circuit during maintenance, for storage of high purity helium for make-up to the primary circuit, and for flushing.

Table 5.1-1: Helium Purification System Main Data

Primary Circuit Inventory (approx.)	kg	3800
Bypass through He Purification System	kg/h	130
Impurity Limits (Partial Pressures)		
H_2	Pa	50
CO	Pa	50

5.2 Concrete Cooling System

The biological shield surrounding the reactor pressure vessel is equipped on its inside with a surface cooler. During normal plant operation this cooler removes the heat transferred by convection and radiation from the reactor vessel and keeps the concrete temperature of the biological shield within allowable limits. The schematic flow diagram of the entire concrete cooling system is shown in Figure 5.2-1.



1 Reactor Core
2 Reactor Pressure Vessel
3 Biological Shield
4 Reactor Building
5 Main Heat Sink
6 Concrete Cooling System
7 Cooling Water
8 Storage Tank

Figure 5.2-1: Concrete Cooling System

In the rare event that the normal heat path (by way of the steam/water system) is not available for decay heat removal the concrete cooling system acts as the stand-by heat removal system, removing the decay heat dissipated through the reactor pressure vessel wall. The system has two loops. Each loop is capable of removing 50 % of the heat generated in the worst case. The main components are the two-loop surface cooler, the storage tanks, the intermediate coolers, the connecting piping, and instrumentation. The concrete cooling system loops function by natural convection.

Heat from the intermediate coolers is normally removed by the primary cooling water system, a closed cooling water loop also serving other primary components. The heat sink for the primary cooling water system is foreseen to be sea water. Alternatively, fresh water cooling or forced draft cooling towers may be used. The two-loop surface cooler consists of vertical cooling tubes welded together via strips, thus forming the closed inner wall of the biological shield.

The tubes are alternatively connected to the headers of the respective loop. Each tube in accessible for in-service inspection. Ancillary system to the concrete cooling system provide condensate for make-up, water conditioning chemicals, and nitrogen for blanketing.

If the cooling water chain of the concrete cooling system is interrupted, e.g. due to external events such as extreme earthquake or man-induced events decay heat is still removed by evaporation of water from the storage tanks. In this mode of operation the concrete cooling system functions in a completely fail-safe way requiring no active components such as pumps or valves, and no power supply. The storage tanks have sufficient evaporative capacity. Provisions are, however, made to add cooling water from external sources. Each tank is blanketed with nitrogen for corrosion protection.

5.3 Fuel Handling Facilities

The fuel handling facilities include the storage for new fuel elements, the fuel circulating system, and the spent fuel storage. Within the fuel circulating system new fuel, graphite, or absorber elements are added to the core, used elements are withdrawn, and elements not yet completely spent are re-circulated.

The circulating system operates at atmospheric and at primary circuit pressure. It therefore contains a number of special valves ("locks") to sluice the elements from atmospheric to primary circuit pressure and back. Several valves are combined into a so called valve block. Other main components of the fuel handling facilities are the loading station, the withdrawal device with spheres singulizer and scrap separator, the pneumatic conveying system, the burn-up measuring device, and the fuel discharge station. In addition, storage for new and for spent fuel is provided. Figure 5.3-1 shows the schematic diagram of the fuel circulating system, Table 5.3-1 the main data.

The fuel elements arrive packed in 2001 standard steel drums with boron lining (1000 fuel elements per drum, as for the THTR). The drums are stored on shelves in the fresh fuel storage and later on transported to the loading station by a fork lift.

In the fuel element loading station and loading block the spheres are separated and sluiced-up to 7 MPa primary pressure. During the loading procedure the section between locks is evacuated and purged with helium to prevent ingress of air into the primary system.

From the lock section elements are introduced into the fuel circulating system upstream of the burn-up measuring device. Thus, in the collecting block, the spherical elements withdrawn from the core join the fresh elements and pass individually

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through the burn-up measuring device. Depending on its state of burn-up the fuel element is discharged or, re-circulated into the core to the central or a peripheral position, depending on the position of the switch in the distributor block. Fuel elements to be discharged are collected in the discharge lock section and are then (similar to the loading procedure) sluiced out of the helium system. Elements to be re-circulated are conveyed pneumatically up to the distributing station.

The spherical elements for the inner core are added directly whereas the elements for the outer core are distributed by a multiple switch to the desired peripheral position. After having passed the reactor core and the discharge tubes the elements are collected in the headers and enter the singulizer/scrap separator unit. Here the spherical elements are individually withdrawn. The intact elements are re-circulated, the damaged spheres discarded into the scrap container.

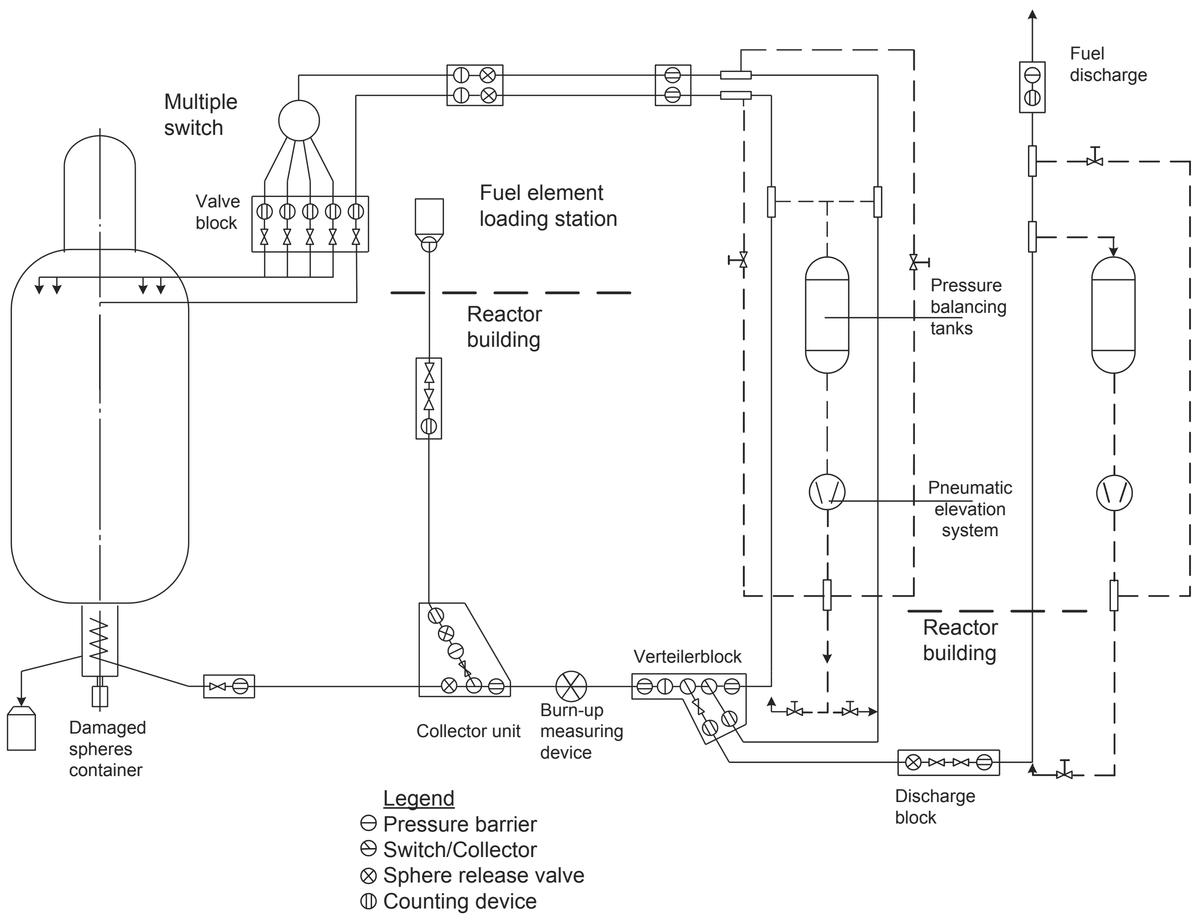

Figure 5.3-1: Fuel Circulating System

Burnt-up fuel elements sluiced out of the system are transported to the spent fuel storage by a separate pneumatic conveying system operating with air at atmospheric pressure. The spent fuel element storage is located in a separate building adjacent to the reactor auxiliary building. The storage contains all systems and components required for storage and handling of spent fuel elements. It has a capacity for about 10 years of operation. The decay heat generated in the spent fuel elements is removed by cooling the storage. Appropriate shielding is provided against radiation.

The fuel circulating system is similar to the one of the THTR. In fact, many components are proven in the THTR, such as the double seat valves, switches, dosing devices, pressure locks, valve blocks, and spheres counting devices.

Table 5.3-1: Fuel Circulating System Data

Re-fueling	180 Fuel elements/full power day
Discharge	180 Fuel elements/full power day
Circulation	2 000 Fuel elements/full power day

5.3.1 Radioactive Liquid Waste Handling

The liquid waste from the controlled access area and all radioactive liquid waste is collected in holding tanks, and treated separately, depending on chemical conditions and radioactivity. The treated liquid waste runs into the main waste water line. The liquid and solid concentrates are transported to concentrate solidification facilities outside the plant. The facility for decontamination of components is located in the reactor auxiliary building. It consists of a dismantling cell and a decontamination cell surrounded by concrete shielding walls.

The dismantling cell is equipped with a crane, a turn table, and two master-slave manipulators. Observation of the cell is possible through a shielding window. Direct access to the dismantling cell is possible through a shielding door. The decontamination cell is designed so as to permit decontamination of components from outside. The procedures in the cell can be observed through a shielding window. Access is through a shielding door.

Low-contaminated parts are decontaminated manually. In this case the operating personnel is positioned behind a steel wall equipped with glove box openings and a window. Two procedures are available for decontamination: The wet blast process and the jet cleaning process. With the wet blast process components are de-scaled, cleaned, and decontaminated by mechanical abrasion. The blasting fluid is water with 10 % of glass beads added. Abrasion is controlled by controlling the flow rate of air induced into the water jet. Depending on size and type, the components to be decontaminated are treated from an operating station outside the cell or, by a person working inside.

The jet cleaning process uses a high pressure jet (8 MPa) at an ejection rate of 1.5 m^3/hr and a water temperature of 60 °C. A water temperature up to 90 °C is possible at half rate. Two different chemicals can be added at variable concentration.

6 Power Plant Service Systems

6.1 Heating, Ventilation and Chilled Water Systems

6.1.1 Heating, Ventilation and Chilled Water System of Reactor Plant

The ventilation systems have no safety-engineering importance, with the exception of the subsystems listed below.

These exceptions are:

- The depressurization system in the reactor building
- The circulating air fans in the fuel element storage building
- Those ventilation systems in the switchgear building required for coping with accidents

The ventilation systems of the reactor plant supply the exclusion area of the reactor building, the reactor auxiliary building and the fuel element storage building.

For ventilation engineering purposes, the reactor building is divided into Unit A and Unit B. The rooms for the helium purification system are for both units in common, and house systems carrying primary coolant gas, whose depressurization cross-sectional area can reach 33 cm^2.

The common supply and exhaust air systems for the entire exclusion area and the demand filter systems are installed in the upper floor of the reactor auxiliary building (Figure 6.1.1-1 and Table 6.1.1-1).

Table 6.1.1-1: Design Data for Ventilation Equipment in the Exclusion Area

System component	Redundancy (%)	Air volume flow (m^3/h)
Demand filter system	3 x 33.33	3 x 5 000
Circulating air cooling system FE supply		8 x 3 000
Circulating air cooling system steam generators		8 x 10 000
Circulating air cooling system steam deck		4 x 6 000
Circulating air cooling system demand filter system	3 x 33.33	3 x 600
Circulating air cooling system FE store	2 x 50	2 x 15 000

System component	Redundancy (%)	Air volume flow (m³/h)
Circulating air system FE store	3 x 50	3 x 10 000
Common supply air system	2 x 50	2 x 60 000
Common exhaust air system	2 x 50	2 x 66 000
Depressurization equipment in un-disturbed operation	1 x 100	1 x 10 000

The design is based on room air temperatures between min. 20 °C and max. 35 °C. and for the FE store max. + 60 °C.

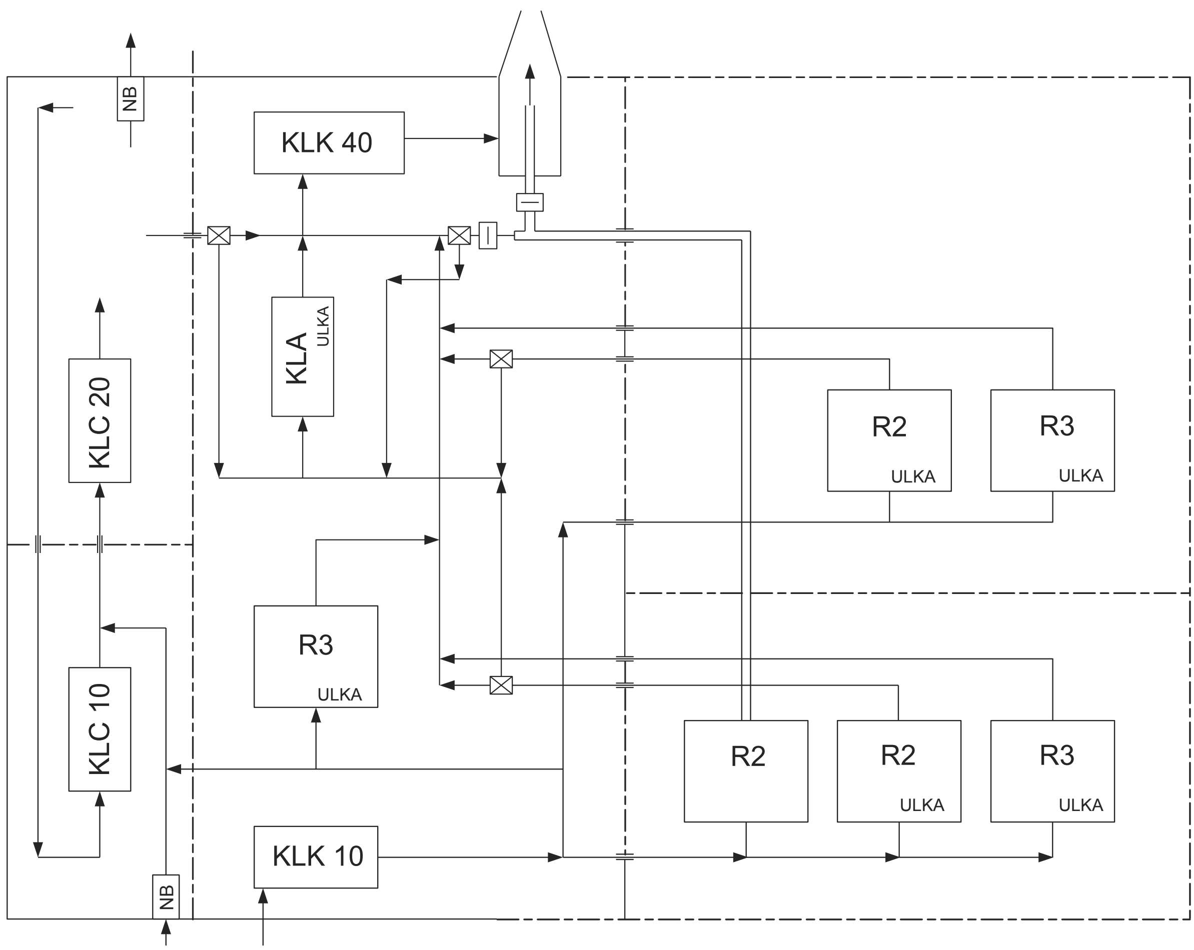

Figure 6.1.1-1: Exclusion Area Ventilation System Diagram

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Legend to Figure 6.1.1-1

NB	Emergency operation
R1, R2, R3	Area groups
ULKA	Re-circulated air refrigerating system
ULAN	Air recirculation system
KLK 10	Supply air system
KLK 40	Exhaust air system
KLK 80	Depressurization facility
KLC 10	Re-circulated air refrigerating system of fuel element storage building
KLC 20	Air recirculation system of fuel element storage building
KLA	Demand aerosol and iodine filter system

A circulating air system installed in the fuel element (FE) store and designed to withstand external events, provides sufficient ventilation, in conjunction with the common supply and exhaust air systems; the heat is removed by a circulating air cooling system. After an external-event accident, the FE cooling system can be run in stand-alone mode with purely outside-air operation.

The common supply and exhaust air systems, in conjunction with the circulating air systems, serve to maintain specified room climates in regard to temperature, humidity and fresh air, plus a group-graduated maintenance of sub atmospheric pressure, so as to ensure the desired accessibility conditions. The common exhaust air system also serves for monitored removal of operating leaks from the systems in the exclusion area carrying primary coolant gas to the surrounding atmosphere through the exhaust air stack; these leaks are considerably smaller than 0.1 % per day of the helium inventory. In addition, the common exhaust air system, in conjunction with the demand filter system, serves for monitored removal and retention of airborne radioactive substances.

Larger, accident-related primary coolant gas leaks possible in the R1 and R2 rooms are handled with the supply and exhaust air system up to 0.2 kg/s of helium, corresponding to a leak cross-sectional area of 1 cm^2. The helium leakage to be assumed as covering all primary coolant gas leaks in the R1 rooms (10 kg/s of helium, corresponding to a leak of 33 cm^2), results in triggering the depressurization system for channel interrupts the connection to the common exhaust air system, and the helium pressure is directly reduced as the gas escapes via a concrete channel and the exhaust air stack into the atmosphere. Check valves ensure that the remaining plant rooms are protected from the pressure caused by helium removal. When the outflow function has ended, stop valves can be switched, so that sub atmospheric pressure is built up again in the R1 rooms, and the exhaust air of the exclusion area is monitored as it is removed.

In these cases, there is restricted access to those room areas where the leak helium is released as a result of the accident. Sub atmospheric pressure in these room areas is automatically maintained by controlled supply air throttling, provided the leak is not larger than 0.2 kg/s.

To retain radioactive iodine and aerosols, a demand filter system is provided as an iodine absorption filter, with downstream suspended-matter filters. When necessary, the exhaust air from the R1 and R2 rooms, and also from the FE store, can be passed through these filters.

The pressure graduations for directed air flow from room areas with low activity release potential to those with high activity release potential are implemented by the following measures:

- Ventilation of the room areas via separate ventilation lines, with a separate analogue control loop for maintenance of sub atmospheric pressure in the building
- Design of the connections between the room areas as ventilation-partitioned penetration or airlock
- Requirements for the leak-proof characteristics of the building structure and its internals

Removal of the heat dissipated into the room air is performed essentially by circulating-air cooling systems. They are preferably installed at the location where the heat is produced.

The circulating air coolers for the FE store ventilation system are connected to the service cooling water system and the primary side with max. 35 °C supply temperature; all other coolers are supplied with 6 °C chilled water, produced in refrigerating sets.

6.1.2 Heating, Ventilation and Chilled Water Systems of the Steam Plant

The ventilated buildings and rooms, and the design of the individual systems, are shown in Table 6.1.2-1.

Table 6.1.2-1: Design Data for the Ventilation Systems in the Conventional Area

System component	Redundancy (%)	Air volume flow (m^3/h)
Switchgear building		
General area 1	1 x 100	1x 60 000
General area 2	1 x 100	1x 60 000
Cooling machine room 1	1 x 100	1x 15 000

System component	Redundancy (%)	Air volume flow (m^3/h)
Cooling machine room 2	1 x 100	1x 1 500
Elevator machine room	1 x 100	1x 1 500
control room, computer, staff amenities	2 x 100	2 x 22 000
Redundancy 1 with central ventilation station (CVS)	1 x 100	1x 16 000
Redundancy 2 with CVS	1 x 100	1x 16 000
Redundancy 3 with CVS	1 x 100	1x 16 000
Redundancy 4 with CVS	1 x 100	1x 16 000
Diesel engine 1	1 x 100	1 x 150 000
Diesel engine 2	1 x 100	1 x 150 000
Diesel engine 3	1 x 100	1 x 13 500
Diesel engine 4	1 x 100	1 x 13 500
Diesel engine 5	1 x 100	1 x 13 500
Diesel engine 6	1 x 100	1 x 13 500
Battery 1	1 x 100	1x 1 500
Battery 2	1 x 100	1x 1 500
Battery 3	1 x 100	1x 1 500
Battery 4	1 x 100	1x 1 500
Supply air smoke removal 1	1 x 100	1x 12 500
Supply air smoke removal 2	1 x 100	1x 12 500
Exhaust air smoke removal 1	1 x 100	1x 12 500
Exhaust air smoke removal 2	1 x 100	1x 12 500

System component	Redundancy (%)	Air volume flow (m^3/h)
In Turbine Hall		
Supply air systems 1 to 10	each 1 x 100	10 x 40 000
Exhaust-air systems 1 to 10	each 1 x 100	10 x 40 000
LTA in thyristor room 1 to 6	each 1 x 100	6 x 5 600
LTA in oil containment area 1 to 6	each 1 x 100	6 x 5 400
LTA elevator room	1 x 100	1 x 1 500
LTA cable duct	1 x 100	1 x 10 000
Supply air smoke removal	5 x corresponding to flow cross-sectional area	
Exhaust air smoke removal	10 x corresponding to flow cross-sectional area	
Stairwell smoke removal	2 x corresponding to flow cross-sectional area	
In Intermediate building		
Supply air systems 1 and 2	each 1 x 100	2 x 75 000
Exhaust-air systems 1 and 2	each 1 x 100	2 x 75 000
Smoke removal systems 1 to 5	3x 33 2 x 100	3 x 25 000 2 x 16 000
Condensate Clean-up Room		
Supply air system	1 x 100	1 x 200
Exhaust-air system	2 x 50	2 x 200
Air-recirculation cooling system	2 x 50	2 x 6 000

6.2 Water Treatment Plant

6.2.1 Condensate Clean-UP System

The condensate clean-up system is designed for 87 kg/s mass flow, and consists of 2 x 100 % pre-coating filters.

6.2.2 Demineralization System

The demineralization system is a service system, carries no radioactivity, and is not of importance in safety-engineering terms.

The demineralization system is used to prepare the demineralized water (deionized water) required for filling the systems and for compensating operating losses.

It is assumed that the raw water is free of bacteria and faecal matter. Raw water pumps pump the raw water to the demineralization system in the demineralization system building.

The demineralization system building houses:

- At elevation ± 0 m: the filters and the equipment of the ion exchange system
- In the basement: the storage basins and pump stations required for operating the system
- On the top floor: the central chemicals store and the associated transfer pumping station

The water is de-mineralized in an ion exchange system. In order to protect the ion exchange resins contained therein against mechanical soiling, a filtration stage is provided upstream of the system, consisting of 2 x 100 % gravel filters.

After flowing through the filtration devices, the mechanically cleaned raw water is stored in an intermediate tank, consisting of two mutually isolatable compartments. The water for backwashing the gravel filters is taken from this tank. The intermediate tank also serves as a store for cleaned fire-fighting water. The auxiliary cooling water system is also supplied from this tank.

The filtered raw water is pumped from the intermediate tank to the ion exchange system. This is made up of two mutually independent lines, with no cross-connections between the main water routes through the individual process stages.

The two lines can be operated in parallel if required. They must, however, be regenerated one at a time.

Each of the two demineralization lines consists of the following process stages:

- Cation exchanger, heavily acidic
- CO_2 degasifier
- Anion exchanger, heavily alkaline
- Mixed-bed filter

The demineralized water is stored in the demineralized water tank downstream of the demineralization system. The demineralized water tank is divided into two compartments, which can be isolated from one another. For carrying out repair work, one of the compartments can be taken out of operation, without having to restrict operation of the demineralization system.

The ion exchange resins are regenerated with NaOH, HCl and H_2SO_4, which are stored in the central chemicals store. In order to keep the chloride slip of the system as low as possible, the mixed-bed filters are regenerated with sulphuric acid. The ion exchange resins of both lines are regenerated by a common regenerating station.

The regenerating and washing water requirements of the system are supplied from the demineralized water tank.

The liquid waste which is produced when the ion exchanger systems are regenerated is neutralized in a neutralization pond. This is divided into two compartments, each of which can accommodate the liquid waste form regeneration of one exchanger line. Both compartments are connected in parallel, and are used in normal operation. For repair work, one compartment can be blocked off. The neutralized liquid waste is passed to the liquid waste collecting pond.

The demineralization system is operated and regenerated using a function group control system. The automatic program is made up of stepping criteria, which consist of process variables and timer elements.

The following functions are excluded from the function-group control system:

- Regeneration of the mixed-bed filter
- Backwashing of the ion exchange resins

These can be manually controlled from the mimic diagram.

After an operating standstill, the program begins with a re-circulated washing function, performed with the aid of a recirculation pump.

The demineralized water tank is filled to the specified level by the demineralization system. The line currently in operation is switched over to recirculation mode when the maximum level is reached, in a similar way to the re-circulated washing function. If one line is exhausted before the demineralized water tank has been refilled, the system switches over to the second line, if this has already been regenerated.

A command for parallel operation of both lines must always be initiated manually.

The non-local equipment for measuring, controlling and monitoring the system is grouped in a central control panel, located in a room in the demineralization system building. The most important operating parameters are transmitted to the power plant control room in the switchgear building, as is a general alarm signal. The demineralization system can be switched off locally and from the power plant control room by an "emergency stop" switch.

The switchgear installations belonging to the demineralization system are located in a switchgear room in the demineralization system building. Thanks to the switchgear and control panel being provided locally, the demineralization system can be operated independently of the switchgear building, provided a power supply and a water supply are available.

The conventional laboratory is located in the demineralization system building.

6.2.3 Chemicals Store

The chemicals store fulfils service tasks, carries no radioactivity, and is not of importance in safety-engineering terms.

6.2.3.1 Dimensioning

In normal operation, the tank contents are sufficient for:

- Caustic soda, ammonia and hydrazine: 15 days
- Hydrochloric acid and sulphuric acid: 30 days

The tanks are dimensioned so that a usual transport volume can be accommodated before draining.

6.2.3.2 System Description

The service chemicals for the demineralization system and the dosing system are stored in the chemicals store.

The store is located in the demineralization plant building, and consists of a store room for caustic soda, ammonia and hydrazine, plus a room for hydrochloric acid and sulphuric acid.

For receiving the service chemicals from tanker trucks by means of compressed-air draining appropriate reception connections (reception station) are installed at the demineralization system building. When caustic soda, hydrochloric acid and sulphuric acid are delivered in railway tanker wagons, this reception station can be shifted to the vicinity of the railway track.

The transfer pumps for supplying the various batch boxes and dosing tanks from the chemicals store are grouped together in a pump station. The switchgear, measurement and control equipment required for the store are housed in the cubicles of the demineralization system.

6.3 Liquid Waste Disposal Systems

The liquid waste systems in the reactor building, the reactor auxiliary building and the fuel element storage building are designed to collect the liquid waste produced in the exclusion area, to treat it, and to discharge the cleaned liquid waste. The systems involved are service systems.

They also provide the disposal function for the liquid waste from the condensate clean-up system of the water/steam cycle, if the waste is activated.

The systems themselves are not designed to withstand external events. They are located in building sections which are designed to withstand external events, and thus to collect the liquid waste in the hold-up troughs and sumps if the systems fail.

The requirements for materials, calculation, design, manufacture and erection, including the associated testing, conform to the conventional body of standards.

Preliminary testing beyond the specifications of the conventional body of standards is not performed, except for the 1st waste evaporator system and the concentrate collecting system.

6.3.1 Dimensioning

The dimensioning is based on the loads from operating inner pressure, dead weight, and thermal expansion, in accordance with the conventional body of standards.

6.3.2 Function and Construction

The liquid waste systems in the reactor building, the reactor auxiliary building and the fuel element storage building consist of:

- Water supply and disposal systems, which supply the consumers in the reactor building (RB), reactor auxiliary building (RAB) and the fuel element storage building with deionized water, and collect the possibly activated liquid waste in these buildings.
- A hold-up trough, in which the liquid waste is held and kept in intermediate storage as required by its activity and composition.
- A chemical mixing system for conditioning the water involved.
- A filter system and a two-stage waste evaporator system, for cleaning and treating the collected liquid waste.
- A distillate and filtrate collecting system, for intermediate storage of the cleaned water before it is passed to the service liquid waste transfer station.
- A concentrate collecting system for intermediate storage of the radioactive concentrate produced in the waste evaporator system, and of the substances filtered out at the filter system.
- A sampling system for analysing the liquid waste.
- A service water transfer station, serving for monitored discharge of the service liquid waste from the RB/RAB.
- A steam-to-steam heat exchanger system, which adjusts the steam to the state required for the waste evaporator system.

6.4 Compressed Air System

The compressed air system generates both station air and control air for:

- Ventilation
- Refuelling system
- Helium purification system

It is a service system, and is not important in safety engineering terms. For consumers with safety-engineering importance, the control and regulating valves are of fail-safe design.

The distribution networks need not be designed to withstand external and internal events. The configuration of the piping is designed to ensure that no consequential damage occurs at systems which are important in safety-engineering terms.

6.4.1 Dimensioning

The compressed air requirement for station air during power plant inspections is approximately 700 m^3/h (under normal conditions). An additional quantity of approximately 120 m^3/h (i.n.c.) is required for the decontamination system.

The compressed air requirement for control air during power plant operation is provided by a compressor with an output of 750m^3/h (i.n.c.).

The piping network installed for station air is separate from that installed for control air.

The compressed air generating system, including the distribution networks, is dimensioned so as to ensure that at least 13 bar pressure is available to all control air consumers.

6.4.2 Function and Construction

The oil-free control and station air for the nuclear power plant unit is generated by one common compressed air generating system, which is located in the auxiliary boiler building. The demineralization system and the condensate clean-up system are provided with their own compressors for low-pressure compressed air, to be used in loosening filters and ion exchangers.

The compressed air generating system consists of three water-cooled dry-running compressors with intercoolers and after coolers, which are connected to the compressed air tank via a header and air drying systems.

The compressed air tank feeds:

- The station air system via a flow limiter
- The control air system

The air intake sucks in air from the atmosphere and filters it. The flow limiter keeps severe pressure fluctuations, such as may occur if large quantities are removed, away from the compressed air tank and thus away from the control air system.

The control air is filtered downstream of the storage tank and fed into the control air system; reducing valves, upstream of the consumers, are provided to reduce the pressure to the level required for the valves and controllers.

The auxiliary cooling water system supplies cooling water for the compressors, the air cooler and the refrigerating drier.

The compressors are dimensioned so as to ensure that during normal operation one machine works intermittently. A pressure monitor is installed at the compressed air tank to provide a switchover function from no-load mode to load mode. If one compressor is temporarily not sufficient to cover the entire air requirement, then the reserve machine is automatically brought on line by pressure monitors adjusted in graduated steps.

The individual power plant buildings are connected to the common compressed air tank via distribution pipes. Outside the buildings, the station air and control air pipes are laid as far as possible in existing conduits, or in the ground. Inside the buildings, consumers are connected to the air system concerned via annular and spur lines.

The compressed air supply systems are switched locally, and monitored from the control room.

6.5 Fire Protection Systems

The fire-fighting water systems of the NSSS unit are supplied with fire-fighting water from a central pump station.

The task of the fire-protection measures is to

- prevent fires
- detect fires at an early stage
- inhibit the spread of fires
- minimize consequential damage

These tasks are fulfilled by passive and active fire-protection measures.

The fire-protection systems are service systems, and are not important in safety-engineering terms.

System Description

1. Passive Fire Protection

The term "passive fire protection" subsumes measures designed to prevent fires from starting or to inhibit their spread. This includes in particular the following measures:

- Sub-division of the buildings into fire-fighting sections and fire-resistant zones
  - Individual buildings, such as the reactor building, the reactor auxiliary building, the intermediate building, switchgear building, condensate clean-up system building and turbine hall, are considered as fire-fighting sections.
  - The buildings are subdivided into fire-fighting sections insofar as this is feasible machinery wise.
  - Rooms located within fire-fighting sections having increased fire hazard or a more stringent protection requirement are subdivided into fire-resistant areas, e.g. oil tank rooms, emergency generator rooms, transformer rooms, computer rooms.
- Escape route planning

Stairwells are fitted with fire-protection walls and appropriate fire-protection doors to form protected escape routes. These stairwells incorporate an exit into a protected area, if possible into the open air.

- Partitioning of openings in walls and ceilings with fire-protection requirements
  - When pipes, cables and ventilation ducts are passed through structural parts with fire-protection requirements, partitions are used with a fire-resistance class.
  - All doors and gates functioning as fire-protection closures in fire-protection walls are designed as fire-resistant doors.
  - Doors and gates within the limits of fire-proofed areas are in self-closing design. The fire-resistance class is laid down in conjunction with the fire-fighting authorities.
- Fire protection at electrical systems
  - Closed-off electrical system rooms are separated in fire-resistant design
  - Cable trunking and ducts are designed as fire-resistant areas.
  - Relatively long cable trunking runs are partitioned fire-protection wise at 40 m to 60 m intervals - especially in the vicinity of branch-offs, crossings and near the transition of a cable trunking section into a cable duct.
  - Power, control and measuring cables of one redundant system are led together on one route; power cables are laid on separate racks.
  - For cable insulation and cable jackets, flame-retardent materials are used, e.g. certain thermoplastics on a PVC basis.
  - Cables are always laid so as to avoid crossing parts which carry flammable or corrosive media.
- Fire protection at ventilation systems
  - The materials used for ventilation ducts are basically non-flammable materials.

- Insofar as the use of flammable materials cannot be avoided for technical reasons, e.g. in the case of corrosive exhaust air, then at least flame-retardent materials are used.
- If ventilation ducts are led through other fire-fighting sections, they are either insulated or separated by fire-protection valves at the interfaces.
- Ducts which are used for smoke removal are designed to be fire-resistant if they cross other fire-fighting sections.

2. Active Fire Protection

The term "active fire protection" subsumes measures and equipment for actually fighting fires. These complement the measures listed under passive fire protection.

Fire-Fighting Water System

Hydrants and water spray extinguishing systems are supplied from the extinguishing water system.

This consists essentially of:

- 2 fire-fighting water basins, each of 600 m^3 capacity. The fire-fighting water basins serve simultaneously as storage basins for gravel-filtered water in the water treatment system
- 4 fire-fighting water pumps , each with 55 kg/s delivery flow, 100 m delivery head
- 2 pressure-maintenance pumps, each with 11.1 kg/s delivery flow, 100 m delivery head
- The buried outer ring of the fire extinguishing piping network, including hydrants and gate stop valves (section gate valves)
- The spur, riser, connecting and in some cases ring lines inside the buildings, including the wall hydrant cabinets and the cabinet installation combinations

The 4 x 50 % fire-fighting water pumps are connected to the emergency power network.

The pressure in the fire-fighting water network is dictated by 2 x 100 % pressure-maintenance pumps.

The design delivery flow is based on the requirement of the largest water spray extinguishing system, plus 25.7 l/s hydrant is present.

One fire-fighting water tank is refilled in 8 h.

The outer ring of the fire-fighting water line consists of ductile cast iron, whose material characteristics withstand the stresses occurring in the fire-fighting water system in regard to fracture less deformability in the event of impact, bump and bending, plus non-susceptibility to pressure surges and vibrations. The pipe connections are in sleeve connection design. The longitudinal forces are absorbed by special thrust-protected sleeves, thus rendering concrete abutments superfluous. The angle-flexible construction of the sleeve connections means that the buried network remains functional even in the event of ground subsidence.

The outer ring is subdivided by gate stop valves so as to ensure that the section of the network not affected remains functional during embedment and repair work.

Columns and spindles of the hydrants are provided with predetermined breaking points, so that mechanical damage to a hydrant cannot result in a failure of the entire network. The damaged hydrant itself can be repaired within a short time. The hydrants are located at tactically favourable positions, e.g. at rubble-shadow distance in front of the buildings. The guideline figure for distance between hydrants is 60 m.

Connections are provided for emergency supply of water into the fire-fighting water network via portable pumps.

Spur lines lead from the outer ring into the buildings, and are continued inside the buildings with a minimum nominal diameter of 80 mm, as a riser or ring line. All risers are designed as wet risers, since in view of their path inside the building there is no risk of freezing.

Wall hydrant cabinets or cabinet installation combinations are located in the stairwell areas, the escape routes, and the preferred attack routes during active fire-fighting. They are distributed among the individual building elevations so that every endangered point can be served.

Fixed Fire-Fighting Equipment

Fixed location fire-fighting equipment is installed when

- Rooms are difficult to access or cannot be entered
- Extinguishing agents must be used very promptly in the event of a fire

The fixed extinguishing systems used are water spray and halon types.

Water Spray Extinguishing Systems

These are used to protect rooms and objects where a high fire load is involved, and water is suitable as an extinguishing agent.

The water spray extinguishing systems are each supplied by a spur line from the fire-fighting water system.

A fire-fighting zone is delimited so that it does not exceed the boundaries of the fire-fighting section or fire-resistant area. Adequate water disposal systems are provided in rooms where water spray extinguishing systems are installed, in order to prevent the fire-fighting water spreading to adjacent rooms.

The water spray extinguishing system for the open-air transformers is triggered automatically. The extinguishing function is interrupted automatically by a timer element. There are options for after-flooding by manual remote triggering from the control room and manual triggering on the spot.

The other fire-fighting systems are triggered by hand, either by remote control from the control room, or on the spot.

Triggering of any fire-fighting system is indicated in the control room.

The water accumulating in the reactor building and the reactor auxiliary building is collected in hold-up tanks, and then passed to the radioactive liquid waste treatment system.

Halon Extinguishing Systems

Halon extinguishing systems are used where water cannot be employed, or where damage from fire-fighting water cannot be accepted.

Halon extinguishing systems are provided for the computer rooms and the associated cable floors in the switchgear building.

The halon supply is accommodated in two batteries of cylinders, of which one is a 100 % reserve, in a separate room located in the immediate vicinity of the fire-fighting zones.

The halon quantity, which is different for each room, is taken from the cylinder battery in the event of a fire, and passed via the assigned fire-fighting zone valve to the fire-fighting zone concerned.

Before the extinguishing systems are triggered, an acoustic and visual alarm is given on the spot.

The halon system is automatically controlled by the fire alarm system. The triggering function is initiated by two-loop independent signals. The system can be triggered by hand on the spot for each fire-fighting zone (push-button alarms). When the system has been triggered, a check back signal is sent to the fire-protection panel.

6.6 Hoists and Elevators

Number and design of the lifting equipment and elevators are listed in Table 6.6-1 and Table 6.6-2.

Table 6.6-1: Lifting Equipment

Building	No.	Application	Load (t)	Travel (m)	Type
Reactor building	1	Bridge crane	100	52	Cable/electric

Building	No.	Application	Load (t)	Travel (m)	Type
Reactor auxiliary building	1	Bridge crane	25	11.5	Cable/electric
Reactor auxiliary building	1	Hoist for erection aperture	3	23	Cable/electric
Fuel element store	1	Gantry crane for fuel element transportation	1	10	Cable/electric
Fuel element store	1	Hoist for erection aperture	3	10	Cable/electric
Condensate clean-up room	1	Hoist for filter	6	13	Cable/electric
Turbine hall	1	Bridge crane	80/10	20	Cable/electric
Intermed. building	1	Bridge crane	3	8	Cable/electric
Intermed. building	2	Hoist for auxiliary feedwater pumps	1	4	Chain/hand
Intermed. building	1	Hoist for erection aperture	3	22	Cable/electric
Switchgear building	2	Hoist for Diesel components	10	6	Chain/hand
Switchgear building	2	Hoist for Diesel components	10	6	Chain/hand

Table 6.6-2: Elevators, Special Gates

Building	No.	Application	Load (t)	Cage (m)	Doors	Floors
Reactor building	2	Pers/goods	2	2.2 x 2.2	1-side	9
Turbine hall	1	Pers/goods	3	3.0 x 2.0	2- side	5
Switchgear building	1	Pers/goods	3	3.0 x 2.5	2- side	7

Auxiliary building	1	Pers/goods	3	3.0 x 2.5	2- side	5
Building	**No.**	**Application**	**Load (t)**	**Gate (m)**	**Material**	**Transport Path (m)**
Fuel element store	1	Lifting gate	300		Cast steel	4.5
Fuel element store	1	Sliding gate	100		Concrete	4.5
Fuel element store	1	Sliding door large	30		Cast steel	2.2
Fuel element store	2	Sliding door small	15		Cast steel	1.8
Reactor building	1	Sliding gate	80		Cast steel	4

6.7 Auxiliary Steam and Auxiliary Condensate System

The auxiliary steam and auxiliary condensate system is a service system, carries no radioactivity, and is not of importance in safety engineering terms.

System Description

The auxiliary steam system serves to supply the steam consumers with heating and process steam. The steam consumers belong both to the primary section and to the secondary section of the power plant.

In order to ensure the supply to the auxiliary steam consumers at all times, the auxiliary steam network is fed from various steam sources via a common-header system depending on the current operating mode of the power plant.

The steam consumers are connected to a common-header system, which, depending on the operating mode of the power plant, is fed from the following steam sources:

Operation mode	Steam source
Cold start	Auxiliary boiler
Cold start after inception of nuclear steam generation	Live steam pipe via reducing station
Warm start	LS pipe via reducing station
Full-load operation	Extraction from HP turbine
Part-load, operation	Live steam (LS) pipe via reducing station and extraction from MP turbine
Shutdown of plant into cold state	Up to c. 9 bar from LS pipe, below that from auxiliary boiler
Power plant shutdown	Auxiliary boiler

The circuit is structured so that the auxiliary steam system can be operated independently of the operating state of the water/steam cycle of the main plant. This enables trial runs to be carried out for sub-systems of the power plant, and also allows the heating system to be operated before initial start-up of the power plant. Auxiliary steam consumers can continue to be supplied if the power plant is subsequently taken out of operation.

The heating condensates from the consumers connected to the auxiliary steam system are collected in the condensate collecting tank. From here the condensate is pumped to the auxiliary feedwater tank by one of the 2 x 100 % auxiliary steam condensate pumps. 2 x 100 % auxiliary feedwater pumps are provided for feeding the electric boiler.

When the auxiliary steam consumers are supplied from the LS pipe or from the extraction from the MP turbine, the condensate is returned from the condensate collecting tank via the condenser to the feedwater tank. 2 x 100 % condensate collecting pumps are provided for this purpose. No heating condensate from the monitored area is returned to the water/steam cycle or the auxiliary feedwater tank.

De-aerator and auxiliary feedwater tank are connected to the auxiliary steam network via their own reducing station.

In order to fill the system with cold condensate before start-up, and to cover steam and condensate losses during actual operation, a connection is provided between the auxiliary feedwater tank and the condensate storage tank. The make-up condensate is conveyed by 2 x 100 % make-up condensate pumps.

Feed into the auxiliary feedwater tank is level-controlled using a make-up condensate pre-heater, which is also connected to the auxiliary steam network. If the water level in the auxiliary feedwater tank is too high, then a drain controller is opened, and the excess water is drained off into the condensate collecting tank.

Any repair or pressure test at the auxiliary feedwater tank is possible without having to interrupt the supply to the auxiliary steam consumers. This, however, presupposes that the steam supply is coming from the LS header or from the extraction from the MP turbine, and not from the auxiliary boiler.

If the mains fail, then steam supply from the auxiliary boiler is not possible.

The auxiliary steam header is protected against overpressure by a safety valve.

The auxiliary boiler system is fitted with the equipment for controlling and limiting the main operating variables, which enable the system to be operated without local supervision. Start-up and shutdown of the auxiliary boiler system is carried out on the spot.

The electrical systems for operating the electric auxiliary boiler system are located in the switchgear room of the demineralization system. The control, measuring and monitoring systems are grouped in a local control panel. The measured values for the main operating parameters are transmitted to the power plant control room, as is a general alarm signal, which triggers visual and acoustic indication that an important operating variable is approaching the non-permissible limit value. If the permissible limit value for an operating variable is exceeded, the heating function of the auxiliary boiler system is automatically switched off and locked; the auxiliary boiler system is started up again on the spot. The boiler system can be switched off locally and from the power plant control room by an emergency stop switch.

Thanks to the local location of switchgear installations and control stand, the auxiliary boiler system can be started up independently of the operational readiness deadline for the switchgear building, provided that a power supply and demineralized water are available.

The power supply for starting up the electric boiler is ensured by early completion of the outside system transformer.

6.8 Dosing System

The dosing system is a service system, carries no radioactivity, and is not of importance in safety-engineering terms.

System Description

The dosing system feeds

- ammonia and hydrazine into the water/steam cycle,
- ammonia into the secondary component cooling water system,
- ammonia into the main cooling water system.

The pH value required is attained by dosing ammonia, while hydrazine dosing is used to detach oxygen, and thus to minimize the corrosion rate in the cycles.

The dosing system is located in the condensate clean-up system building. The system consists of 3 lines. One line is provided for ammonia and one line for hydrazine dosing, while the third line serves for demand dosing of ammonia and/or hydrazine. The ammonia and hydrazine lines incorporate 2 dilution and dosing tanks, plus 2 x 100 % dosing pumps. The demand dosing line consists of a dilution and dosing tank with 2 x 100 % dosing pumps. Each tank is fitted with a level indicator and fill level contacts. The dosing pumps in the ammonia and hydrazine lines are fitted with variable-speed drives.

The individual dosing points provided are as follows:

for ammonia

- main condensate pipe downstream of condensate clean-up system (continuous)
- upstream of condensate storage tank

for hydrazine

- suction pipe of feedwater pumps (continuous)
- upstream of condensate storage tank
- overflow pipe downstream of moisture separator (continuous)

for demand dosing

- feedwater tank
- header upstream of recirculation pumps for component and service cooling water system
- main cooling water pipe upstream of main cooling water pumps

The demand dosing points are operated by hand, if the analysis measurements in the system concerned show that additional dosing is required.

Dosing of ammonia and hydrazine upstream of the condensate storage tank is necessary only at start-up.

The dosing system is supplied with ammonia and hydrazine from the central service chemicals store in the demineralization system building. Deionized water is used to dilute the chemicals. All tanks are connected both to the ammonia and to the hydrazine supply pipe, so that the option exists of dosing an ammonia/hydrazine mixture if necessary.

6.9 Sampling System

The secondary sampling system is a service system, does not carry any radioactivity, and is not of importance in safety-engineering terms.

System Description

The secondary sampling system serves for chemical monitoring of the water/steam cycle, the auxiliary boiler system, the component and service cooling water systems and the main cooling water system.

Monitoring is carried out by means of:

- Taking laboratory samples
- Continuous measurement of conductivity, pH value, oxygen content and silicic acid content
- Recording important measured values by pen recorders, display units and limit value signalling on the local panels and in the control room.

Instead of pH measurements, conductivity difference measurements are performed, i.e. the difference in conductivity before and after a highly acidic cation exchanger is determined. The concentration of the alkalization agent can thus be determined more accurately than with pH-measurement.

The samples are taken with a probe, cooled by the sample cooler, thermo stated if necessary, and fed to the measuring instruments.

If samples are taken from parallel lines, then only one sample cooler with measuring device is used for 2 sampling points. By operating the appropriate stop valves, the unit can be switched over to the parallel sampling point.

The sample coolers for samples from the water/steam cycle are grouped on a small number of frames. Since corrosion products are deposited in the sampling pipes, i.e. the Fe results from the laboratory samples drawn are inaccurate, local sampling fittings are provided at some points, to which a portable cooler can be connected. Thus from time to time the deviation of the Fe value measured at the sample frame from the local value can be measured. Local modular panels are provided for taking samples from the condensate tank, the collected condensate tank and the auxiliary steam system. The measured values are recorded.

The coolers for samples from the water/steam cycle are connected to the secondary component cooling water system; the coolers for samples from the auxiliary boiler and auxiliary condensate system are connected to the auxiliary cooling water system.

7 Steam Power Plant

7.1 Water Steam Circuit

7.1.1 Overall Circuit

The steam power plant of the twin unit has the purpose

- to transfer the heat generated by the NSSS in order to
  - provide industrial steam and
  - electricity,
- to remove decay heat after reactor shut down and
- to provide the plant with electricity and steam.

Component List

The components are listed in Table 7.1.1-1.

Table 7.1.1-1: Component List

Low pressure (LP) feedwater heater	Stage 1
LP feedwater heater	Stage 2
LP feedwater heater	Stage 3
LP feedwater heater	Stage 4
Feedwater tank with deaerator showers	Stage 5
Flash tanks	
Condensate tank	
Condensate storage tank	
Condensate collecting tank	
Main feedwater pump sets	
Main condensate pump sets	
Condensate collecting pump sets	
Pipes	

Isolation valves, safety valves
Thermal insulation

Requirements

The water/steam circuit is a service system. It passes low quantities of radioactivity, which must be monitored. In the intermediate building and in the turbine hall, the water/steam circuit is not of importance in safety engineering terms.

A failure in these areas does not result in impairment of the decay heat removal function, since the systems provided for this function are geographically distant or protected against the effects of a failure by structural measures. In the reactor building, the live steam and the feedwater lines are protected against internal and external events up to and from the fixed point in the wall of the reactor building, and dimensioned and manufactured against failure. This design of the water/steam circuit ensures that the service system will not damage any component of safety engineering relevance in the reactor building.

The water/steam circuit can also remove the decay heat as a service system. The valves located outside the reactor building in the live steam and feedwater lines are not intended to retain radioactivity, but are designed purely for operating tasks. They are not dimensioned to withstand internal and external events.

Dimensioning

The water/steam circuit inside the reactor building is designed against failure; this is ensured by suitable choice of materials, lower stress level, quality assurance, and by In-Service Inspections. The leakage cross-sectional area is limited to 0.5 % pipe cross-sectional area.

To protect the NSSS from non-permissible effects from a pipe fracture occurring outside the reactor building, a fixed point is located for each pipe on the inner side of the reactor building, decoupled from the outer wall of the reactor building. Inside the biological shield, the pipes are fitted with conduits, which serve as steam-carrying pipes in the event of a leakage in the media pipe.

The Isolation valve installed in every LS pipe and the flow-medium-controlled safety valve, plus the LS header are located outside the reactor building in the intermediate building. The LS pipes are in failure-proof design from the steam generators up to the fixed point in the wall of the reactor building.

They are open towards the pipe shaft, which vents into the intermediate building. In addition, the pipes are dimensioned to withstand a pressure surge resulting from the pipe fracture. In the intermediate building and the turbine hall the water/steam circuit is designed in accordance with the standard specifications currently applicable for the construction of coal-fired power plants.

System Description

The water/steam circuit incorporates those systems of the secondary section of the nuclear power plant directly involved in power generation. The main systems concerned are those for live steam, main condensate, LP and high pressure (HP) feedwater heating, feedwater, extraction steam, and heating condensate.

The main data and circuitry are shown in the heat flow diagram in Figure 7.1.1-1 and in Table 7.1.1-2 to Table 7.1.1-4.

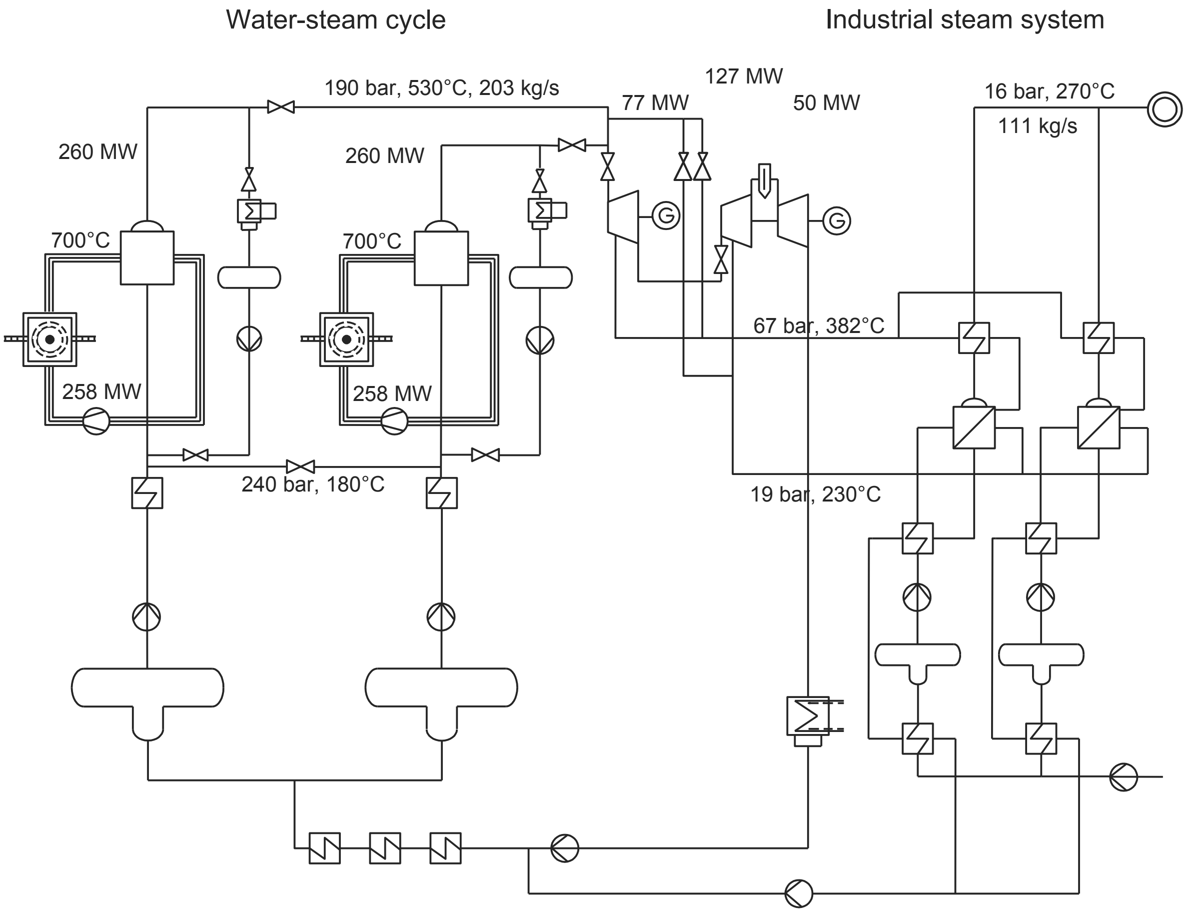

Figure 7.1.1-1: Heat Flow Diagram

Table 7.1.1-2: Technical Data of Steam Power Plant

	Industrial steam (t/h)	Electric power (MW)
Normal operation	170	176.7
	400	126.7
	500	98.8

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	Industrial steam (t/h)	Electric power (MW)
Loss of HP turbine	400	87.5
Loss of IP/LP turbine	400	93.7

Table 7.1.1-3: Water-Steam Circuit

Live steam temperature	°C	530
Live steam pressure	bar	190
Live steam mass flow	kg/s	202.4
Feed water temperature	°C	180
Feed water pressure	bar	240
Power range	%	40 - 103

Table 7.1.1-4: Industrial Steam Plant

Return temperature	°C	20
Return pressure	bar	variable
Return mass flow	kg/s	46.7 – 134.7
Live steam temperature	°C	270
Live steam pressure	bar	16
Redundancy	%	2 x 65
Pre-heater stages	-	5
Steam flow range	t/h	170 - 500

Live Steam System

The live steam flows from each of the two steam generators in two separate pipes to two headers in the intermediate building, and from these to the live steam collector which is upstream of the two admission valves of the HP turbine.

Two additional lines connect the live steam collector to the IP/LP-turboset and the steam converter and superheater of the industrial steam plant via two live steam expansion stations.

The start-up and shutdown system assigned to each reactor is also connected to the headers. The steam generator bundles can be individually separated from the headers. The steam generators are protected against overload by safety valves.

The Isolation valve installed in every LS pipe and the flow-medium-controlled safety valve, plus the LS header are located outside the reactor building in the intermediate building. The LS pipes are in failure-proof design from the steam generators up to the fixed point in the wall of the reactor building.

From the LS pipe, the pipes branch off to the turbine bypass valve, which is connected in parallel with the start-up regulating valves, for supporting steam supply to the feedwater tank and the auxiliary steam header. The 1 x 100 % turbine bypass valve is dimensioned for the live steam mass flow at full load, so that the entire quantity of excess steam produced during start-up and shutdown functions and during load-shedding can be passed to the turbine condenser.

The bypass assembly consists of a combined emergency-stop and regulating valve with water injection chamber. The injection water is removed from the condensate tank of the air-cooled condenser by the main condensate pumps.

After expansion in the IP turbine section, and before entering the LP turbine sections, the steam is drained via high-speed moisture separators installed in the two exhaust steam pipes of the IP turbine section, in order to avoid impermissibly high exhaust moisture and the associated risk of erosion. After being drained in the LP turbine section, the steam is condensed in an air-cooled condenser. This is divided on the steam side into 2 sub-condensers.

Main Condensate System and LP Feedwater Heating System

The main condensate passes from the condensate tank of the air-cooled condenser via the condensate collecting pipe to the main condensate pumps. The 2 x 100 % electrically powered main condensate pumps pass 50 % of the condensate mass flow in normal operation via the pre-coat filter of the condensate cleaning system (CCS) and the total mass flow to the LP feedwater heating system, and then to the feedwater tank. The CCS can be bypassed. In bypass mode, one of the main condensate pumps supplies the injection water required, so that the second pump acts as a stand-by.

The mass flow from the main condensate pumps is adjusted in dependence on the level in the hotwell, via the outflow regulating valve. Overfeeding of the feedwater is prevented by throttling this outflow regulating valve. The minimum flow for the main condensate pumps is guaranteed by a minimum-flow valve, which opens and closes in dependence on the condensate mass flow.

Independently of the regulating system for the main condensate pumps, the feedwater tank is fitted with an inflow and an outflow regulating system If the level is too low, the outflow regulating valve passes condensate from the cold condensate storage tank to the feedwater tank. If the level is too high, the inflow regulating valve admits condensate from the main condensate pipe behind the condensate cleaning system to the cold condensate storage tank. A cushion of steam from the auxiliary steam system prevents the admission of oxygen.

The LP feedwater heater line is constructed in single-line design. A common bypass is provided for stages 1 and 2, and for stages 3 and 4. The extraction pipes for stages 1 and 2 cannot be isolated, while the stage 3 pipe and stage 4 pipe are protected against water backflow with a controlled check valve.

The heating steam condensate passes from LP feedwater heater stage 4 via stage 3 to stage 2 and stage 1, and from there directly to the condensate tank of the condenser. In addition to the normal drain, each feedwater heater is fitted with an emergency drain, leading to the flash tank, at the condensate tank of the condenser.

The condensate collecting in the moisture separators of the turbine is fed into LP feedwater heater 3, and can thus be purified in the condensate clean-up system. The water/steam circuit is operated at a pH value of 9 to 9.5. Thanks to the use of unalloyed steel pipes in the air condenser and the stainless steel pipes in the LP preheaters in conjunction with this high pH value, only very small quantities of corrosion products are formed in this circuit, so that the steam generators are not soiled either. The material for the extraction lines is suitable for withstanding erosion from the water in the extraction steam.

Downstream from the LP feedwater heaters is the feedwater tank, which functions as a mixing-type heater, and is fitted with two spray de-aerators. It works with load dependent heating steam pressure. The heating steam is taken from the extraction of the IP turbine section and the LP turbine sections. The pipe is protected against water backflows by means of two controlled check valves. If the extraction pressure during start-up and shutdown, and in low-load operation, falls below the requisite de-aerating pressure, then the pressure in the feedwater tank is supported by pressure-reduced steam from the live steam circuit.

The make-up water for covering circuit losses is supplied by a demineralizing system. The deionized water from this system is pumped into the condensate tank of the condenser. The inflow quantity is regulated in dependence on the level in the cold condensate storage tank. The deionized water pumps also supply the feedwater tank of the auxiliary steam system.

Feedwater System

In normal operation, and in bypass mode, the 3 x 50 % feedwater pumps pass the feedwater from the feedwater tank via the feedwater piping system to the header in front of the steam generators. The steam generators can be shut off on the feedwater side at the headers.

The feedwater volume is regulated by means of full-load and low-load regulating valves for each steam generator. Upstream of the feedwater regulating valves, which are installed outside the reactor building, an emergency isolation valve is provided, which serves to cut off the feedwater supply to the steam generators promptly in the event of accidents.

Start-Up and Shutdown Systems

For start-up and shutdown, each steam generator is provided with a start-up and a shutdown regulating valve at the feedwater side. The two shutdown regulating valves at the live steam side are connected in parallel to the turbine bypass valves, and the steam expands in the turbine condenser. The injection water is provided by the main condensate pumps.

Drain System

A condensate collecting tank with flash tank is provided for system draining. The condensate collecting here is pumped by the collected condensate pumps to the turbine condenser, unless it must be rejected.

Piping systems and tanks are drained in the building drainage system, which is monitored for radioactivity.

For the internal turbine drains, the system incorporates a flash tank, which is connected to the turbine condenser.

Venting System

The turbine condenser and the LP feedwater heaters are connected to a common venting system.

For partial venting of the turbine condenser during start-up, a large water ring pump with upstream gas ejectors is provided, while for venting during operation the system incorporates small water ring pumps with upstream gas ejectors.

Leak-off System

The external compartments of the turbine glands are connected to a vapour leakoff system, which is linked to the gland steam condenser. This condenser is cooled with main condensate, with the cooling function ensured even at minimum-quantity flow from the main condensate pumps, in low-load operation and before turbine start-up. The condensed steam passes into the turbine condenser, while a circulator passes the extracted air to the atmosphere.

Seal Water System

Glands with seal-water connection are provided for all valves from DN 50 upwards which in normal operation are under vacuum. The seal water is taken from the pressure side of the main condensate pipe.

Concept for Tritium Removal

Tritium permeates through the walls of the steam generators into the water/steam circuit. In order to prevent an accumulation of tritium in the water/steam circuit, the water is exchanged continuously. The water exchange rate is composed of the operating leakages and an intentional drain rate.

If the tritium concentration permitted in the water/steam circuit rises, the exchange rate can be appropriately reduced to a quantity which may already be covered by the operating leakages, so that in this case an additional drain-off function can be dispensed with completely. The reduction is ultimately limited by the activity resulting from evaporation of operating leakages and entering the room air of the turbine hall, which is classified as a monitored operating area, and is also limited by any officially laid down limit values for the drain-off water.

On the assumption that the exchange rate is covered by drain-off, then the tritium concentration in the drain-off water must be maintained below the officially approved maximum.

The turbine hall, together with any drain-off, is monitored in accordance with KTA 1504, by means of redundant continuously-measuring gamma measuring equipment. If the limit value is exceeded, then the drain-off function is aborted immediately.

7.1.2 Main Components

Low Pressure Feedwater Heater

Construction of LP Feedwater Heaters 1 and 3:

- Vertical surface condensation pre-heater with bottom-located water box
- Jacket tube and water box welded with tube-sheet
- U-shaped curved heat exchanger tubes roller-expanded into the tube-sheet
- Tube nest positioned inside shell with support plates to allow for thermal expansion and contraction

Construction of LP Feedwater Heater 2:

- As above
- With built-in condensate cooling zone.

The design data is given in Table 7.1.2-1 and in Table 7.1.2-1 the material data respectively. Thermal operating values as given in the heat flow diagram.

Table 7.1.2-1: Design Data LP Feedwater Heater

Pre-heater stage	**-**	**1**	**2**	**3**	**4**
Medium		Steam/Condensate			

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Pre-heater stage	-	1	2	3	4
Number of lines	%	1 x 100			
Condensate cooler	-	no	yes	no	yes
Condensate speed	m/s	2.0	2.0	2.0	2.0
Pressure loss, tube side	m	7.0	8.0	7.0	8.0
Design pressure, tube-side	bar	37	37	37	37
Temperature, tube-side	°C	120	120	150	180
Pressure, shell-side	bar	Vac-1	Vac-2	Vac-3	Vac-6
Temperature, shell-side	°C	120	120	150	180
Length	m	10	11	10	11
Diameter	m	1.6	1.6	1.6	1.6

Table 7.1.2-2: Materials LP Feedwater Heater

Tubes (longitudinal-seam-welded)	X10 CrNiTi 189
Shell	WStE36
Tube-sheet	WStE36

Main Feedwater Tank

Construction:

- Mixing-type heater with variable heating steam pressure
- Horizontal tank made of cylindrical, longitudinal-seam-welded multi-section jacket plates, with dished ends and 2 manholes
- Spray de-aeration for thermal de-aeration in the load range 20 - 100 % with showers controlled automatically by spring force to open a spray cross-sectional area corresponding to the quantity of main condensate
- Heating steam in-feed via a manifold located in the steam space, and admission of steam via submerged pipes into the feedwater

Thermal operating values as given in heat flow diagram.

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Table 7.1.2-3: Design Data Main Feedwater Tank

Medium	-	Steam/Condensate
Number of lines	%	1 x 100
Pre-heater stages	-	5
Total capacity	m^3	200
Useful capacity	m^3	180
Design pressure	bar	Vac-12
Design temperature	°C	250
Residual oxygen content	mg/l	0.005
Length	m	24
Diameter	m	3.3

Table 7.1.2-4: Materials Main Feedwater Tank

Shell/ends	WStE36
Spray deaerator components coming into contact with water Stainless steel	Stainless steel

Flash Tank

Construction

- Vertical tank with cylindrical jacket plates, with dished ends and manhole
- Tangential inflow of the 2-phase mixture for expansion

Table 7.1.2-5: Design Data Flash Tank

Medium	-	Steam/Condensate
Total capacity	m^3	7.5
Operating pressure	bar	4
Operating temperature	°C	200

Design pressure	bar	6
Design temperature	°C	250

Table 7.1.2-6: Materials Flash Tank

Tank	15 Mo 3
Lance	13 CrMo 44

Condensate Storage Tank

Construction

- Spherical tank made of segment-shaped, longitudinal-seam-welded courses linked by circular welds
- With built-in U-shaped loop
- Access via ladders and steps

Table 7.1.2-7: Design Data Condensate Storage Tank

Medium	-	Condensate
Total capacity	m^3	320
Useful capacity	m^3	300
Operating pressure	bar	1.2
Operating temperature	°C	105
Design pressure	bar	Vac-4
Design temperature	°C	260
Diameter	m	8.5

Table 7.1.2-8: Materials Condensate Storage Tank

Support	St 37-2
Jacket	H I + H II

Condensate Collecting Tank

Construction

- Horizontal tank made of cylindrical, longitudinal-seam-welded jacket plates with dished ends and manhole

Table 7.1.2-9: Design Data Condensate Collecting Tank

Medium	-	Condensate
Total capacity	m^3	70
Useful capacity	m^3	65
Operating pressure	bar	1.1
Operating temperature	°C	102
Design pressure	bar	3
Design temperature	°C	120

Table 7.1.2-10: Materials Condensate Collecting Tank

Shell/ends	RSt 37-2

Condensate Tank

Construction

- Horizontal tank made of cylindrical, longitudinal-seam-welded jacket plates with dished ends and manhole

Table 7.1.2-11: Design Data Condensate Tank

Medium	-	Condensate
Total capacity	m^3	50
Useful capacity	m^3	40
Operating pressure	bar	0.3
Operating temperature	°C	63

Design pressure	bar	Vac-1
Design temperature	°C	120

Table 7.1.2-12: Materials Condensate Tank

Shell/ends	RSt 37-2

Main Feedwater Pump Sets

Construction

Each pump set consists of:

- Booster pump
- Motor
- Transmission gear
- Main pump

The sets are mounted on vibration-damped concrete foundations.

Table 7.1.2-13: Design Data Main Feedwater Pump Sets

Operating value	**Unit**	**Value**
Redundancy	-	4 x 65 %
Medium	-	Feedwater
Delivery flow	kg/s	63
Delivery pressure	bar	294
Temperature of medium	°C	141
Speed	rpm	5700
Power demand	kW	2600

Table 7.1.2-14: Materials Main Feedwater Pump Sets

Housing	G-X12Cr14
Impeller	G-X12Cr14

Shaft	X-20Cr13
Sealing rings	G-X170Cr18

Main Condensate Pump Unit

Construction

- Vertical, three-stage sectional centrifugal pump, suspended in condensate tank, first stage double-flow, second and third stages single-flow
- Axial thrust compensation in second and third stages by means of gap rings and relief bores in the impeller
- Overhead axial bearing designed as tilting-pad bearing, with oil lubrication
- Upper shaft mounting in oil-lubricated friction bearing, lower shaft mounting in water-lubricated friction bearing
- Stuffing box packing with sealing water connection as shaft seal
- Replaceable protective shaft sleeves in the vicinity of the shaft seal and the lower guide bearing
- Motor support bracket
- Foundation frame
- Three-phase squirrel-cage motor
- Water-cooled
- Flexible coupling

Table 7.1.2-15: Design Data Main Condensate Pump Unit

Operating value per pump	**Unit**	
Redundancy	-	2 x 100 %
Medium	-	Condensate
Delivery flow	kg/s	193
Delivery head	m	250
Temperature of medium	°C	43
Speed	rpm	1480
Efficiency	%	78

Operating value per pump	Unit	
Power demand at the shaft, normal	kW	600
Power demand in one pump mode, maximum	kW	700

Table 7.1.2-16: Materials Main Condensate Pump Unit

Housing	GS-C 25
Impeller	G-X12Cr14
Shaft	X-20Cr13
Protective shaft sleeve	X40Cr13
Condensate tank	St 37-2

Collected Condensate Pump Unit

Construction

- Vertical, three-stage sectional centrifugal pump
- Suspended in condensate tank
- Axial thrust compensation by means of gap rings and relief bores in the impeller
- Overhead, oil-sump-lubricated rolling bearing
- Additional water-lubricated guide bearings on both sides of the impeller
- Motor support bracket
- Foundation frame
- Three-phase squirrel-cage motor
- Flexible coupling

7.2 Turboset

Component List

- Turbine
    - HP, IP, LP turbine
    - Turbine accessories

        - Oil supply
        - Drains
        - Sealing and leakage steam systems
        - Extraction valves
    - Additional devices
        - Moisture separator between IP and LP turbine sections
- Generator
    - Generator
    - Static converter exciter
    - Generator accessories
        - Gas systems
        - Sealing oil system
        - Cooling water equipment for stator winding and stator core
- Condenser
    - Condenser
    - Condensing system accessories
        - Evacuation equipment from water-ring pump with upstream gas ejector for start-up, water-ring pumps with upstream gas ejector for Operation

Requirements

Faults in the steam turbine system affect only the turboset and the associated auxiliary and supply systems. System components of importance in safety-engineering terms are, thus, not impaired in their function.

Steam Turbine

The steam turbine is a three-casing single-shaft model designed for operation with superheated steam. It consists of a HP turbine section, a IP turbine section, and a LP turbine section.

Since the exhaust steam of the HP turbine section is not reheated, a mechanical high-speed moisture separator is installed between the IP turbine section and the LP turbine section. The water content at the last stage of the LP turbine is 15 %.

The live steam is fed in by two combined stop/regulating admission valves. The turbine bypass assembly consists of two combined stop/regulating valves followed by a water injection chamber. They are dimensioned for 100 % of the live steam flow at rated load.

HP Turbine Section

The HP turbine section consists of rotor and outer and inner casings. Both casings have simple cylindrical shapes and are horizontally split at the level of the turbine axis. The live steam flows through the outer casing via thermally elastic pipe connections, and into the inner casing to the blading. To protect the rotor against severe steam forces and high temperatures, the first row of fixed blades is built into the inlet ring. In the single flow of the HP blading, the thermal energy of the steam is converted into mechanical energy and transmitted to the rotor.

The highly stressed inner casing halves are held together by sturdy shrink rings. The shrink ring design used permits the use of completely rotationally symmetrical inner casings, which are axially mounted in the outer casing at the level of steam inflow at the height of the casing joint. The inner casing is also supported at the height of the casing joint by shims in the outer casing. Lateral positioning is effected by centering bolts in the lower half of the casing, allowing adjustment to be made from the outside.

Axial shaft seals at the rotor penetrations prevent steam leakages, The residual axial thrust of the HP and IP blading is absorbed by the balance piston and the thrust bearing.

The seals for shaft and balance piston are in spring-backed labyrinth design, in order to prevent rubbing.

IP Turbine Section

The main components of the IP turbine section are rotor, inner casing and outer casing.

The steam passes from the outer casing via thermally elastic steam penetrations into the single-flow deflection ring installed in the inner casing. Cooling steam is fed through this deflection ring in order to reduce the temperature in the rotor area, and ensure that stresses are at a permissible level. In the single flow of the blading, the thermal energy of the steam is converted into mechanical energy, and transmitted to the rotor. The steam passes via an annular deflection diffusor to the exhaust steam outlet.

The outer casing is split horizontally at axis level, and is fitted with sturdy joint flanges. In order to ensure clearly defined force conditions and good sealing qualities, the lower flange incorporates sealing and support strips. The top and bottom of the outer casing are connected by hot-tightened anti-fatigue bolts. The outer casing contains the supply and exhaust steam connections, plus the connection fitting for steam extraction to preheat the feedwater.

The inner casing is likewise split horizontally at the level of the turbine axis, and fitted with joint flanges, which are held together by anti-fatigue bolts. At steam inflow level, the inner casing is supported in the outer casing by shims. Lateral positioning is effected by adjustable guide bolts, located in the bottom section and accessible from outside.

The rotor is welded together from shaft disks and shaft ends. Axial shaft seals at the rotor penetrations prevent steam leakages. The seals are in labyrinth design, with radial spring-backed ring segments, in order to prevent damage due to rubbing. The axial thrust of the blading is balanced out by the balance piston of the HP turbine section.

LP Turbine Section

The main components of the standardized LP turbine section are the outer casing, the inner casing and the rotor.

The steam passes from the inflow pipe via thermally elastic steam penetrations, connected to the outer casing by compensators, into the inflow assembly of the inner casing. After the energy has been transmitted to the rotor, the steam passes via an annular diffusor into the exhaust steam space of the outer casing before it flows down into the condenser.

The outer casing is a welded construction, split at the level of the turbine axis, and bolted together at the flanges.

It stands on the foundation, resting on supports fitted laterally along the entire length of the bottom. Longitudinal positioning in relation to the bearing housing and generator is effected by keys.

The cast inner casing with its integrated blade carriers is split horizontally and supported in the outer casing. The inner casing is axially fixed in position in relation to the outer casing in the plane of one support. Shims allow free expansion of the casing in all directions.

The rotor is welded together from shaft disks and shaft ends.

Axial shaft seals at the rotor penetrations prevent steam leakages. The seals are in labyrinth design, with radial spring-backed ring segments, in order to prevent damage due to rubbing.

Generator

The generator consists of the stator housing with the stator core and the stator winding, the end shields with the shaft seals and bearings, the rotor with the forged on coupling flange on the drive side, plus the slip ring assembly at the non-drive shaft end.

Generator Housing and Core

The generator has a rigid, vibration-resistant housing. In the centre part of the housing is the stator core. The two end sections of the housing cover the stator winding overhangs, and are each fitted with two vertical coolers.

The housings are sealed at both ends with end shields, in which the hydrogen shaft seals are also located.

Terminals

The Power generated is fed out via six terminals. The generator terminals are installed in a housing, whose floor consists of non-magnetic steel in order to avoid unnecessary losses and heat-up.

Bearings

The friction bearings located in the sturdy end shields support the rotor weight, and ensure low-vibration running. The bearing shells are double-insulated, in order to prevent any shaft currents flowing. A third bearing is installed outside the slip rings, and ensures stable running of the non-drive-side shaft end.

Type of Cooling

The coolant gas is blown from both ends of the machine into the active sections by single-flow radial fans. The core is cooled with hydrogen passing through axial ducts and exiting in the centre of the front part through radial slots.

The rotor winding consists of hollow conductors, and is cooled axially from both ends, with the hydrogen likewise exiting in the centre. There are separate, parallel cooling paths for the winding overhangs.

The stator winding also contains hollow conductors, which are directly cooled with deionized water. At both ends of the winding, stainless steel headers and teflon hoses are provided for supply and return of this cooling water. The temperature level remains relatively low even at full load, resulting in small differential expansions, small stresses, and thus a very long winding lifetime.

Temperature Monitoring

Measuring points for temperature monitoring are provided in the stator winding and in the H_2 coolant gas circuit.

Stator Winding Bars and Bar Installation

The winding consists of individual bars located in open, rectangular slots distributed uniformly around the inner circumference of the core. Each winding bar is made up of a bundle of mutually insulated sub-conductors, some of which are hollow and have cooling water flowing directly through them.

Winding Overhang Support

Outside the slotted area, the bars are angled outwards and in the direction of the circumference, thus forming two conical winding overhangs.

The winding overhang is attached to the housing ends with springs via the outer rings, so that it is supported in radial and tangential directions for absorbing short-circuit forces. In axial direction, however, these springs allow movement for absorbing expansion differences between the winding and the stator.

Rotor Body

The rotor body carries the magnetic flux, and supports the exciter winding and the parts required for supplying the excitation current.

The rotor body consists of quenched and subsequently drawn alloyed steel, with very good mechanical and magnetic properties. It is forged from a cast block.

The shaft end on the drive side has a forged-on coupling flange for connecting to the turbine shaft. On both sides of the rotor body the shaft possesses seat areas for bearings, shaft seals and fans.

Rotor Cap

The rotor is fitted at both body ends with a rotor cap, which absorbs the centrifugal forces of the rotor winding overhang. The rotor cap consists of the cylindrical cap ring and the discoid cap plate.

Rotor Winding

The excitation current required in order to generate the armature field flows in the rotor winding, which consists of hollow conductors.

The conductors consist of drawn, oxygen free copper with a silver content, offering high strength and resistance to hydrogen embrittlement.

Stator Cooling Water System

The cooling water system is designed as a compact unit, and supplies the water for direct cooling of the stator winding and the terminals. All connecting pipes are made of stainless steel. The cooling circuit is an enclosed system, filled with demineralized and hydrogen-saturated water. The purity of the water is automatically monitored on a continuous basis. About 1 % of the water quantity flows continuously for regeneration purposes through ion exchangers in the bypass. The water thus treated has a very low electrical conductivity, and is free from oxygen, which is important for preventing corrosion.

The pumps and coolers are provided in a doubled-up design, i.e. with 100 % stand-by.

Hydrogen and Carbon Dioxide System

The hydrogen system maintains the pressure and the purity of the hydrogen during operation. The associated carbon dioxide system serves to flush the generator before it is filled with hydrogen during start-up.

Sealing Oil System

The vacuum sealing oil system supplies the shaft sealing rings with deaerated oil. The leak-proof seal is achieved by pumping oil into the fine gap between the rotating shaft and the stationary shaft sealing ring.

Slip rings and Brush gear

The assembly for transmitting the excitation current consist of two slip rings and brush yokes per set, the brush holders and carbon brushes.

Air-Cooled Condenser

Construction and Function

The exhaust steam of the LP turbine is condensed in an air-cooled condenser, which is located directly adjacent to the turbine hall. Two parallel exhaust steam pipes branch off from a transition piece located at the exhaust steam housing, and distribute the steam among 6 parallel-connected sub-condensers, each consisting of 6 condenser groups, each provided with cooling air by a vertically blowing fan.

The heat exchanger elements form elliptical tubes onto which rectangular fins are pushed, connected in parallel on the steam side and partly in parallel, and partly in series on the air side. On the steam and condensate side they are fitted with headers, which connect to the distribution pipes. To reduce the "dead zone", the tubes, which are arranged behind each other in the flow direction of the cooling air, are fitted with varying fin configurations, being wider at the front tubes than at the rear ones, since the cooling air warms up as it passes through the bundle, and thus the temperature differential between steam and cooling air decreases from tube row to tube row.

The tube bundles are configured in a roof shape having an angle of 60°. A support construction prevents bending and vibration. In those tube bundles connected as a parallel-flow condenser, the flow passes from top to bottom so that excess steam remains. This prevents the formation of a "dead zone", in which condensate collects and is sub-cooled. Both phenomena are unwanted, due to the blockage of usable heat exchanger surface and the formation of aggressive condensate as a result of oxygen enrichment.

In those tube bundles connected as a counter-flow condenser, the dephlegmators, the excess steam from the parallel-flow condensers enters at the bottom, and the condensate exits at the bottom. In the upper part, sub-cooled, non-condensable gases and air collect, which are extracted by the evacuation system.

The proportion of dephlegmator heat exchanger surface is about 20 %, with the condenser surface making up 80 %.

The roof-shaped sub-condensers are mounted on galvanized steel frames, which also support the vertical fans. The steel frames rest on reinforced-concrete supports. Their length is dimensioned so as to ensure that the cooling air required can flow unhindered to the fans.

The axial fans are fitted with blades made of plastic reinforced with glass fiber, with a variable angle of attack. The gear is mounted in roller bearings and lubricated with oil. Squirrel-cage electric motors are used for the drive.

Control

Taking the outside air temperature and the power plant output as given, the only controllable variable is the cooling air flow through the air condenser. It is influenced by switching the fans on and off.

The use of the fans is optimized with the aid of a cooling tower computer. For every switch step, the objective is to minimize the sum of generator output loss and fan output loss.

7.3 Start-up and Shutdown System

Component List

- Steam condenser
- Feedwater tank
- Feedwater pumps
- Pipes
- Isolation valves, safety valves
- Thermal insulation

Requirements

The start-up and shutdown system is a service system, and is not subject to any special safety-engineering requirements. It serves for start-up and shutdown of a unit, or of both units in proper operation, in the event of operational disturbances, and in the event of accidents, and for long-term decay heat removal. The technical data are listed Table 7-21.

Table 7.3-1: Technical Data of Start-up and Shutdown System

Operating value	Unit	
Live steam temperature	°C	530
Live steam pressure	bar	113
Live steam mass flow	kg/s	10.9
Feedwater temperature	°C	140
Feedwater pressure	bar	90
Redundancies	%	2 x 100
Output range per line	%	0 - 100

Function and Construction

The start-up and shutdown system consists of two identical subsystems (Figure 7.3-1), and is located in the intermediate building.

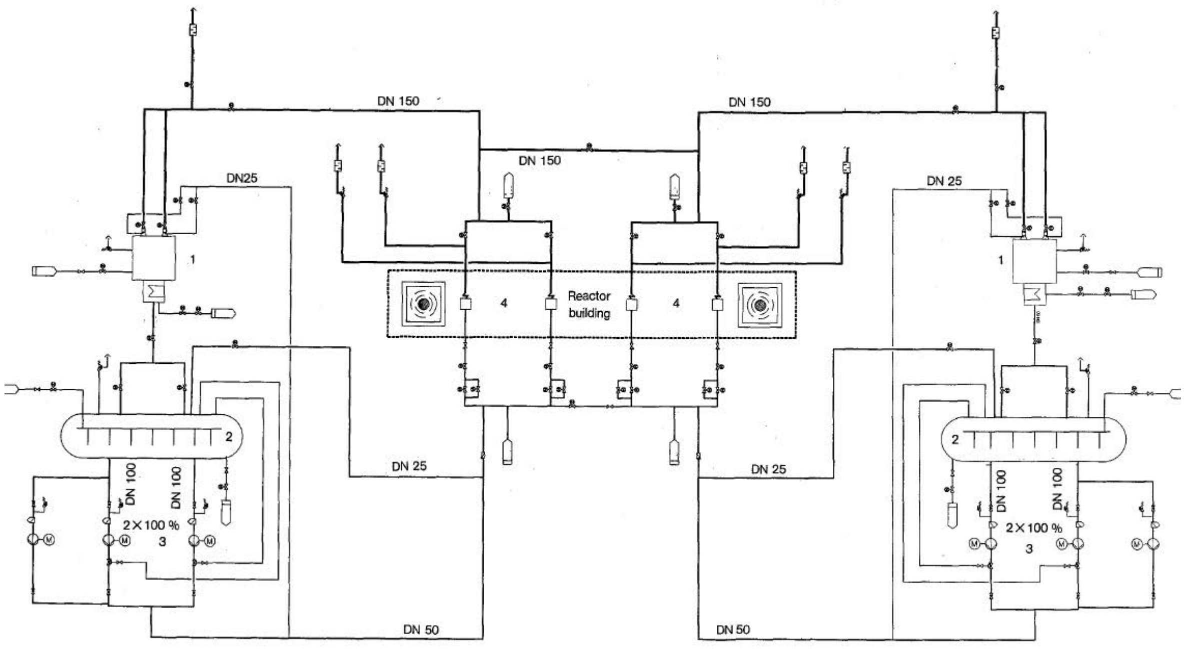

Figure 7.3-1: Start-up and Shutdown System

The lines branch off at the two steam-generator headers in the intermediate building, and lead to a steam condenser with two injection-type steam pressure reducing stations.

A stop valve is installed in this pipe, separating the start-up and shutdown system from the LS system in normal operation. This stop valve is opened for start-up and shutdown procedures and for decay heat removal.

The two lines of the start-up and shutdown system are connected to each other via a connecting pipe, so that if one line fails the other line can be connected to the same LS line, and thus to the same reactor. A corresponding connecting pipe is provided on the condensate side.

In the steam condenser, the wet steam is condensed and cooled in closed circuit. Closed-circuit cooling is performed by the component cooling water system.

The condensate flows into the start-up and shutdown collecting tank.

Two 100 % start-up and shutdown pumps pass the condensate into the feedwater header, thus closing the start-up and shutdown circuit. The pumps are supplied with guaranteed service power.

During proper operation, the steam condenser and the start-up and shutdown collecting tank are kept warm by the auxiliary steam line. The pipes from the start-up and shutdown tank to the feedwater header are likewise kept warm with a circulation pump during proper operation.

8 Cooling Water Systems

8.1 Component Cooling Water System

Component List

- Intermediate coolers
- Compensation tanks
- Partial flow filters
- Component cooling water pump sets
- Pipes, valves

Requirements

The component cooling water systems are not significant in safety-engineering terms, and are accordingly not designed against the effects of external events. In the event of a power failure, electricity will be supplied by the guaranteed service power diesel generating sets, due to availability considerations.

Maintenance, testing or repair of a pump or heat exchanger do not require the reactor to be shut down.

The requirements for materials, calculations, design, manufacture, erection, including the associated testing, comply with the conventional body of rules.

Dimensioning

Dimensioning is based on loads from operating internal pressure, dead weight and thermal expansion figures in accordance with the conventional body of rules.

Function and Construction

Component Cooling Water Systems

The component cooling water systems are component cooling water circuits, which in the intermediate coolers transfer the heat produced in the component coolers to the corresponding secondary cooling water system. The intermediate coolers are dimensioned for 2 x 100 % output, and the component cooling water pumps for 2 x 100 %, so as to ensure the requisite availability of the heat removal function. A compensation tank is provided to even out fluctuations in volume. Its nitrogen cushion prevents any oxygen penetrating into the circuit. The pH value of the component cooling water, which consists of condensate, is adjusted by dosing in ammonia. Mechanical filters are provided for cleaning a partial flow.

In the event of fluctuations in the temperature of the secondary cooling water, the temperature of the heat dissipating media is regulated not by the cold water temperature of the component cooling circuits, but by bypassing the associated component cooler on the heat emitting side.

Coolers and pumps of the primary component cooling water circuits are located in the reactor auxiliary building, those of the secondary component cooling water circuit in the turbine hall, and those of the guaranteed service power diesel generating sets in the switchgear and control building.

Primary Component Cooling Water System

Each reactor possesses a primary component cooling water system, which removes the heat from the following components:

- Cooler of the concrete cooling system
- Coolant gas circulator*
- Circulator of the fuel element charging system
- Gas purification system
- Air recirculation system in the spent fuel element storage building*
- Chilled water sets for the ventilation systems for reactor building and reactor auxiliary building*
- Helium compressor of the purified-gas system*
- Liquid waste system*

50 % of the consumers marked with an * are supplied by the component cooling water system of the other reactor, for reasons of availability. The coolers of the concrete cooling system can be switched over by hand to the primary closed cooling water system of the other reactor.

Technical Data

Operating mode		Normal and DHR mode	Reactor 1 normal Reactor 2 disturbed
Thermal output	MJ/s	4.5	6.2
Cold water temperature	°C	30.0	30.0
Warm water temperature	°C	34.3	36.0
Cooling water mass flow	kg/s	250	250

Secondary Component Cooling Water System

The secondary component cooling water system serves to cool the following components:

- Coolers for the generator of the turboset

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- Bearing oil and control fluid coolers of the turboset
- Water-ring pumps
- Main condensate and collected condensate pumps
- Compressed air compressor
- Chilled water sets of the ventilation systems in the switchgear and control building
- Sampling coolers of the secondary water/steam circuit

The system can be connected to the secondary cooling water system of either Reactor 1 or Reactor 2 as desired.

Technical Data

Operating mode		Normal mode
Thermal output	MJ/s	8.6
Cold water temperature	°C	30
Warm water temperature	°C	36
Cooling water mass flow	kg/s	340

Component Cooling Water System for the Guaranteed Service Power Diesel Generating Sets

This system removes the heat present in the charging air, the cooling water and the lubricating oil of the diesel engines, and in the cooling air of the generators.

Technical Data

Operating mode		Normal mode
Thermal output	MJ/s	1.0
Cold water temperature	°C	30
Warm water temperature	°C	36
Cooling water mass flow	kg/s	40

8.2 Service Cooling Water System

Component List

- Cooling tower
- Service cooling water pump sets

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- Pipes, valves

Requirements

The service cooling water system is not significant in safety engineering terms, and for this reason is not designed against the effects of external events. In the event of a power failure, electricity will be supplied by the guaranteed service power diesel generating sets, due to availability considerations.

Maintenance, testing or repair of a pump or cooling tower does not require the reactor to be shut down.

The requirements for materials, calculations, design, manufacture and erection, including the associated testing, comply with the conventional body of rules.

Dimensioning

Dimensioning is based on loads from operating internal pressure, dead weight and thermal expansion figures in accordance with the conventional body of rules.

Function and Construction

System Description

Each reactor is equipped with its own service cooling water system, which removes the heat from the coolers listed below and passes it to the surrounding air via a cellular-design wet cooling tower with forced air cooling

- Intermediate coolers for the primary component cooling water system
- Intermediate coolers for the guaranteed service power diesel generating sets
- Condensers for the start-up and shutdown system of the water/steam circuit
- Intermediate coolers for the secondary component cooling water system

In order to limit the cooling water mass flow, and to attain high water temperatures, the coolers in the various component cooling circuits are connected in series to the condenser of the start-up circuits. The intermediate coolers of the secondary component cooling water system are normally assigned to service cooling water system 2. If this service cooling water system fails, they are switched over to service cooling water system 1, so that the turbine is not affected.

The intermediate coolers of the concrete cooling system, plus half of the helium gas circulator coolers, can be connected either to primary component cooling water system 1 or 2, and can thus be cooled by either of the service cooling water systems.

Each of the two service cooling water systems consists of an open circuit with 2 x 100 % service cooling water pumps, pipes, valves, cleaning equipment for the intermediate coolers, and a wet cooling tower with two cells. The service cooling water pumps are located in pump rooms, which are directly adjacent to the cooling tower basin.

The cold water temperature for service cooling water is manually adjusted by selecting the number of cooling tower cells required and the operating mode of the cooling tower fans to suit the amount of heat and the ambient conditions concerned.

The blowdown water from the cooling towers is passed to the recipient either directly or via a neutralizing pond. The service cooling water consists of mechanically cleaned and (if necessary) mechanically treated fresh water. Spray, evaporation and blowdown losses in the cooling towers are replaced by treated cooling tower make-up water, which should be decarbonised and should also contain the chemical agents required to prevent biological growth.

Technical Data

Operating mode		Normal operation	DHR operation
Thermal output	MJ/s	14.1	27.1
Cold water temperature	°C	30	30
Warm water temperature	°C	35.3	40.5
Cooling water mass flow	kg/s	630	630

9 Electrical Systems

9.1 Total System

Component List

The electrical system consists on the following components:

- Outgoing Power Transmission
  - Generator leads
  - Generator circuit breaker
  - Compressed air system

- Auxiliary Power Systems
  - kV unit switchgear installations, including automatic quick change-over unit
  - 660 V - unit/station switchgear installations
  - 380 V - unit/station switchgear installations
  - 660 V - emergency power switchgear installations

- D.C. Supplies
  - 220 V d.c. switchgear installations, including batteries, rectifiers
  - 24 V d.c. switchgear installations, including batteries, rectifiers

- Transformers
  - Unit transformer with control cubicle and oil/air cooling system
  - Unit auxiliary transformer
  - Outside system transformer
  - L.V. transformers
    - Three-winding oil-immersed transformers
    - Two-winding oil-immersed transformers

- Drives, Units
  - Inverters for coolant gas circulator power supply
  - 10 kV guaranteed service power diesel generator sets
  - 0.7 kV emergency power diesel generator sets for battery charging

  - Inverters for DHR circulators

- Protection
  - Unit protection, including synchronization
  - Protection for 10 kV diesel generator sets
  - Protection for 0.7 kV diesel generator sets
  - Protection for circulator inverters
  - Protection for outside-system transformers

- Cables and Power Lines
  - Cables with all accessories required for cabling, for consumers of the power plant and for sub-distributions in the buildings planned by the owner
  - Power sockets in buildings of the power plant

- Ancillary and Communication Systems
  - Interior lighting in the buildings, excluding those planned by the owner
  - Exterior lighting (excluding intrusion-protection-system lighting)
  - Obstacle lighting an vent stack
  - Internal grounding of the buildings, as above
  - External grounding
  - Lightning protection for buildings as above
  - Fire alarm system for buildings as above
  - Communication systems
    - Telephone private branch exchange
    - Personnel paging system
    - Control room telephone system
    - Alarm system
    - Radiotelephone system

Task Definition

The task of the electrical systems is to:

- feed the power generated by the generator into the national power network

- distribute the power required for station service inside the power , plant
- supply electricity to the process-engineering consumers required both for operating the power plant and for coping with accidents.

Overview

The power supply concept is shown in the single-line diagram, Figure 9.1-1.

The station power supply is divided into the service power supply, the guaranteed service power supply, and the emergency power supply systems.

The station power is supplied by the generator or the national power network. Assignment of the process-engineering systems to service, auxiliary and emergency power supply systems is shown in Table 9.1-1.

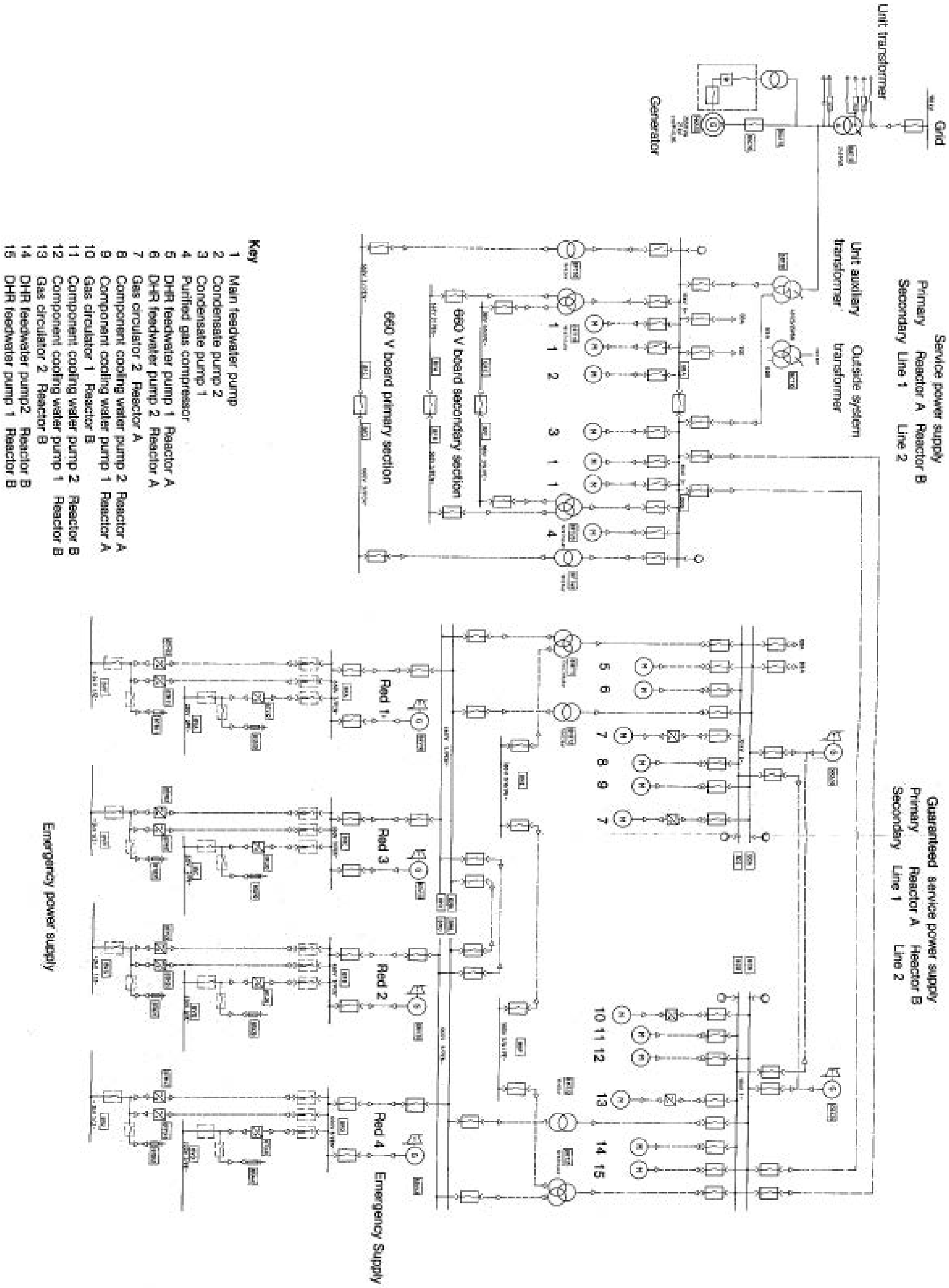

Figure 9.1-1: Station, Emergency / Service Power Supply System

Table 9.1-1: Assignment of Process Systems to Power Supply Systems

System	Service Power	Guaranteed service power	Emergency Power
Reflector rods		x	
Small absorber pebbles			x
Coolant gas circulators (incl. magnetic bearings)		x	
Refuelling system	x		
Feedwater system	x		
Live steam system		x	
Start-up + shutdown systems		x	
Component cooling water system		x	
Service cooling water system, primary		x	
Service cooling water system, secondary	x		
Concrete cooling system		x	
Condensate system	x		
Deionized water system	x		
Plant effluent disposal system	x		
Condensate clean-up system	x		
Auxiliary steam system	x		
Dosing system	x		
Active liquid waste treatment system	x		
Turboset	x		
Gas secondary circuits	x		

System	Service Power	Guaranteed service power	Emergency Power
Exclusion area ventilation	x		
Intermed. building ventilation	x		
Turbine hall ventilation	x		
Switchgear building ventilation		x[1)]	
FE store ventilation		x[2)]	
Instrumentation + control systems			x
Activity monitoring			x
Penetration isolating system			x

1) only in the part relevant for accident handling

2) with special measures in the event of internal or external events

Service Power Supply

The service power supply is in two-line structure. One line supplies:

- All consumers of a reactor belonging to the service system
- For multi-line service systems not assigned to a reactor, the consumers of one line
- For single-line service systems not assigned to a reactor, the consumers of this system

This ensures that in the event of disturbances in the service power supply

- only the service system of one reactor is affected and
- in the case of multi-line service systems not assigned to a reactor, one line will remain available.

The service power supply is divided into the following voltage levels:

- 10 kV voltage level, in each case fed from the assigned turbo-type generator via the unit auxiliary transformer or from the national power network via the outside system transformer
- 660 V voltage level, via l.v. 10/0.7 kV transformers
- 380 V voltage level, via l.v. 10/0.4 kV transformers

Guaranteed Service Power Supply

The guaranteed service power supply is also designed with a two-line structure. Assignment of the systems to the power supply follows the same scheme as with the service power supply. In the event of a mains failure, the busbars of the guaranteed service power supply are supplied via 10 kV diesel generating sets. The circuit has been selected so as to ensure that in the event of one diesel generating set failing, at least one circulator and one process-engineering component can always be operated for decay heat removal per reactor.

The following voltage levels are available for the guaranteed service power supply:

- 10 kV fed from the service power supply or the diesel generating sets
- 660 V voltage level, via l.v. 10/0.7 kV transformers
- 380 V voltage level via l.v. 10/0.4 kV transformers.

Emergency Power Supply

The emergency power supply is in four-line redundant structure; it is important in safety-engineering terms, and its design complies with the requirements of the KTA body of specifications. In the event of the feed from the guaranteed service power supply failing, the busbars of the emergency power supply are supplied via individually assigned 0.7 kV emergency diesel generating sets. These sets are dimensioned so as to ensure that the entire control systems can be supplied in addition to the reactor protection system.

The following voltages are provided for the emergency power supply:

- 660 V from the guaranteed service power supply and the 0.7 kV diesel generating sets
- 220 V and +24 V d.c., battery-backed.

Operating Modes

The power plant is started up using the national power network, with the generator breaker open. If only one reactor is being started up (second reactor in operation), this does not affect the switching operations of the auxiliary power supply. In load mode, power is fed from the generator via the generator breaker into the national power network. The voltage is regulated by the generator voltage regulator.

Shutdown and Subsequent Standstill

Normal shutdown of the power plant utilizes the national power network. Shutdown of one reactor does not affect the switching operations of the auxiliary power supply.

Failure of the National Power Network

Feed into the national power network is opened. The generator covers the auxiliary power demand.

Turbine Tripout

In the event of turbine tripout and available national power network, the generator breaker opens; auxiliary power supply is taken from the national power network.

If the outside power network also fails, then all diesels are started up at the 10 kV guaranteed service power busbars. Once the diesels have run up to speed, they take over the guaranteed service power and emergency power supply functions.

Generator Failure

The switching operations are analogous to those for turbine tripout.

Failure of the Unit Transformer or the Unit Auxiliary Transformer

The generator breaker and the h.v. side breaker of the unit transformer open. The disturbance results in excitation of the fast change-over device of the 10 kV switchgear installations. Power supply comes via the outside system transformer.

Failure of a 10 kV Service Switchgear Installation (Short-Circuit)

The consumers previously supplied through the disturbed 10 kV switchgear installation are shut down by the undervoltage time protection feature. The following units remain under voltage:

- The non-disturbed 10 kV service switchgear installation, including the downstream guaranteed service and emergency switchgear installations
- The l.v. switchgear installations of the service power supply systems (through automatic change-over of the coupled breakers)
- The guaranteed service and emergency power supply supplied by the failed switchgear Installation is taken over by the diesels

Failure of a 10 kV Guaranteed Service Power Switchgear Installation (Short-Circuit)

The consumers previously supplied through the disturbed 10 kV switchgear Installation are shut down by the undervoltage time protection feature. The downstream l.v. switchgear installations can be started up again by closing the coupled breaker. Emergency power supply is taken over by the 0.7 kV emergency diesel generating sets.

Failure in the Area of the L.V. Service Power Supply

If an l.v. transformer fails, the coupled breaker is used to make a connection between the de-energized 660 V or 380 V half-busbar and the half-busbar remaining under voltage. This change-over is an automatic function (feeder circuit-breaker - OFF, coupled breaker - ON).

If an l.v. service switchgear installation fails (short-circuit), the l.v. consumers supplied from the disturbed and failed l.v. switchgear Installation can no longer be supplied.

Failure in the Area of the L.V. Guaranteed Power Supply

If an l.v. transformer fails, the coupled breaker can be used to make a connection between the de-energized 660 V or 380 V half-busbar and the half-busbar remaining under voltage. The change-over is made by hand. The diesel at the de-energized emergency power system starts up and takes over the supply function.

If an l.v. guaranteed service power switchgear installation fails, the consumers supplied from the disturbed and failed switchgear installation can no longer be supplied. The diesel at the downstream emergency switchgear Installation starts up and takes over the supply function.

Failure of a L.V. Emergency Switchgear Installation

The l.v. consumers supplied from the disturbed and failed switchgear installation can no longer be supplied.

Failure of the 220 V D.C. Supply

The 220 V d.c. systems are in four-line design, with each line consisting of a rectifier, a battery and a 220 V d.c. switchgear Installation.

If the 660 V three-phase supply fails, the batteries supply the consumers connected. Even if the charger fails, the consumers continue to be supplied from the batteries.

If a 220 V switchgear Installation fails (e.g. short-circuit), the diode-decoupled-supply consumers continue to be supplied from the second 220 V switchgear installation.

Failure of the +24 V D.C. Supply

The +24 V d.c. systems are in four-line design, with each line consisting of two rectifiers, a battery, and a +24 V switchgear Installation.

If the 660 V three-phase supply fails, the batteries supply the consumers connected. Even if the chargers fail, the consumers continue to be supplied from the batteries.

If a +24 V switchgear installation fails (e.g. short-circuit), the diode-decoupled-supply consumers continue to be supplied from the second +24 V switchgear installation.

Failure of Service and Guaranteed Service Power Supply

If the service and guaranteed service switchgear installations are destroyed, the emergency power supply is taken over by the 0.7 kV diesels. The 660 V emergency power busbars are de-energized while the diesels are running up. The 220 V and +24 V d.c. switchgear installations remain under voltage without interruption, thanks to the battery guaranteed service.

9.2 Generator Leads

Construction

Single-phase encapsulated heavy-current leads with self-cooling feature.

Technical Data

The technical data are shown in Table 9.2-1.

Table 9.2-1: Technical Data Generator Leads

Generator Lead		
Rated voltage	kV	21
Rated insulation voltage	kV	30
Rated current	kA	6.5
	kA	7.0
Surface temperature of encapsulation	-	to ANSI
Generator Circuit-Breaker		
Rated voltage	kV	21
Rated current	kA	8

9.3 Auxiliary Power Systems

Construction

- Medium-Voltage Switchgear Installations:
  Steel-plate-encapsulated, partitioned switching bays with withdrawable switchgear truck and three-pole circuit-breakers
- L.V. Switchgear Installations:
  Modular-structure cubicle system with withdrawable drawer units and fixed non-drawout assemblies

Technical Data

The technical data are shown in Table 9.3-1 for 10 kV Unit switchgear installation and for the L.V. switchgear installation respectively.

Table 9.3-1: Technical Data Auxiliary Power Systems

10 kV Unit Switchgear Installation		
Rated voltage	kV	10
Rated breaking current	kA	43
tested in accordance with	-	PEHLA
Number of bays	-	43
L.V. Switchgear Installation, Service, Guaranteed Service and Emergency Power		
Rated voltages	kV	0.66
	kV	0.4
	V d.c.	220
	V d.c.	+24
Number of bays	-	167

9.4 D.C. Supplies

Construction

- Rectifiers:
  Thyristors with non-controlled silicon cells
- Batteries:
  Lead batteries with cell containers of transparent plastic
- Inverters:
  Static inverters featuring electronic change-over option to the associated emergency power distribution

Technical Data

The technical data for D.C. supplies are shown in Table 9.4-1.

Table 9.4-1: Technical Data D.C. Supplies

220 V		
Batteries:		
Number	-	4
Cells	each	108
Plates	-	lead
Construction	-	Gro E
Capacity at 10 h discharge	Ah	1 000
Discharge time	min	30
Rectifiers:		
Number	-	4
Rated voltage	V	240
Rated current	A	1 000
Charging characteristic	-	CVCC/manual charging
+24 V		
Batteries:		
Number	-	4
Cells	each	13

Plates	-	lead
Construction	-	Gro E
Capacity at 10 h discharge	Ah	2000
Discharge time	min	30
Rectifiers:		
Number	-	8
Rated voltage	V	29
Rated current	A	1600
Charging characteristic	-	CVCC/manual charging

9.5 Transformers

- Unit Transformer:
  Three-phase single-tank transformer with built-on oil/air coolers and neutral-end tap-changer
- Unit Auxiliary Transformer:
  Three-phase single-tank transformer with built-on oil-air coolers and reconnect-able off-circuit tap-changer
- Outside System Transformer:
  Three-phase single-tank transformer with built-on oil/air coolers and neutral-end tap-changer
- L.V. Transformers:
  Three-winding oil-immersed transformers and two-winding oil-immersed trans-formers

Technical Data

The technical data of the transformers are shown in Table 9.5-1.

Table 9.5-1: Technical Data Transformers

Unit Transformer		
Number	-	1
Rating	MVA	240
Voltage	kV	160 ± 11 % / 21
Short-circuit voltage V_K	%	14

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Unit Auxiliary Transformer		
Number	-	1
Rating	MVA	40/25/25
Voltage	kV	21 ± 5% / 10.8
Outside System Transformer		
Number	-	1
Rating	MVA	40/25/25
Voltage	kV	160 ± 11 % / 10.8
Low-Voltage Transformers three-winding		
Number and Rating	MVA	2 at 5.5
	MVA	2 at 2.5
Voltage	kV	10/0.7/0.4
Low-Voltage Transformers two-winding		
Number and Rating	MVA	2 at 2
	MVA	2 at 1
Voltage	kV	10/0.7

9.6 Drives, Machines, Diesel Generating Sets

9.6.1 Diesel Generating Sets

Construction

- 10 kV Sets:
  - 16-cylinder 4-stroke diesel engine with exhaust-gas turbo-charging and charging-air cooling. The heat losses from the motor are removed by the component cooling water system
  - Three-phase synchronous generator, three-phase exciter and rotating rectifier bridge

Design and manufacture is in accordance with the conventional body of standards.

- 0.7 kV Sets:
  - 6-cylinder 4-stroke diesel engine with exhaust-gas turbo-charging and charging-air cooling. Heat losses from the motor are dissipated into the surrounding air
  - Self-regulating three-phase synchronous generator in brushless design

Design and manufacture is in accordance with the conventional body of standards.

Technical Data

The technical data for the diesel generating sets are shown in Table 9.6.1-1.

Table 9.6.1-1: Technical Data Diesel Generating Sets

10 kV Sets		
Number	-	2
Diesel engines:		
Continuous rating to DIN 6280	kW	5700
Speed in rpm	min^{-1}	1500
Generators:		
Rating	kVA	6000
Voltage	kV	10
Protection Class	-	IP 23
Insulation Class	-	F, tending to B
Starting	-	compressed air
Load transfer after start release	s	12
Fuel storage tank:		
per set	m^3	100
0.7 kV Sets		
Number	-	4
Diesel engines:		
Continuous rating to DIN 6280	kW	270
Speed in rpm	min^{-1}	1500

Generators:		
Rating	kVA	260
Voltage	V	660
Protection Class	-	IP 23
Starting	-	electric
Fuel storage tank:		
per set	m^3	6

Design and manufacture in accordance with the body of standards for nuclear power plants.

9.6.2 Static Inverters for Coolant Gas Circulators

Construction

Static current-source inverters are working on the injected current principle, for feeding the variable-speed asynchronous squirrel-cage motors.

Technical Data

The technical data of the inverters are shown in Table 9.6.2-1.

Table 9.6.2-1: Technical Data Inverters for Coolant Gas Circulators

Inverters		
Number	-	4
Rated output	kVA	2300
Output voltage	kV	max. 3
Control range	%	10-100

9.7 Protection

Construction

- Electronic protective relays in compact design
- Synchronising feature, twin-channel, with voltage matcher

9.8 Cables and Power Lines

Construction

- PVC cables
- Halogen-free cables are used for locations demanding thermal stability and resistance to radiation.

Technical Data

The technical data for the transformers are shown in Table 9.8-1.

Table 9.8-1: Technical Data Cables and Power Lines

Heavy-current cables		
Lenght	km	305
Main cable routes		
Lenght	km	6

9.9 Ancillary and Communication Systems

Construction

<u>Lighting:</u>

- General lighting
- Emergency lighting
- Escape route lighting
- Outside lighting
- Obstacle lighting
- Emergency power socket network

<u>Fire Alarm System:</u>

- Modular central station with its own power supply and individual signalling lines.

<u>Grounding System:</u>

- Mesh network below buildings.

- Annular network to connect the buildings on the power plant site.

Lightning Protection:

- Expanded scope, in conformity with VDE 0185, Parts 1 & 2, and with KTA 2206. Lightning conductors mainly concreted.

10 Control Systems

10.1 Total System

Component List

Primary Section

- Equipment for the measuring functions, and for binary and analogue control for all primary process systems. Control valves and drives are incorporated in the system.
- Equipment for safety systems, such as triggering system for safety devices and reactor shutdown, decay heat removal systems
- Radiation monitoring system, local dose rate monitoring system
- Seismic instrumentation
- Reactor-specific measuring equipment
- Control room with desk and Panels, local control stands, emergency control point
- Process computer system with alarm annunciation
- Unit output control system
- Conventional alarm annunciator system
- Cabling, sub-distributors, signal distributors

Secondary Section

- Equipment for instrumentation and control of all secondary process systems, including regulating valves and motor-driven actuators. The control technology for the service systems, such as the condensate clean-up system and the demineralization system, is included in the scope of delivery of the system concerned.
- Appropriate proportion in desk and panels, local control stands
- Conventional alarm annunciator system
- Cabling, sub-distributors, signal distributors

Technical Data

- Instrumentation and Control

  Cubicles 20

  - Auxiliary control room
  - Emergency control points

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Measuring Circuits (Pressure, level, temperature etc.)	2 500

• Disturbance and Alarm Signals	2 000
Cubicles	37
○ Auxiliary control room	
○ Emergency control points	
○ Turboset and air-cooled condenser	
Drive controls	1 170
Function group automatic systems	100
Shutdown chains in reactor protection quality	24
• Analogue Control	
Analogue control loops	85
• Control desk	
Operating modules	225
Annunciation modules	100
• Process Operator Station	
Detail displays	1 100
• Cables	
Main cables	300 km

Requirements

The control systems are classified into the following three categories, depending on the requirements involved:

- Category 1 includes the control equipment which in conjunction with active components serves for accident handling, detection and monitoring. Apart from the conventional requirements from guidelines and safety rules, they are also designed to comply with the nuclear codes and standards.

The equipment in this category must be protected against internal or external events, either by design measures, housing or geographical separation, so as to ensure that a single event at the location concerned results in the failure of only one redundant system at the most.

Note that the control systems are thus designed to withstand earthquakes. Consequential damage from other components not designed in accordance with this requirement has been taken into consideration. Equipment in this category must thus be accommodated in the reactor building and the switchgear building.

The following design conditions apply in the reactor building: ambient temperature globally below 100 °C, provided the individual redundant systems are distributed symmetrically in the reactor building . If this condition cannot be fulfilled, the components must be designed for use in temperatures below 260 °C, depending on the location concerned. The ambient pressure is max. 1.1 bar, the relative humidity is 100 % at 50 °C.

The equipment must be installed so as to allow replacement. The repair times are up to 100 h for mechanical system parts, and up to 10 h for electrical parts. This does not apply to the system parts installed in the RPV. The number of separate cable routes corresponds to the number of redundant systems.

- Category 2 comprises the control equipment serving for the protection of high-value assets like components, and machinery protection or the protection of safety equipment.

  This equipment is designed to comply with the specifications of the conventional body of standards. Measuring is in single-redundant design. Diversity is necessary only when the protection objective cannot be achieved with one measured variable, in which case a non-redundant design is used. A higher degree of redundancy is to be provided only in individual cases where especially stringent requirements in regard to reliability and non-availability apply.

  The control equipment in this category is designed to withstand internal and external events at the corresponding location only if the process components in question are needed to handle the internal or external event concerned, or must be protected against consequential damage.

  Cables for this equipment are laid on the same routes as those for the Category 1 equipment, if the cables are of equivalent design for withstanding internal events. Redundant cables must be laid on separate routes.

- Category 3 comprises the control equipment for the service systems. The degree of redundancy depends on the process components concerned. They are in non-redundant design. They are designed for the external ambient conditions found in normal operation, i.e. in the reactor building:

for temperatures	- below 50 °C for function
	- below 70 °C without function
for pressures	- below 1.1 bar

for relative humidity - below 60 % at 50 °C.

They are completely decoupled from the equipment of Category 1. It is permissible to lay all cables for this category on one route. This equipment conforms to the specifications of the conventional body of standards. Design features or protection against internal or external events are incorporated only with regard to fire-protection measures.

Basic Design Considerations

Function and Degree of Automation

The twin unit power plant is used for power generation essentially in base-load and medium-load operation. Participation in frequency back-up control is provided. The control range lies between 50 and 100 % of rated load, with the load change speed (steady) being maximal between 5 and 10 % of rated load per minute, depending on the change amplitude. The system is designed to enable the operating staff to cope with the following operational disturbances:

- Load-shedding in auxiliary power mode
- Turbine tripout with bypass mode
- Failure of a feed water pump
- Failure of a primary gas circulator
- Failure of a steam generator line

For the work to be performed in the control room, 2 control operators and 1 unit foreman are sufficient in all operating phases.

On the basis of the conditions listed above, the system planned is automated essentially on 2 levels, i.e. both the drive control level (individual control level) and also the group control level are implemented both in the binary control system and in the analogue control system.

The analogue control functions are located on the process control level, to provide automatic interaction between reactor steam generation and power generation within the control range.

Functions during Operation

Start-up preparations for the unit must be performed by hand.

During power mode, alterations in parameters are largely effected by the analogue control. The binary control performs the task of switching on and off the requisite additional machinery or stand-by sets in accordance with the requirements involved.

If during operation disturbances occur in the power plant system or the control system, the task of the control system is to transpose the entire power plant system automatically into a safe operating state.

Unit shutdown is performed almost entirely automatically, using the function-group control. During unit standstill, the control system performs monitoring tasks (messages/displays).

The control system has been conceived to allow the requisite tests and regular in-service inspections to be performed on the process components.

Safety and Availability

- Safety of the Control System

The requirements for control system safety must be derived from the protection tasks performed by the control system:

  - Protection of humans and the environment
  - Protection of the power plant and the large components
  - Protection of the machinery

The control systems used must comply with the safety requirements listed below:

  - Use of type-tested devices in accordance nuclear rules for functions of the reactor protection System
  - Two-key operation
  - Monitoring of binary transmitters with protective functions for broken wires
  - Monitoring of analogue signal detection for signal limits and disturbances in the voltage supply
  - Monitoring important analogue measurements, using channel comparison
  - Use of selector modules ("a" from "n") for increased safety
  - Connection between protective loop and triggering device to be as direct as possible
  - The reactor protection system is structured to be independent function wise in relation to the service system
  - Triggering signals from the reactor protection system have priority over service system signals
  - Active interlocking (protection OFF or ON) has priority over other inputs
  - Within the analogue control system, the following essential features are provided:
    - Priority circuit for manual interventions

- Mandatory manual switching and signalling of same in the event of failure of measured values involved in analogue control

- Availability of the Control System

The availability of the control system is determined by the device technology used, the circuit structure, the system structure and the power supply.

A large part of the safety-enhancing measures listed above also have a positive effect on system availability.

In addition, the following points apply:

- Within the structure of the binary and analogue control systems, fault detection and fault localization functions are incorporated for rapid correction of disturbances
- Selective protection of the individual electronic components
- The protection control and protection interlocks for machinery remain functional when the function group control is switched off

Redundancy and Independence

Structure and configuration of the reactor protection system comply with the body of nuclear codes and standards.

The control equipment of the auxiliary systems for decay heat removal are also structured and configured in conformity with the nuclear codes and standards, in order to achieve the high degree of availability required.

Operation and Monitoring

The Twin Unit HTR Power Plant is operated from the permanently manned unit control room. The control room equipment (desk, panels, etc.) contains all elements required for operation of and information on the ongoing power plant process, and allow implementation of all measures influencing the power plant processes, evaluation of regular in-service inspections, detection of disturbances and accidents, and assessment of the operability of the electrical and control systems.

Information which is not required for power plant control is displayed in the auxiliary control room (e.g. fire alarm system, printers for data logger system).

The process computer installed in the computer room performs essentially tasks as a data logger system, and supports information which is displayed both in the unit control room via visual display units (VDU) and in the auxiliary control room using appropriate output devices (printers).

The auxiliary control room and the computer operating room are directly accessible for the staff of the unit control room, while the computer room is restricted to the designated personnel.

Local control stands for stand-alone process systems are permissible.

For the postulated case of non-availability or non-accessibility of the unit control room, emergency control desks are installed in 2 separate rooms in the reactor building (bunkered area). These emergency control desks provide the requisite amount of information output to allow the state of the plant to be assessed, and enable safety-related actions, such as reactor shutdown to sub-critical state, to be initiated using operating modules.

Access to the emergency control rooms is not possible without special administrative measures.

Ambient Conditions

- Climatic conditions

The central equipment of the control system is housed in air-conditioned rooms. The following climatic conditions are maintained:

Room temperature:	between +10 °C and +35 °C
Humidity:	unregulated

In the control room area, including the computer room, the guidelines for places of work apply:

Room temperature:	between +18 °C and +30 °C
Humidity:	max. 60 % relative

For local equipment, the following conditions basically apply:

Room temperature:	between 0 °C and 50 °C
Humidity:	no moisture condensation

The ambient conditions for rooms with stringent requirements in regard to temperature, humidity and radiation result in a special design for control components, suitable for withstanding these ambient conditions. The same applies to equipment which is designed to withstand the effects of accidents in the reactor system; here the design is based on the special conditions obtained in the event of an accident.

- Internal and external events

The accident instrumentation is designed to withstand internal and external events.

The remaining reactor protection systems, including the associated power supply, are designed to withstand earthquakes and internal events.

Design of all other equipment in the control system in regard to internal and external events is based on the proven construction used in conventional power plants.

Effects on the equipment of the reactor protection system are ruled out by topographical separation and decoupling.

10.2 Measuring Equipment

Structure of the Measuring System

The measuring system includes essentially the sampling points, the mechanical measuring set-up, and the devices for measured variable conversion, signal transmission, signal distribution and signal display.

The sampling points and the mechanical measuring set-up for linking the sampling point with the measuring transducer are adapted to suit the measuring task involved in each case, and exhibit a similar design throughout the power plant.

To measure physical quantities and convert them into electrical variables, selected suitable standard measuring transducers are used. The output of the transducers is an injected standardized signal.

For temperature measurements (thermocouples, resistance thermometers), the measured variables are also transmitted directly. The thermocouples are in this case cabled up to the sub-distributors with compensation lines. Temperature compensation if performed in the input module in the measured value conditioning function, with the compensation resistor located in the sub-distributor.

The transducers, including their associated test and stop valves, are locally grouped and mounted on measuring frames. Transducers, binary transmitters and mutually connected thermocouples are led by single cables to sub-distributors, which are likewise mounted on these measuring frames or on separate sub-distributor frames.

The sub-distributors are linked to the central electronic rooms via main cables.

Where the massing of transmitters renders it advisable, and where the ambient conditions permit, the signal conditioning cubicles are installed locally, and thus replace the sub-distributors. These cubicles are linked with the other control equipment via bus cables.

In the signal conditioning function, the analogue values are converted into bus signals, limit values are derived and requisite calculations or correction performed.

Signal distribution inside the control system is performed using bus signals. If signals are to be displayed, written or indicated, then they are selectively decoupled via analogue or binary output modules, and passed to the displays, hard-copy outputs or indication equipment as current or voltage signals. The indication equipment is largely located in the desks and Panels of the control room.

The above remarks apply to measurements for the service systems and partially to measurements for the reactor protection system (RPS).

It is a specific feature of the RPS measurements that the linkage from local device to the RPS is in conventional design, i.e. via main cables, with the redundancy regulations of the RPS also being observed for the cable routes. Signal distribution inside the RPS is non-reactive, and utilizes conventional signal distribution modules.

10.3 Binary Control and Machine Protection

Functional Task Definition

Drive Control

In the case of remote-controlled machinery, the drive control serves as the standard interface between the command transmitters (keys, automatic control) and the command receivers (switchgear, drives). It performs all tasks necessary for command processing, monitoring and signalling.

In the drive control, the commands are combined with the interlock and protective criteria so as to ensure that a machine is switched on only if no non-permissible states exist which endanger the machine or the plant.

If situations develop during operations which endanger the machine, than the drive control is designed to utilize protective commands to bring the machine to a safe state.

If power amplification is required for controlling the switchgear installation branch, this is performed by a coupling relay in the switchgear Installation. Depending on the task definition for the machine concerned, the command is stored (locking) in the drive control or in the switchgear installation. The voltage supply and the conditioning function for the drive-linked transmitters (check back contacts, torque contacts) are provided by the drive control system.

The formation of drive-specific disturbance signals, and signalling of operating states, is also a task for the drive control system.

Function Group Control

For controlling systems or subsystems (technologically autonomous areas of the power plant process), function group controls are used as sequential controls or logic controls.

They control start-up, operation and shutdown of systems or subsystems, by switching on and off the appropriate machines or the lower-level function group controls in the technologically correct sequence.

Command output in sequential controls is performed in steps, in a fixed, specified sequence. The next order in the sequence is not carried out until a positive check back signal is received indicating that the preceding step has been successfully performed. The time between command output and command check back is monitored.

Command output and the sequence of command outputs in logic controls are performed only in dependence on process criteria. In the operating phase, the function group control automatically switches on and off the partial-load machinery.

Pre-selection and Reserve Machinery Operations

The pre-selection function enables those machines to be selected among a group of machines, which are to serve as operating or reserve machines.

Automatic switch-on of reserve machines is ensured by appropriate logics for the event of machinery failures during operation.

Structure of the Binary Control System

The binary control system is structured with devices from the Procontrol P system.

In accordance with the hierarchical structure of the power plant process, the binary control system is implemented on two levels:

- Individual level
- Function group level

The individual levels are segregated from each other in functional, equipment-design and electrical terms. Manual interventions in the individual levels are possible in appropriate cases if the high-order level is isolated by suitable commands.

10.4 Analogue Control System

Functional Task Definition

Single variable analogue control

The single variable analogue control is used for continuous analogue control of a process variable. Together with the positioning controllers, it forms the individual control level. For remote-controlled variable-speed drives it also serves as a standard interface between the command transmitters (keys, automatic control) and the analogue control devices. It performs all necessary tasks of control differential formation, command processing, positioning, monitoring and signalling.

In the single variable analogue control, criteria are combined so as to ensure that no non-permissible states occur which could endanger the machine or the plant subsystems. When electric variable-speed drives are used, contactless power amplification is provided.

Voltage supply and conditioning functions for the drive-linked transmitters (limit switches for distance or torque) are provided by the single variable analogue control.

Formation of drive-specific disturbance signals, plus signalling of operating states, is also a task for the single variable analogue control.

Group analogue control

If several analogue controls are required in order to solve a process-engineering job, e.g. feedwater pumping, and these must be jointly controlled or coordinated with each other, then this task is performed by the superimposed analogue control on the group control level.

As master controllers they give set-point values to lower-order controls.

Set-point change-overs and limit curve controls become operative when technological or process-related limits are reached, and influence the set-point assignments.

Set-point controls

Set-point controls, which are incorporated in the process control level, are provided where the task is to control the overall processes so as to ensure that the primary objective of the power plant, to provide sufficient process steam as reliably as possible, is achieved within specified limits.

The set-point controls accordingly form reference variables for the turbines and the reactors, taking into account technological and process-engineering limits affecting the plant as a whole, and also the requirements for the process steam network.

Structure of the analogue control system

The analogue control system is structured with devices from the Procontrol P system.

In accordance with the hierarchical structure, the following 3 levels are implemented:

- Individual control level (single variable analogue control)
- Group control level
- Process control level (set-point controls)

10.5 Protective Equipment

Functional Task Definition

The protective equipment must bring disturbed machines or the disturbed process to a safe state. "Safe" means the state which is non-destructive for the plant and harmless for human beings and the environment.

Protective interventions have priority over all other commands. In dependence on the safety and availability required, and the value of the plant components involved, the measuring transmitters for protective criteria are in single-channel or multiple-channel structure. In the case of multiple-channel measurement structure, the channels are mutually monitored. Disturbed measurements are signalled, isolated if necessary, and the system switches over to the measurements which are still functioning properly.

Design and Structure

Machinery protection

The normal machinery protection is in single-channel or multiple-channel open-circuit design. The protective criteria act directly on the drive control via the signal detection and signal conditioning functions.

Steam Generator Component Protection

The component protection of the steam generators has no safety-engineering importance.

Nevertheless, the associated equipment is designed with multiple redundancies, for reasons of availability and in order to attain the customarily high level of safety in nuclear power plants, so that the design features of the reactor protection system are all also applied to the steam generator component protection system.

Reactor Protection System

For the reactor protection system, a functionally and topographically separated system is provided, which intervenes in operational functions with priority signals and activates safety systems.

The reactor protection system is independent from other control systems, and functions fully automatically, with the exception of manual excitation operations. It is designed with triple redundancy, from the transmitters to the logic circuits, including the electrical power supply.

The switch-off and triggering chains are in triple or quadruple-redundancy design, depending on the requirements involved.

Topographical separation and electrical decoupling ensure that there is no mutual interference in the event of internal disturbances in one of the redundant subsystems.

The reactor protection system functions largely in failsafe and self-reporting mode in the event of defective devices.

The analogue measuring channels are incorporated in the self-monitoring function by means of continuous measuring channel monitoring - comparison of instantaneous values in the redundant measuring loops.

Non-self-reporting components are checked on one or multiple channels for proper functioning in regular in-service inspections (e.g. timing elements for adherence to the preset time, inverting loops and drive control modules).

This equipment for the in-service inspections is installed so as to ensure that the test actions initiated are aborted if the reactor protection system is triggered.

Without actually belonging to the RPS, some machinery protection excitation criteria are made equivalent to the RPS excitation criteria in design and quality terms.

Each of the two reactor units has its own independent RPS. In functional terms, the RPS comprises the equipment required for:

- Measurement
- Signal conditioning
- Limit value signalling
- Logical combination
- Command output to the downstream controls of the active safety equipment
- Self-monitoring, testing and signalling
- The associated power supply

This equipment belongs in the highest safety requirement classification.

Accident detection utilizes as far as possible safety variables which in each case are physically diversified with reference to each other. If this requirement is not fulfilled, the measuring equipment is given a higher-quality structure in comparison to the other measuring chains serving for accident detection. This is implemented by providing at least two redundant excitation functions instead of only one, with the two mutually redundant excitation functions being derived from separate, differently equipped measuring chains.

Protective Actions

The protective actions assigned to the RPS are briefly explained below:

- Reactor scram

Two systems are provided for shutting down the reactor.

First shutdown system:	16 absorber rods in the side reflector.
Second shutdown system:	small absorber spheres (SAS), which when required drop into the 4 bores provided in the reflector noses.

When the reactor scram function is required, the first shutdown system is automatically activated. The upper electric end-position lock for the reflector rods is released, so that they drop by force of gravity. This function is performed by interrupting the power supply, by means of 2 diverse systems.

After approximately 30 seconds, the second shutdown system can be activated by hand. The triggering mechanism for the SAS is in redundant design.

- Closing the penetration termination to the reactor building

Coolant losses via the pipes passing through the biological shield are limited by the RPS, which cuts off these pipes.

- Emergency power diesel start-up

If there is a failure of the normal power supply, then the emergency power generating sets assigned to the RPS are started up.

The consumers are switched on in stages by the RPS control system.

<u>System Structure</u>

- Redundancy

The RPS control equipment is in a redundant structure.

The redundancy of the switchgear equipment presupposes redundancy in the process equipment.

The mutually redundant safety variables for accident handling are assigned to two separate redundancy groups.

The mutually redundant systems are so independent of each other that if redundancies fail because of a failure-triggering event inside the RPS, the remaining redundancies are sufficient to cope with the accident.

The independence of the redundancies or redundancy groups in linkage points is ensured by non-reactive decoupling.

Mutually redundant components of the RPS are topographically separated in their configuration. Topographical separation is dispensed with only if the failure-triggering events do not prevent the triggering of protective actions.

The cables for the measurement function are led through the reactor building an 4 topographically separated cable routes. The cables for the process variables measured for operational purposes may be led together with the RPS cables on one of the 4 cable routes provided, as long as care is taken to ensure that in proper operation and in the case of triggering events in the service systems, the function of the RPS is maintained. A cable must be led from its inception point to its destination an one and the same cable route.

- Combination

The measurement of process variables required for formation of safety variables is performed in 2 of 4 redundancies. This does not include the cases in which any failure can be corrected in less than 100 h, and no service cable is led an the cable routes.

If the possibility exists of detecting accidents through more than two safety variables, then excitations in 2 of 3 redundancies are also permissible.

If RPS signals are used for Signal conditioning outside the RPS; e.g. signals for pen recorders or display units, then these signals are non-reactively decoupled.

Control of active safety equipment by the RPS is structured so as to ensure that triggering of protective actions has priority over operational actions.

- Failsafe characteristics

The RPS triggers protective actions automatically. Manual interventions for triggering protective actions are not required before 30 minutes have expired. Interruption or resetting of protective actions is carried out only if precisely specified conditions are fulfilled.

The RPS is designed to be self-monitoring.

The RPS is designed so as to ensure that during power operation, proper functioning of the subsystems is detected, and thus proper functioning of the entire RPS is demonstrated.

All equipment used has been certificated for suitability and quality.

Power supply to the equipment comes from 4 separate sources.

The RPS is independent of the service systems.

The Signals from the RPS measuring equipment may be used for binary and analogue control only if their failure would not lead to an accident or if it is demonstrated that these accidents would be detected by the selection of the RPS safety variables.

For protection against external events, the RPS is located where necessary in an area guarded against external events. These components (equipment) are located in a non-guarded area only if their failure would automatically trigger protective actions.

The emergency control room, which even after external events provides an overview of the measures automatically initiated by the RPS and the safe plant condition (indicators, pen recorders), is likewise located in an area guarded against external events.

The emergency control room contains the devices which must be retained in being even after destruction of the control room, redundantly to the control room itself.

- Twin-unit plant

The reactor protection systems of the two units are fully separate in functional terms.

The cables of the reactor protection systems of the 2 reactor blocks may be laid together on the redundant routes. The equipment may also be installed together in the redundant rooms. Functionally, however, the reactor protection systems for the two units are absolutely independent. Operation of one unit is independent of the state of the other unit.

10.6 Process Communication

Functional Task Definition

The communication equipment forms the interface between the process (plant, switchgear, control system) and the operator. Its task is firstly to inform the operator an operating states or disturbances (displays, pen recorders, monitors, indicators, printers), and secondly to enable the operator to intervene in the process via the binary and analogue control systems (action devices), and also to intervene so as to prevent or limit disturbances.

Design and Structure

Control Room Equipment

The unit control room contains all equipment required for controlling and monitoring the power plant process.

In accordance with the importance and frequency of the activities involved, the unit control room is divided into the following functional areas:

- Main control room
- Auxiliary control room
- Documentation area
- Communication area

The main control room is permanently manned and designed for 2-man operation.

The main control room consists of a desk with a vertical panel and integrated VDU's.

The desk contains all systems required for start-up, shutdown and power operating mode.

The plant is operated from the central section of the desk. Here the operator can read the information, and influence the process using operator keyboards.

Important function groups, analogue controls, alarm signals and process variables are also provided in conventional form as a back-up in the two side sections of the desk.

The auxiliary control area is located in front and to the side of the main control area. It is not permanently manned, and serves only for fault correction, start-up preparation, and for operating auxiliary power and ancillary systems.

Here, as in the main control area, the operator can read his information. He can intervene in the process using operator keyboards, carry out start-up preparation, and operate ancillary systems.

A rapid overview of the plant status is provided for the operator by the unit overview mimic diagram and displays for unit characteristic values. The unit overview mimic diagram and the displays are arranged in front of the main control area in the operator's direct line of sight.

The documentation area contains mainly pen recorders and printers which are not directly required for process control, and is located in the secondary control room.

The communication area, which essentially serves for internal and external personnel communication, is located behind the main control stand. It consists of a communications desk and essentially contains paging and intercom systems, plus alarm triggering functions.

Annunciation Equipment

Every incidence of limit values being exceeded, plus disturbance criteria and protective interventions at individual machines, are signalled.

All individual signals are received and documented by the data logger system. General signals are acquired and signalled by the visual/acoustic annunciation system, with these general signals being structured either in machine-oriented or process-oriented form.

The annunciation system is basically independent of other control functions.

Process Computer System

The task of the process computer system is:

- To acquire all individual signals, display them an monitors, and print them out
- In the event of a disturbance occurring, to render its chronological history visible, and thus easier to reconstruct, by recording particular variables
- To monitor the ongoing process by acquiring selected binary values, storing them, and outputting them to printers

Linkage Concept

The control components are linked essentially via the bus.

The special characteristics of the bus system are utilized in order to minimize the quantity of cables, to reduce the fire hazard from cables, and to facilitate fire-protection measures. The bus cabling is led to local points, as far as possible, and where appropriate. The decision on whether to use conventional cabling via individual cores or bus cabling is taken on the basis of configuration, ambient conditions and costs.

10.7 Control System Cabling

The following requirements are complied with for the cabling:

- cabling for the control systems is mainly on cable racks
- separate laying of heavy-current and control system cables
  Minimum distance between control system cables and l.v. cables; 30 cm/kV
  Minimum distance between control system cables and m.v. cables: 60 cm/kV
- Individual cables are laid in conduit with open bends. Adequate edge protection shall be provided, e.g. sleeves.

APPENDIX B

MODEL OF A SECONDARY CIRCUIT FOR A HTR COGENERATION PLANT

(ALSTOM CONTRIBUTION)

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Advanced High Temperature Reactor for Cogeneration of Heat and Electricity R&D (ARCHER)

1.0 Summary

Projections have indicated that global energy consumption will continue to increase despite the various conservation and efficiency improvement measures. These measures will in general reduce the rate of increase of energy consumption, but their effect is not large enough to stabilise consumption at current values.

One of the prime concerns of sustainable development is how to find energy resources to meet the increase in consumption given the constraints regarding the environmental impacts of fossil fuels combustion, depletion of fossil fuel reserves and the volatility of fuel prices. Nuclear power could be part of the solutions because sustainable, non-polluting, energy could be provided by nuclear energy.
The next generation of nuclear reactors, the Gen IV high temperature reactors (HTR), is expected to lead to innovative systems with more inherent and passive safety features. It may offer socially acceptable, environmental benign and competitive solutions to the world's energy problems by addressing the areas of safety and reliability, proliferation resistance and physical protection, economics and sustainability. The HTRs can play an important role by providing high temperature heat while also co-generating electricity. These considerations informed the ARCHER (Advanced High Temperature Reactor for Cogeneration of Heat and Electricity Research & Development) project under the aegis of the European Commission's 7th Framework Programme of the European Atomic Energy Community (Euratom) for nuclear research and training activities.

ALSTOM is a partner in the ARCHER project and the focus of this study by the Future Technologies Execution department was on the review of available cogeneration cycle concepts based on ALSTOM experience with fossil fuel plant, assessment of the feasibility of HTR cogeneration secondary systems and finally, conceptual modelling and thermodynamic analysis of an HTR plant for cogeneration of heat and electricity.

Principal findings include

- Efforts to improve efficiency and the increasing concern over the environmental impact of power generation has helped to improve the popularity of cogeneration.
- Various applications of cogeneration include industrial application, commercial/ institutional/ residential application and district energy systems.
- The greatest potential for increased utilisation of cogeneration is in the industrial sector.
- Industrial applications of cogeneration can be categorised into low temperature processes (lower than 100 °C), medium temperature processes (100 – 300 °C), high temperature processes (300-700 °C), very high temperature processes (higher than 700 °C).
- It is usually advisable that CHP installations be sized base on the heat demand of an industrial unit, however every application has its own unique characteristics.
- Though the viability of employing nuclear heat sources for district heating and industrial processes has existed since the very start of nuclear development, a substantial penetration into the commercial heat market is yet to take place.
- Due to its unique abilities, HTRs will enable a range of applications not previously available to the nuclear industry, including a number of process industry applications.
- Apart from the technical feasibility of the HTR cogeneration systems, other equally important requirements include the industrial heat demand compatibility, economic feasibility, as well as safety and licensing requirements.
- From the analyses of both industrial processes and heat transfer technology for HTR heat supply, it seems obvious that HTR-steam cycle coupling for process steam production and electricity generation would be the most appropriate scheme for a near-term demonstration plant.

- However there may be need for further studies on steam generator using helium as the hot stream.
- HTR cogeneration plant can support process heat demand requiring process steam at temperature up to 600 °C (or 550 °C as the case may be) considering existing or near term technology.
- Thermodynamic analysis of HTR steam cycle cogeneration plant indicated an energy utilisation factor of about 71% at heat to power ratio of 2.44.
- Addition of reboilers could help to increase the safety barrier between the primary reactor circuit and the industrial process and hence reduce the possibility of carry-over of radioactive contaminants to the process side.
- Design with total process steam production up to 540 tonnes per hour (corresponding to a maximum heat to power ratio of about 6.94) is achievable with a 600 MW HTR reactor.
- Study of the system performance criteria shows satisfactory results. The system can shift energy between electricity generation and heat supply as process steam demands vary, while keeping the reactor power constant.

2.0 Introduction

2.*1 Background and Motivation*

Despite the various conservation and efficiency improvement measures, projections have shown that global energy consumption will continue to increase. These measures will in general reduce the rate of increase of energy consumption, but their effect is not large enough to stabilise consumption at current values. This can be attributed to population growth and economic development. Hence present energy supplies for the generation of electricity, industrial process heat application and other forms of energy usage, which are largely fossil fuel resources based (see Figure 1), are facing major constraints. One of the prime concerns of sustainable development is how to find energy resources. Nuclear power could be part of the solutions because non-polluting energy could be provided by nuclear energy. Nuclear energy has the potential to emerge as one of the most significant carbon-free sources and contribute to a more secure energy world. It is a proven technology that has demonstrated over many years a high level of safety and reliability. The next generation of nuclear reactor, the high temperature reactors (HTR), is expected to lead to innovative systems with more inherent and passive safety features. It may offer socially acceptable, environmental benign, and competitive solutions to the world's energy problems by addressing the areas of safety and reliability, proliferation resistance and physical protection, economics and sustainability (Verfondern, 2007).

Today, nuclear power almost exclusively impacts only electricity generation and accounts for 16% of the world's demand but the greatest challenges for sustainable development lie in other areas of energy consumption. (Verfondern, 2007, Gauthier et al., 2007). Other sectors like heat are still waiting to be penetrated by nuclear-based energy source. On the other hand, electricity represents less than a third of the final energy, which is dominated by the heat and transport market (see Figure 2). The major part of the world's primary energy is consumed in the form of heat by various branches of industry or for heating homes. Practically, the heat sector is completely dependent on fossil fuels. Hence in order to reduce our dependence on fossil fuels, nuclear-based energy source must be deployed to impact the heat market as well. Deployment of HTR would provide a path to significantly impact this broad segment of the energy market with environmental, economic, and energy security benefits. According to Lommers et al. (2011), increasing pressure from environmental concerns suggest that near-term solutions are required.

The industrial sector is known for high-energy demand both in term of heat and electricity. There are many industrial sectors such as paper and pulp, food industry, automobile industry, textile manufacturing, chemical industry etc, which have a high demand for electricity and heat/steam at various temperature and pressure (Verfondern, 2007). These are areas where nuclear energy specifically from HTR can play an important role, providing high temperature heat while also co-generating electricity. These were the considerations that informed the ARCHER (**A**dvanced High Temperature **R**eactor for **C**ogeneration of **H**eat and **E**lectricity Research & **D**evelopment) project under the aegis of the European Commission's 7th Framework Programme of the European Atomic Energy Community (Euratom) for nuclear research and training activities. In line with the Sustainable Nuclear Energy Technology Platform (SNETP) Strategic Research Agenda (SRA) and Deployment Strategy (DS), the project aims to extend the state-of-the-art European (V)HTR technology basis with generic technical effort in support of nuclear cogeneration demonstration. The results of the project will support the third strategic pillar of SNETP, which is to enlarge the nuclear fission portfolio beyond electricity production, and the establishment of a Nuclear Cogeneration Industrial Initiative, which includes effective (international) nuclear cogeneration demonstration.

Energy-intensive industrial sites in the food processing, pulp & paper, chemicals, metals and oil refining sectors have been traditional hosts for cogeneration (otherwise known as combined heat and power, CHP) facilities, in fact, these industries represent more than 80% of the total global CHP capacities (IEA, 2008). These plants generally have high process related thermal requirements not subject to daily and seasonal weather-related fluctuations, so energy is an important part of their business (IEA, 2008). The high temperature reactor has long been recognised as a promising technology for high efficient electricity generation and high temperature process heat applications (Gauthier et al., 2006). The supply of heat by

HTR brings a solution inaccessible to conventional nuclear power plants for high temperature. It brings to the large industrial heat applications the fuel cost predictability of nuclear fuel with the efficiency of a high temperature heat source free of greenhouse gases emissions. Thus, this opportunity brought by HTR technology complies with EU policy goals with respect to greenhouse gas emissions and enhanced security of supply (Angulo et al., 2012).

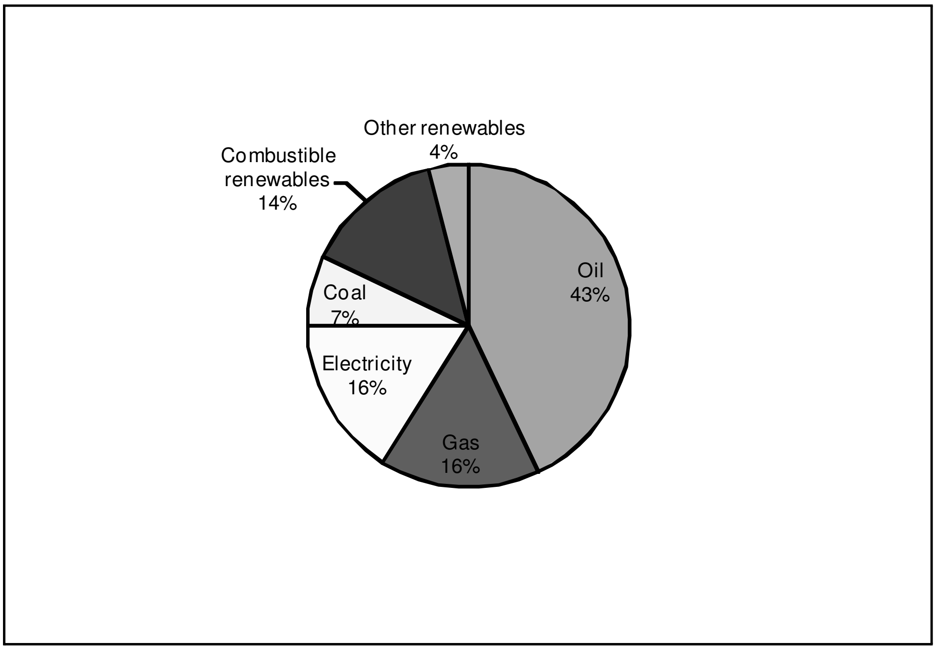

Figure 1 Forms of energy consumption worldwide (Futterer et al., 2006)

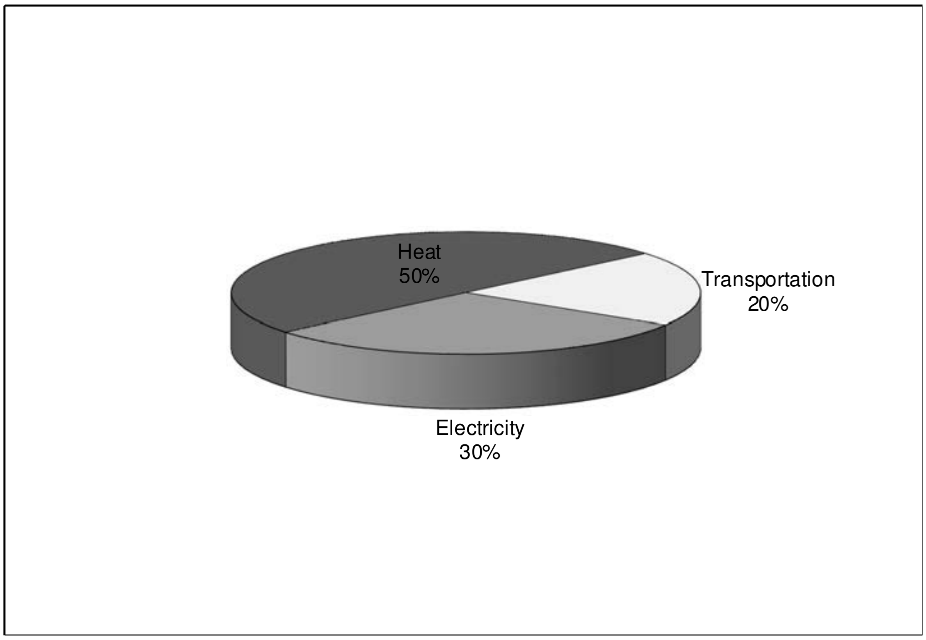

Figure 2 Energy consumption by application (Khamis, 2011)

2.2 Objective

The objective of this study is to contribute to Sub-Project 1 (System Integration) of ARCHER project by carrying out the following activities:

- Review available cogeneration cycle concepts.
- Assess the feasibility of HTR cogeneration secondary system.
- Model and analyse the secondary system of demonstration plant for cogeneration of heat and electricity with HTR using information from previous nuclear cogeneration related program.
- Review alternative coupling schemes for the secondary system.

3.0 Review of Available Cogeneration Cycle Concepts

3.1 What is Cogeneration?

Cogeneration (also known as combined heat and power, CHP) is the energy generation process in which mechanical (or electrical) power and useful thermal energy are produced simultaneously by depleting only one primary energy source. The mechanical energy is most often used to drive a generator to produce electricity; it can also be used to drive rotating equipment such as compressors, pumps and fans. The thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process application. During the operation of a conventional power plant, large quantities of heat are rejected to the atmosphere either through the cooling circuits (steam condensers, cooling towers, water coolers in Diesel or Otto engines, etc) or with the exhaust gases. Most of this heat can be recovered and used to cover thermal needs, thus increasing the overall fuel utilisation from 30-55% of utility power plant to over 80% of a cogeneration system. This means that in cogeneration systems, rather than using energy in the fuel for a single function, as typically occurs, the available energy is cascaded through at least two useful cycles – first to produce power and then a second time in the form of heat for district heating or industrial use.

Cogeneration is not a new concept; it has been around for over 100 years. It first appeared in the late 1880s in Europe and in the United States. Early in the 20th century, before there was an extensive network of power lines, many industries had cogeneration plants. Most of the industrial plants generated their own electricity using coal-fired boilers and steam-turbine generators. Many of these plants used the exhaust steam for industrial processes (EDUCOGEN, 2001 and Hinrichs, 2004). However when central electric power plants and reliable utility grids were constructed and the costs of electricity decreased, many industrial plants began purchasing electricity and stopped producing their own. Other factors that contributed to the decline of industrial cogeneration were the increasing regulation of electric generation, low energy costs which represent a small percentage of industrial costs, advances in technology such as packaged boilers, availability of liquid or gaseous fuels at low prices, and tightening environmental restrictions. But the decline in cogeneration started being inverted after the first dramatic rise in fuel costs in 1973. Systems that are efficient and can utilize alternative fuels have become more important in the face of price rises and uncertainty of fuel supplies. Also increased concern over the environmental impacts of energy generation has help to improve the popularity of cogeneration because cogeneration results in a decrease of pollutant emissions (BEE, 2006).

Figure 3 provides a helpful description of illustrative comparison of cogeneration (or CHP) and separate heat and power (SHP) systems. It shows the efficiencies of energy conversion in each unit. Separate heat and power (SHP) refers to the conventional practice of centrally generating electricity at large-scale power plants and separately generating useful heat with boilers onsite for non-electric applications such as industrial processes or space and water heating. Due to utilisation of heat from electricity generation and the avoidance of transmission and distribution losses because electricity is generated on site, cogeneration achieves a significant improvement in fuel utilisation compared with separate power stations and heat only boilers.

Cogeneration plant consists of four basic components (seai, 2006; and Thumann and Mehta, 2008):

- A prime mover
- An electricity generator
- A waste heat recovery system
- Operating control systems

The prime mover is an engine or turbine, which produces mechanical energy. The generator converts the mechanical energy to electrical energy. The waste heat recovery system is one or more heat exchangers that capture exhaust heat or engine coolant heat and convert that heat to a useful form. The operating control systems ensure that the individual system components function together. These basic elements are well-established items of equipment, of proven performance and reliability. Alstom is an original equipment manufacturer (OEM) of the major power plant components that are required for cogeneration plants. Figure 4 shows Alstom's cogeneration plant main components.

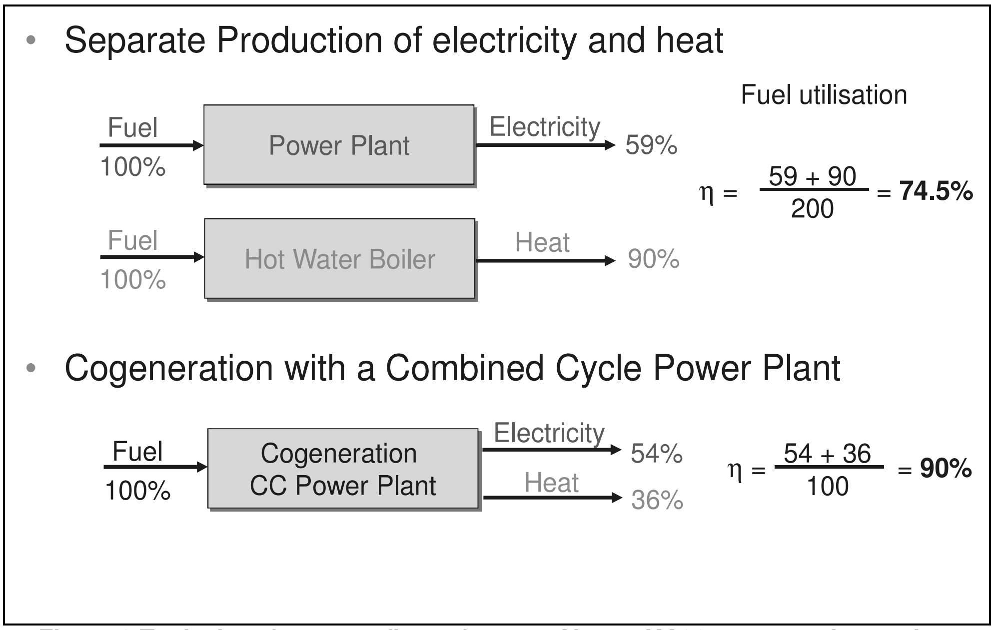

Figure 3 Typical performance figure from an Alstom KA26 cogeneration project

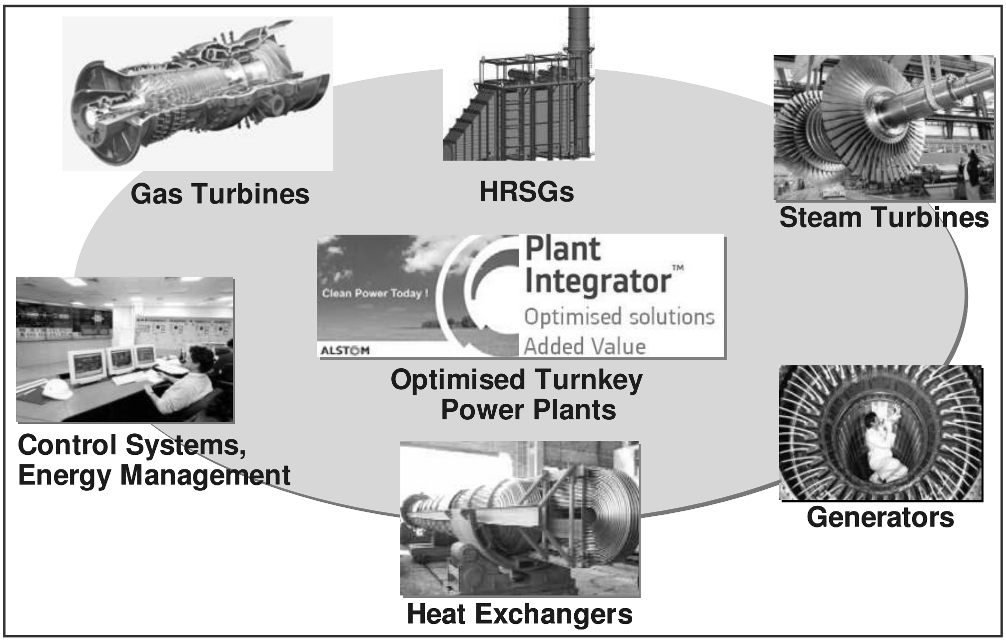

Figure 4 Cogeneration power plant main components

3.2 Applications of Cogeneration Systems

Cogeneration is particularly suited to applications with high and relatively steady continuous demand for both heat and power. The concept can be related to power plants of various sizes ranging from small scale for residential building to large scale cogeneration systems for industrial purposes to fully grid connected utility generating stations. Cogeneration can be used in many industries/applications, often with very different requirements (see Figure 5). Factors to be considered for the determination of cogeneration systems suitability include (IEA, 2008; BEE, 2006 and Kosanovic, 2009):

- The cost of buying electric power from the grid relative to the cost of fuel (a.k.a "Spark Spread"). A ratio of electricity to fuel cost of at least 2.5:1 is appropriate;
- High thermal load. Relatively high requirements for heating and/or cooling. CHP system is normally sized to meet thermal load;
- Long operating hours (>5,000 hours/year);
- Good coincidence between electric and thermal loads;
- The ability to connect to the grid (if present) at a reasonable price with the availability of back-up and top-up power at reasonable and predictable prices;
- Availability of space for the plant and short distances for heat transport;
- Access to fuels;
- Project completion time; and
- Project cost and long term benefits.

For convenience, the various applications of cogeneration systems can be grouped into one of three categories:

1. **Industrial applications:** The greatest potential for increased utilisation of cogeneration is in the industrial sector and the sector represents the largest share of the current installed capacity (CRES, 2001). In many industries, both electricity and heat is required (electricity to drive machines or for the grid and heat for the processes) and cogeneration facility would be able to supply both products from a single fuel stream. Cogeneration potential exists in the following industries: food and beverages, textiles, forestry, agriculture, pulp and paper processing, chemicals/petrochemicals processing, petroleum refineries, fertilizer production, cement production, metals processing, glass furnaces, ceramics, and wood industries. They can be classified according to the temperature level of the required heat (EDUCOGEN, 2001):
    - Low temperature processes (lower than 100 °C), e.g. drying of agricultural products, space heating or cooling, hot water.
    - Medium temperature processes (100 – 300 °C), e.g. processes in pulp and paper industry, sugar factories, certain chemical industries, e.t.c. In these processes heat is usually supplied in the form of steam.
    - High temperature processes (300-700 °C), e.g. in certain chemical industries.
    - Very high temperature processes (higher than 700 °C), e.g. in cement factories, primary metal industries, glass works, e.t.c.

    Application of cogeneration systems in industrial zones or park is of particular interest. The electrical and thermal load of all the industries together is much higher than those of each individual industry. Furthermore, the duration of load is longer and the variation with time is much smaller than that of each industry considered separately. These conditions are ideal for cogeneration by a central system.
2. **Commercial, Institutional and Residential applications:** Examples of commercial, institutional and residential cogeneration users include houses and apartment buildings, hotels, office buildings, schools and universities, stores, supermarkets and shopping centres, swimming pools and leisure centres, restaurants and hospitals, which tend to have significant energy costs as a percentage of total operating costs as well as balanced and constant electric and thermal loads. Co-generated heat is used for domestic hot water, space heating or cooling, laundry facilities, dryers, swimming pool water heating, e.t.c. (EDUCOGEN, 2001). Commercial companies are increasingly considering cogeneration as a cost-effective way to reduce their carbon footprint. Residential "micro" CHP technologies are also been developed and sold at the individual household level and thus represent a potential mass market for cogeneration (IEA, 2008).

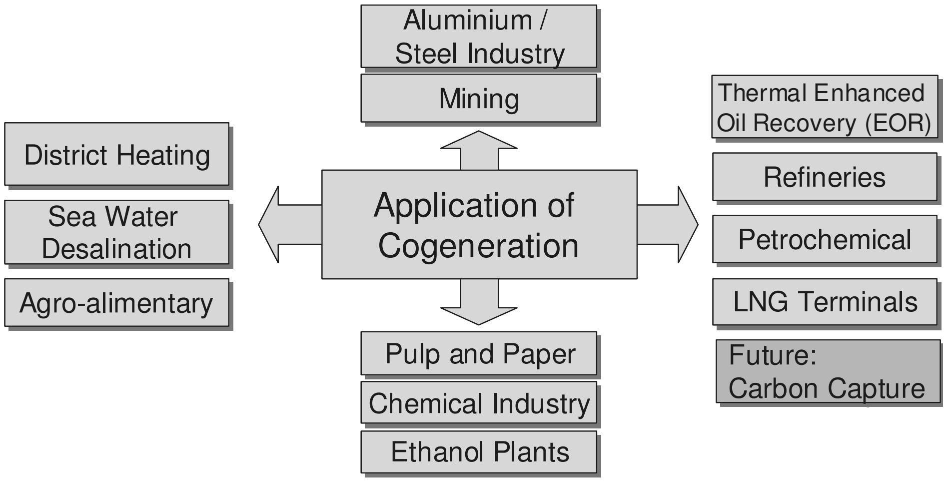

Figure 5 Industries/applications requiring power and heat (Source: Alstom)

3. **District Energy Systems:** A District energy system primarily focuses on supplying low- and medium-temperature heat demands (space heating and hot tap water preparation), by recycling upgraded waste heat from CHP plants in addition to the supply of electric power to nearby cities or part of a city, industries, e.t.c. The recovered heat from the plant serves to warm up water, which is transported via a well-insulated network of pipes to the customer premises. It can cover heat demands in all buildings within reach of the heat network including residential, public, and commercial buildings as well as low-temperature industrial heat demands. Population density is a key consideration for district energy system because the system relies on a concentrated demand for space heating/conditioning. This is important because of the need to minimise the distance that heat can be transported, and due to the high costs of installing heat distribution systems.

3.3 Advantages of Cogeneration Systems

1. **Technical:** The principal technical advantage of cogeneration systems is their ability to improve the efficiency of fuel use in the production of electrical and thermal energy (Kanoglu and Dincer, 2009). Less fuel is required to produce a given amount of electrical and thermal energy in a single cogeneration unit than is needed to generate the same quantities of both types of energy with separate, conventional technologies. By using fuel energy for simultaneous production of power and heat, cogeneration systems can be very energy efficient (>80%). Typical performance figures from an Alstom KA26 cogeneration project for district heating indicates a fuel utilization of 90% compared to 74.5% with separate production of heat and power. By locating the cogeneration plant near the end user, electricity transmission losses are also reduced further improving overall energy efficiency. Another important benefit of applying CHP technology is to reduce dependence on the electrical grid. For some industrial processes, the consequences of losing power for even a short period of time are very costly.
2. **Environmental:** The technical advantages of cogeneration lead to significant environmental advantages. That is, the increase in efficiency and corresponding decrease in fuel use by a cogeneration system, compared to other conventional processes for thermal electrical energy production, normally yield larger reductions in emission of greenhouse gases (particularly CO_2 emissions) and other environmental pollutants. The reduction in greenhouse gas emissions can be as large as 50% in some situation, while the same thermal and electrical services are provided (Kanoglu and Dincer, 2009). Hence cogeneration systems can contribute to efforts to combat climate change (Rosen, 2009). It is estimated that for every 1 MW of CHP installed, CO_2 emissions are reduced by at least 1,000 tonnes per annum (seai, 2006). The EU directive supports power from cogeneration as an environmental-friendly solution (green power) with

Certificate of Origin for the power (the operator can achieve a higher price for the power produced).

3. **Economical:** A major economic incentive for applying CHP technology is to reduce operating expenses by generating electricity at a lower cost than it can be purchased from the electricity utility provider. Favourable conditions for implementing cogeneration are when the price of electricity is high and the price of fuel is low. The overall energy bill of the users can be reduced, particularly when there is a simultaneous need for both power and heat at the site, and a rational energy tariff is practiced in the country (BEE, 2005). Even for situations where the costs of cogeneration and non-cogeneration options are similar the other advantages of reduced fuel use and emissions can still allow the cogeneration option to be preferred.

3.4 Cogeneration Technologies

Available cogeneration options can be categorised based on the prime mover technologies even though the systems also include other components. The prime mover is the heart of the cogeneration system. The major commercially available cogeneration systems are: steam turbine cogeneration, gas turbine cogeneration, combined cycle cogeneration and reciprocating internal combustion engine cogeneration.

3.4.1 Steam turbine cogeneration

The thermodynamic cycle for the steam turbine is the Rankine cycle. Steam turbines are highly reliable and can meet multiple heat grade requirements. The capacity of steam turbines can range from 50kW to several hundreds of MWs for large utility power plants (UNEP, 2006). A system based on steam turbine consists of a heat source, a steam turbine and a heat sink. The most common heat source is a boiler, which can burn any type of fuel or certain combination of fuels, and produces high-pressure, high-temperature steam. In place of a boiler, a nuclear reactor can be used. The high-pressure steam is then expanded through the turbine to a lower pressure steam to produce mechanical energy, which in turn, drives a device such as an electric generator. The steam is then exhausted either to a condenser at vacuum conditions or into an intermediate temperature steam distribution system that delivers the steam to the industrial or commercial application. The condensate from the condenser or from the steam utilisation system returns to the feedwater pump for continuation of the cycle. Ideal applications of steam turbine-based cogeneration systems include medium- and large-scale industrial or institutional facilities with high thermal loads and where solid or waste fuels are readily available for boiler use. The two type of steam turbines most widely used are the non-condensing (or back pressure) and the extraction-condensing types. Both types work well in CHP applications because they offer a wide range of design flexibility to match process heating demand and performance specifications. The choice between backpressure turbine and extraction-condensing turbine depends mainly on the quantities of power and heat, quality of heat, and economic factors.

3.4.1.1 Back pressure (non-condensing) steam turbine systems

A back pressure steam turbine is the simplest configuration (Figure 6). Steam exits the turbine at a pressure higher or at least equal to the atmospheric pressure, which depends on the needs of the thermal load. It is also possible to extract steam from intermediate stages of the steam turbine, at a pressure and temperature appropriate for the thermal load. Steam turbines that exhaust the entire flow of steam at one location are known as straight non-condensing steam turbines, while steam turbines that exhaust steam at two or more locations are known as extraction non-condensing steam turbines. After the exit from the turbine, the steam is fed to the load, where it releases heat and is condensed. The condensate returns to the system with a flow rate which can be lower than the steam flow rate, if steam mass is used in the process or if there are losses along the piping. Make up water retains the mass balance.

The back-pressure system has the following advantages (EDUCOGEN, 2001):

- Simple configuration with few components.
- The costs of expensive low-pressure stages of the turbine are avoided.
- Low capital cost.
- Reduced or even no need of cooling water.
- High total efficiency, because there is no heat rejection to the environment through a condenser.

The disadvantages include (EDUCOGEN, 2001):

- The steam turbine is larger for the same power output, because it operates under lower enthalpy difference of steam.
- The steam mass flow rate through the turbine depends on the thermal load. Consequently, the electricity generated by the steam is controlled by the thermal load, which results in little or no flexibility in directly matching electrical output to electrical load. Therefore, there is need of a two-way connection to the grid for purchasing supplemental electricity or selling excess electricity generated. Increased electricity production is possible by venting steam directly to the atmosphere, but this is very inefficient, it results in waste of treated boiler water and, most likely, in poor economic as well as energetic performance.

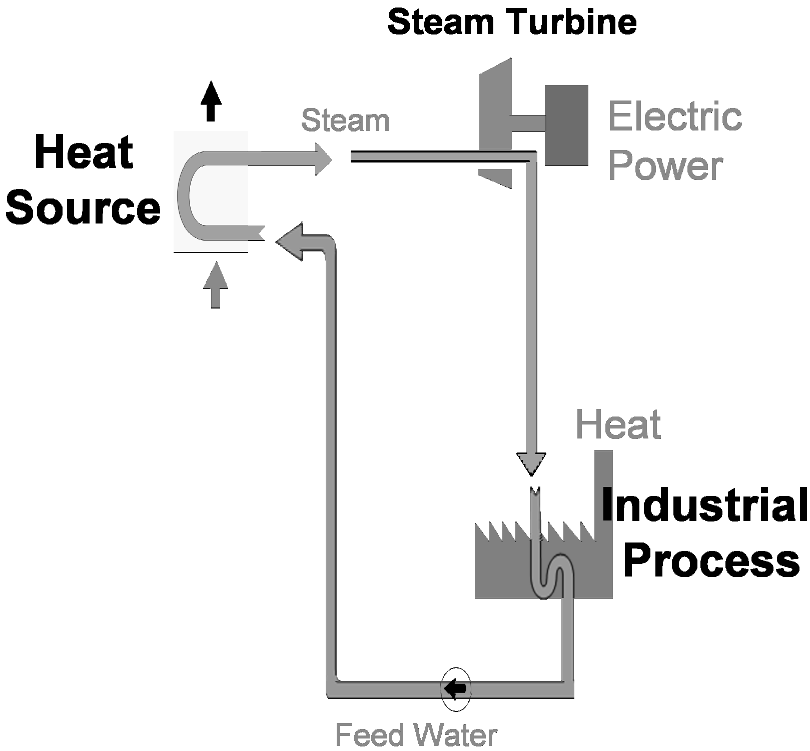

Figure 6 Back pressure steam turbine cogeneration system

3.4.1.2 Extraction condensing steam turbines

Condensing steam turbines are steam turbines designed so that some or all of the steam exits at a low pressure (less than atmospheric). The steam for the thermal load is obtained by extraction from one or more intermediate stages at the appropriate pressure and temperature. The remaining steam is exhausted to the pressure of the condenser, which can be as low as 0.05 bar with a corresponding condensing temperature of about 33 °C. It is rather improbable that such low temperature heat finds useful applications. Consequently, it is rejected to the environment. In comparison to the back pressure system, the condensing type turbine has a higher capital cost and in general, a lower efficiency. However, to a certain extent, it can control the electrical power independent of the thermal load by proper regulation of the steam flow rate through the turbine. The configuration of an extraction condensing steam turbine is shown in
Figure 7.

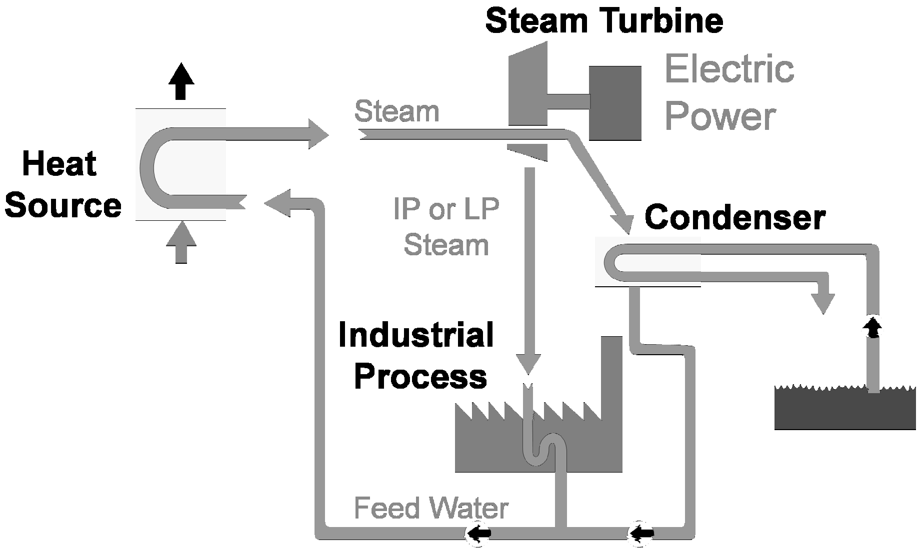

Figure 7 Extraction-condensing steam turbine cogeneration system

3.4.2 Gas turbine cogeneration systems

The thermodynamic cycle associated with gas turbine systems is the Brayton cycle; the thermodynamic steps include compression of atmospheric air, introduction and ignition of fuel, and expansion of the heated combustion gases through the turbine. The developed power is used to drive the compressor and the electric generator. The exhaust gases leave the turbine at a considerable temperature (450-600 °C), which makes high-temperature heat recovery for various heating and cooling application ideal. The exhaust gases can be used in the following ways: for direct firing or drying process, to raise steam at medium or low pressure for process or space heating, to generate hot water and to raise steam in a heat recovery steam generator (HRSG) at high pressure for use in a steam turbine.

A gas turbine based system is much easier to install on an existing site than high-pressure boiler plant and a steam turbine. This, together with reduced capital cost and the improved reliability of modern machines, often makes gas turbines the optimum choice. But the flexibility between power and heat production is very low; for a given electricity production, a certain heat output is achieved and vice versa. The concept does not provide the flexibility that is typically required.

Gas turbines for continuous duty are traditionally divided into aero-derivative gas turbine and industrial gas turbines; the division is based on the differences in design philosophy. Aero-derivative gas turbines for stationary power are adapted from their jet engine counterpart. These turbines are light and thermally efficient, however, are limited in capacity. Industrial or frame gas turbines are available between 1MW up to about 400 MW. They are more rugged, can operate longer between overhauls, and are more suited for continuous base-load operation. However, they are less efficient and much heavier than the aero-derivatives.

A gas turbine can operate either in open cycle or in a closed cycle. Most of the currently available gas turbines systems, in any sector of applications, operate on the open Brayton cycle (Figure 8). In closed system, the working fluid (usually helium or air) circulates in a closed circuit (Figure 9). It is heated in a heat exchanger before entering the turbine, and it is cooled down after the exit of the turbine releasing useful heat. Thus the working fluid remains clean and it does not cause corrosion or erosion. Source of heat can be the external combustion of any fuel. Also, nuclear energy or solar energy can be used.

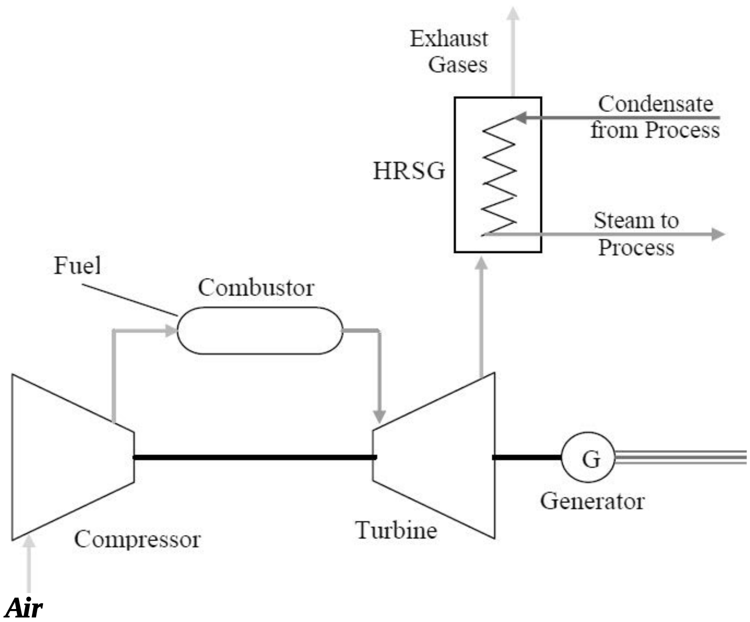

Figure 8 Open cycle gas turbine cogeneration system (UNEP, 2006)

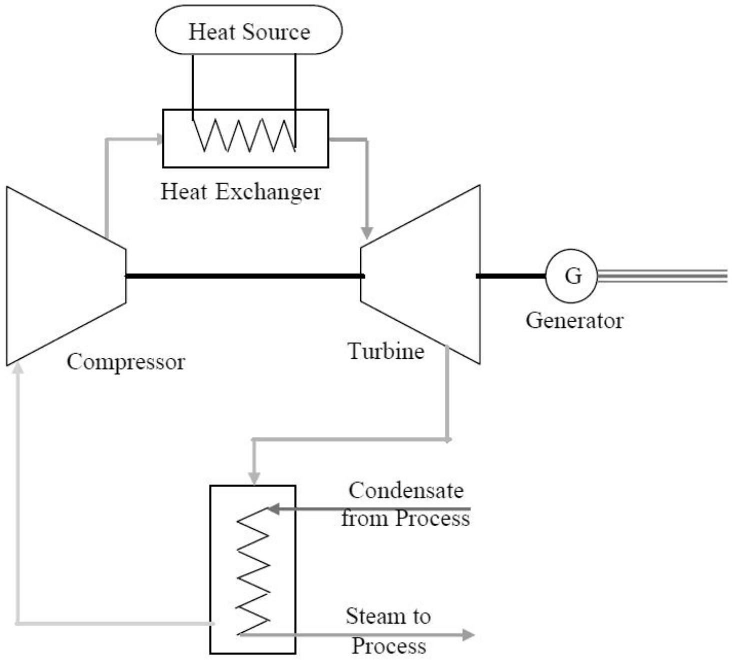

Figure 9 Close cycle gas turbine cogeneration system (UNEP, 2006)

3.4.3 Combined cycle cogeneration system

The term "combined cycle" is used for systems consisting of two thermodynamic cycles, which are connected with a working fluid and operate at different temperature levels. The high temperature cycle rejects heat, which is recovered and used by the low temperature cycle to produce additional electrical or (mechanical) energy, thus increasing the electrical efficiency. The most widely used combined cycle systems are those of gas turbine-steam turbine cycles. The power concentration (i.e. power per unit volume) of the combined cycle system is higher than the one of the simple gas turbine or steam turbine cycle. The maximum possible steam temperature with no supplementary firing is by 25-40 °C lower than the exhaust gas temperature at the exit of the gas turbine, while the steam pressure can reach 80 bar. The ideal mix of power delivered from the Brayton and Rankine portions of the combined cycle is 70% and 30%, respectively.

In Figure 10, a backpressure steam turbine is added to the gas turbine and the steam from the HRSG is first used to produce electricity and then supplied at the required, low pressure to the heat consumer. This arrangement produces more power and less heat-but still the heat production depends on the power produced. The characteristics include high fuel efficiency, relatively simple configuration and relatively low investment. But the system suffers from low flexibility between power and heat production and average part load efficiency. The solution with extraction condensing steam turbine shown in Figure 11 offers the required flexibility between power and heat production. The steam extracted from the steam turbine can be adjusted depending on the requirements and the power and steam are not connected. This solution has also a high fuel utilisation factor, but at a higher investment cost and requires cooling for the condenser. Table 1 gives a summary of the advantages and disadvantages of gas turbine and the combined cycle options.

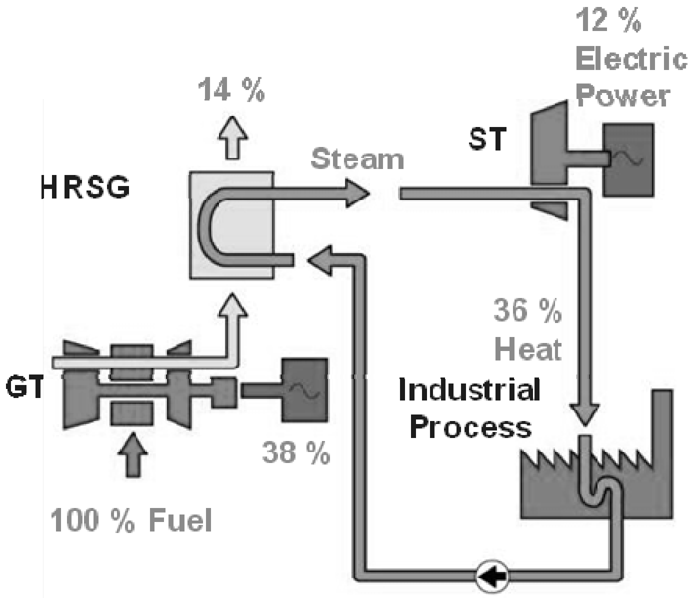

Figure 10 Combined cycle cogeneration plant with back-pressure steam turbine (Source: Alstom)

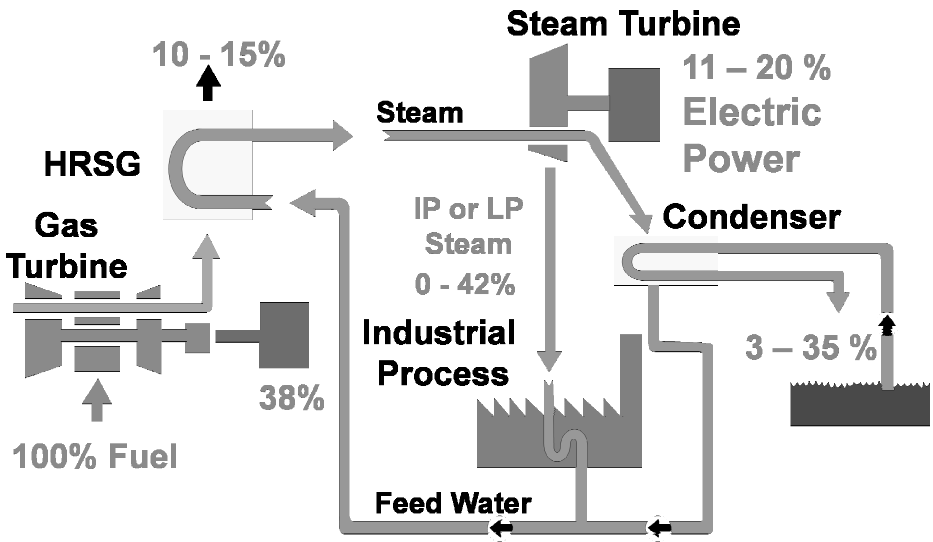

Figure 11 Combined cycle cogeneration plant with extraction condensing steam turbine (Source: Alstom)

Table 1 Summary of gas power plants and combined cycle cogeneration options (Source: Alstom)

Option	Advantage	Disadvantage
Gas turbine with Heat Recovery Steam Generator (HRSG)	- Good fuel efficiency - Simple plant - Short delivery time	- Moderate part load efficiency - Less suited for low quality fuel - Limited flexibility
Combined cycle power plant with back pressure steam turbine	- Good fuel efficiency rating - Relative low capital cost	- Average to moderate part load efficiency - Less suited for low quality fuel - Limited flexibility
Combined cycle power plant with extraction / condensing steam turbine	- Good flexibility between power and heat production - Moderate investment cost	- Less suited for low quality fuel - Moderate cooling water demand

3.4.4 Reciprocating engine cogeneration systems

Reciprocating engines (Figure 12), also known as internal combustion engines (IC) engines are among the most widely used and most efficient prime movers for low and medium power cogeneration units (CRES, 2001). Energy in the fuel is released during combustion and is converted to shaft work and heat. Shaft work drives the generator, while heat is liberated from the engine through coolant, exhaust gas and surface radiation (OSEC, 1999). Approximately 60-70% of the total energy input is converted to heat. There are four sources of usable waste heat from a reciprocating engine: exhaust gas, engine jacket-cooling water, lube oil cooling water, and turbocharger cooling. Recovered heat is generally in the form of hot water or low-pressure steam (<30 psig). The high temperature exhaust can generate medium pressure steam (up to about 150 psig), but the hot exhaust gas contains only about one half of the available thermal energy from a reciprocating engine. Some industrial CHP applications use the engine exhaust gas directly for process drying. Generally, the hot water and low pressure steam produced by reciprocating engine CHP systems is appropriate for low temperature process needs, space heating, potable water heating, and to drive absorption chillers providing cold water, air conditioning, or refrigeration. They are well suited to a variety of distributed generation applications, industrial, commercial, and institutional facilities for power generation and CHP (UNEP, 2006).

One of the major advantages of reciprocating engines is their higher electrical efficiency as compared to other prime movers. Reciprocating engines start quickly, follow load well, have good part-load efficiencies, and generally have high reliabilities. However the maintenance costs are generally higher than comparable gas turbines. The two main types of internal combustion engines employed in cogeneration systems are diesel engines and otto engines.

3.4.5 Other possible prime mover options

Although most cogeneration systems are based on the prime movers already discussed, some other possibilities exist. Some cogeneration systems are based on fuel cells, photovoltaic and stirling engines. Most of these technologies are under development or near commercial applications (Chambers and Potter, 2002). Microturbines are also used in cogeneration systems. Although actually a sub-classification of gas turbines, since they represent a relatively new technology, they are often described as a separate category of prime mover.

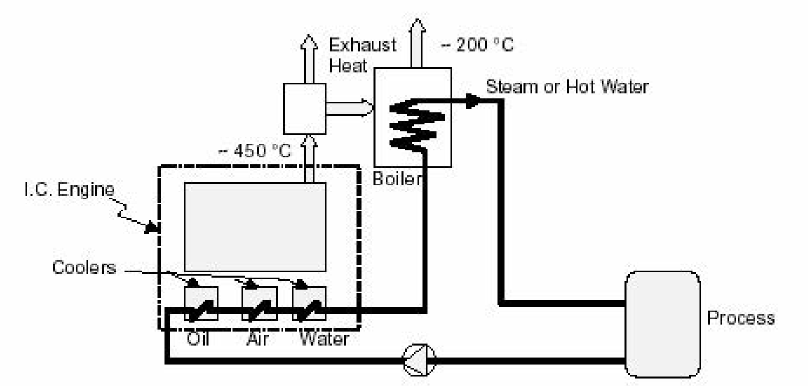

Figure 12 Reciprocating engine cogeneration system (UNEP, 2006)

3.5 Cogeneration Classification According to Sequence of Energy Use

Cogeneration systems can be classified according to the sequence of energy use in addition to the above categorization based on prime mover technology. There are two types of cogeneration systems based on the sequence of energy use: topping cycle and bottoming cycle.

3.5.1 Topping cycles

This is the most common type of cogeneration systems. In topping cycles, the fuel is first used to generate electricity or mechanical energy in a turbine generator and a portion of the waste heat from the power generation is then used to provide useful thermal energy for process heating or district heating. This cogeneration system is classified as topping cycle because the electrical power is generated first at the higher (top) temperatures associated with the fuel combustion process, and then, the rejected or exhaust energy is used to produce useful thermal energy (Caton, 2007). Topping cycle systems are generally found in facilities that do not have extremely high process temperature requirements.

3.5.1 Bottoming cycles

The less common bottoming cycle cogeneration systems first produce useful high temperature heat for a process via fuel combustion or another heat-generating chemical reaction and after the process hot gases are used either directly to drive a gas-turbine generator, if their pressure is adequate, or indirectly to produce steam in a heat recovery boiler, which drives a steam-turbine generator to generate electricity. After the energy is removed at the high temperatures, the energy available at the bottom or lower temperatures is then used to produce electrical power (Caton, 2007). Bottoming cycle cogeneration applications is most common in process industries, such as glass, steel and cement kiln that use very high temperature furnaces that would otherwise vent waste heat to the environment (C2ES, 2011).

3.6 CHP Sizing Concepts and Operation Modes

The size and operating strategy of a cogeneration system are normally selected to match as optimally as possible the thermal and electrical demands (Rosen, 2009). Apart from the market parameters such as prices and costs, the reliability and viability of CHP investments are determined from the correct dimensioning of the plants (Salta et. al, 2011). At the beginning of the project, a technical analysis in terms of energy savings and reasonable future expansion of an industrial unit should take place before their realization, so the CHP sizing would meet the real electricity and thermal needs of the unit. By sizing the cogeneration installations according to the electricity consumption of a unit, it is possible that the heat produced by cogeneration would exceed the real thermal needs of that unit. The extra heat produced is utilized onsite; if not, it is difficult to be stored or transported. Therefore, it is usually advisable that CHP installations be based on the heat demand of an industrial unit. In that way, the excess electricity produced, could be either sold to the utilities or transported to other users by making use of the grid (known as 'wheeling'). However, there are various modes of operation possible; the most distinct are (CRES, 2001 and BEE, 2005):

- **Thermal match mode:** The useful thermal output of a cogeneration system at any instant of time is equal to the thermal load (without exceeding the capacity of the cogeneration system). If the electricity generated is higher than the load, excess electricity is sold to the grid; if it is lower, supplementary electricity is purchased from the grid.
- **Base thermal load matching mode:** In this case, the cogeneration system is sized to supply the minimum thermal energy requirement of the site. Stand-by boilers or burners are operated during periods when the demand for heat is higher. The prime mover installed operates at full load at all times. If the electricity demand of the site exceeds that which can be provided by the prime mover, then the remaining amount can be purchased from the grid. Likewise, if local laws permit, the excess can be sold to the power utility.
- **Power match mode:** Under this operating strategy, the generated electricity at any instant of time is equal to the electrical load (without exceeding the capacity of the cogeneration system). All the power requirements of the site, including the reserves needed during scheduled and unscheduled maintenance, are to be taken into account while sizing the system. This is also referred to as a stand-alone system. The facility is totally independent of the power utility grid. If the co-generated heat is lower than the thermal load, an auxiliary boiler supplements for the

need; if it is higher, the excess heat is rejected to the environment through coolers or the exhaust gases.

- **Base electrical load matching mode:** In this configuration, the cogeneration plant is sized to meet the minimum electricity demand of the site based on historical demand curve. The rest of the needed power is purchased from the utility grid. The thermal energy requirement of the site could be met by the cogeneration system alone or by additional boilers. If the thermal energy generated with the base electrical load exceeds the plant's demand and if the situation permits, excess thermal energy can be exported to neighbouring customers.
- **Mixed-match mode:** In certain periods of time the thermal-match mode is followed, while in other periods the power-match mode is followed. The decision is based on considerations such as the load levels, the fuel price and the electricity tariff at the particular day and time.

In general, the thermal match mode results in the highest fuel utilization rate and perhaps the best economic performance for cogeneration in the industrial and building applications. For utility application, the mode of operation depends on the total network load, the availability of the power plants and the commitments of the utility with its customers regarding supply of electricity and heat. However, applying general rules is not the most prudent approach in cogeneration. Every application has its own unique characteristics; the design of a cogeneration system can be tailored to the need of the user. The design affects the possible modes of operation, and vice versa. Moreover, the technical and economic parameters may change with the day and time during the operation of the system. All these aspects make it necessary to reach decisions not by rules of thump only, but by systematic optimization procedures, based on mathematical programming (CRES, 2001).

3.7 Performance Parameters/Criteria of Cogeneration Systems

It is necessary to define certain criteria that reveal the thermodynamic performance of a cogeneration system and facilitate the comparison of alternative solutions. The most important of these criteria include:

- Efficiency of the prime mover

$$\eta_m^{chp} = \frac{\dot{W}_s}{\dot{E}_f} = \frac{\dot{W}_s}{m_f(LHV)} \qquad \textbf{(2.7.1)}$$

where

$\dot{W}_s$ is shaft power of the prime mover.

$\dot{E}_f$ is fuel energy input rate of the CHP plant.

m_f is fuel mass flow rate.

LHV is lower heating value of fuel.

- Electrical thermal efficiency

$$\eta_e^{chp} = \frac{\dot{W}_e}{\dot{E}_f} = \frac{\dot{W}_e}{m_f(LHV)} \qquad \textbf{(2.7.2)}$$

where

$\dot{W}_e$ is the net electric power output of the system, that is the electric power consumed by auxiliary equipment has been subtracted from the electric power of the generator.

- Heat efficiency

$$\eta_h^{chp} = \frac{\dot{Q}_u}{\dot{E}_f} = \frac{\dot{Q}_u}{m_f(LHV)} \quad (2.7.3)$$

where

$\dot{Q}_u$ is the useful thermal power output of the cogeneration system.

- Energy utilization factor (EUF)

A combined heat and power plant provides heat and generates electrical power. Hence one more logical criterion is the energy utilization factor (Horlock, 1987):

$$EUF = \frac{\dot{W}_e + \dot{Q}_u}{\dot{E}_f} = \eta_e^{chp} + \eta_h^{chp} \quad (2.7.4)$$

It must be remembered that work is difficult to produce and highly priced, whereas the useful heat is a lower grade, lower priced product from the plant. The energy utilization factor is thus therefore not entirely satisfactory as a criterion of performance as it gives equal weight to work and heat output of the plant.

- Artificial thermal efficiency (η_a)

An alternative criterion of performance sometimes used is an 'artificial' thermal efficiency (η_a) in which the energy in the fuel supply to the cogeneration plant is supposed to be reduced by that which would be required to produce the useful heat (Q_u) in a separate 'heat only' boiler of efficiency η_B, i.e. by $\dot{Q}_u / \eta_B$. The artificial thermal efficiency is then given by

$$\eta_a = \frac{\dot{W}_e}{\dot{E}_f - \left(\dot{Q}_u / \eta_B \right)} = \frac{\eta_e^{chp}}{1 - \left(\frac{\dot{Q}_u}{(\eta_B \dot{E}_f)} \right)} \quad (2.7.5)$$

where η_e^{chp} is the electrical thermal efficiency of the CHP plant. Artificial thermal efficiency is easily accepted because it is in the form of thermal efficiency. However, the artificial thermal efficiency is also not a reasonable criterion as it gives equal weight to the useful heat at different temperatures (Feng et al., 1998).

- Heat-to-power ratio (λ_{chp})

For any prime mover/electrical generator used in a cogeneration plant, there is a balance between the electrical power that can be generated and the useful heat that can be recovered. This is generally referred to as the heat to power ratio and is expressed as the quantity of heat recovered per unit of electricity generated.

$$\lambda_{chp} = \frac{\dot{Q}_u}{\dot{W}_e} \quad (2.7.6)$$

The heat to power ratio is a useful way of assessing the suitability of a CHP generator for a particular site (DECC, 2012).

- Fuel energy savings ratio (FESR)

Another performance criterion developed for cogeneration plant involves comparison between the fuel energy required to meet the given load of electricity and heat in the CHP plant with that required in separate conventional plants to meet the same loads, say in a separate conventional electric power station of electrical thermal efficiency η_e and a 'heat only' boiler of efficiency η_B. Then the fuel energy saved is

$$\Delta \dot{E}_f = \frac{\dot{Q}_u}{\eta_B} + \frac{\dot{W}_e}{\eta_e} - \dot{E}_f \qquad (2.7.7)$$

and the fuel energy savings ratio (FESR) is defined as the ratio of the saving ($\Delta \dot{E}_f$) to the fuel energy required in the conventional plants. Hence,

$$FESR = \frac{\Delta \dot{E}_f}{\left(\frac{\dot{Q}_u}{\eta_B} + \frac{\dot{W}_e}{\eta_e}\right)} = 1 - \frac{\eta_e / \eta_e^{chp}}{\left[1 + \left((\lambda_{chp}\eta_e) / \eta_B\right)\right]} \qquad (2.7.8)$$

where λ_{chp} is the useful heat to power ratio of the CHP plant. This thermodynamic criterion of performance is perhaps the most useful yet described as it can be used directly in economic assessment of cogeneration plant (Horlock, 1987).

- Exergetic efficiency (Ψ^{chp})

It is probably not proper to add electricity and heat and hence a comparison between systems based on the energy efficiency may be misleading sometimes. Even though energy efficiency or first law efficiency are most commonly used, a thermodynamically more accurate evaluation and a more fair comparison between systems can be based on exergy efficiency or second law efficiency. The use of exergy in assessing cogeneration system is highly advantageous. Exergy methods allow the value of cogeneration products to be compared on a similar basis, whereas the more conventional energy methods treat heat and electricity the same. The exergetic efficiency can be defined as the ratio of total exergy output to exergy input:

$$\Psi^{chp} = \frac{Ex_{out}}{Ex_{in}} = \frac{\dot{W}_e + \dot{Ex}_h}{\dot{Ex}_f} = \frac{\dot{W}_e + \Phi \dot{Q}_u}{R \dot{E}_f} \qquad (2.7.9)$$

where

Ex_{out} is the total exergy output of the system

Ex_{in} is the total exergy input to the system

$\dot{Ex}_h$ is the exergy rate associated with the transfer of useful heat, $\dot{Q}_u$

$\dot{Ex}_f$ is the exergy rate associated with the energy flow rate of the fuel, $\dot{E}_f$

Φ is the exergetic temperature factor for $\dot{Q}_u$

R is the energy grade function of the fuel

4.0 Feasibility of HTR Cogeneration Secondary System Coupling to Industrial Processes

In October1956, the world's first commercial-scale nuclear power reactor came into operation at Calder Hall in the United Kingdom. The plant provided electricity to the grid and heat to a neighbouring fuel reprocessing plant for about 46 years of it operation. In Sweden, the Agesta reactor provided hot water for district heating to a suburb of Stockholm for a decade, starting in 1963. In 2011, out of about 432 nuclear power reactors worldwide about 74 had been used for cogeneration of hot water and/or steam for district heating, seawater desalination or industrial processes (Khamis, 2011). Over 700 reactor-years of combined experience exist for these non-electrical applications. These examples show the potential of nuclear power reactor to deliver heat for industrial processes and urban needs. Such applications started at a very early date, practically at the same time when nuclear power reactors were first applied to electricity generation. Hence the technical viability of employing nuclear heat sources for district heating and industrial processes has existed since the very start of nuclear development (Csik and Kupitz, 1997). However, a substantial penetration into the commercial heat market is yet to take place.

The prospects of nuclear process heat application will depend, among other things, on the matching of the demand characteristics of the heat market with what nuclear reactors are able to offer. However, high-temperature nuclear reactors (HTRs) enable a range of applications not previously available to the nuclear industry, including a number of process industry applications. Developers of HTR worldwide acknowledge that it creates a number of new opportunities due to its unique ability to address growing needs for industrial cogeneration of heat and power. These opportunities are based on (Kuhr, 2008; and Angulo et al., 2012): (1) The HTR high operating temperatures and flexibility (2) The small reactor size (400-600 MWt) matches industrial plant sizes for any applications where the market offers incremental process heat demands in that range (3) The enhanced safety features allow siting close to process plants (4) The simpler design of an HTR heat plant results in a smaller footprint than a larger conventional nuclear power generating facility and facilitates site and flow sheet integration.

Development programmes on the high-temperature nuclear reactor have been ongoing for more than 40 years in a number of countries. The concept of the high-temperature gas-cooled reactor (HTGR) evolved from the Magnox reactors (with carbon-dioxide cooling). The basic technology for the HTR has been well established in former High Temperature Gas Reactors plants, such as the DRAGON in the UK, the US Fort-Saint-Vrain and Peach Bottom prototypes, and the German AVR and THTR prototypes (Carre, 2010). Today, the technical feasibility and the advantages of this reactor concept for electricity generation and process-heat applications have been demonstrated by experimental and demonstration reactors in Germany, the United Kingdom, France, Japan, Korea, China, South Africa and the United States (Kupitz and Dee, 1984). As shown in Figure 13, the technology has been and is being advanced through several research projects such as (Hittner, 2006; Baxi et al., 2006; and Carré et al., 2009):

- The High Temperature engineering Test Reactor (HTTR) and the Gas Turbine High Temperature Reactor 300-Cogeneration (GT-HTR300C) in Japan.
- The HTR-10 and the High Temperature Reactor-Pebble bed Module (HTR-PM) in China.
- The Pebble Bed Modular Reactor (PBMR) in South Africa.
- The Next Generation Nuclear Plant (NGNP) project in the United States.
- Nuclear Hydrogen Development and Demonstration (NHDD) project in the Republic of Korea.
- The General Atomics Gas Turbine-Modular Helium Reactor (GT-MHR) developed jointly by Russian and American institutes under the auspices of the Russian and the U.S. Department of Energy.
- ANTARES (Areva New Technology based on Advanced gas-cooled Reactor for Energy Supply) in France.

As highly efficient advanced nuclear systems, HTR cogeneration systems can be considered in a variety of configurations for electricity generation and process heat applications (Tsvetkov et al., 2010). However, no HTR has yet been coupled with any industrial process (Gauthier et al., 2007). But their potential to provide, besides electricity, high temperature process steam and process heat for various industrial applications has been, together with high safety margins, the continuing incentive for further

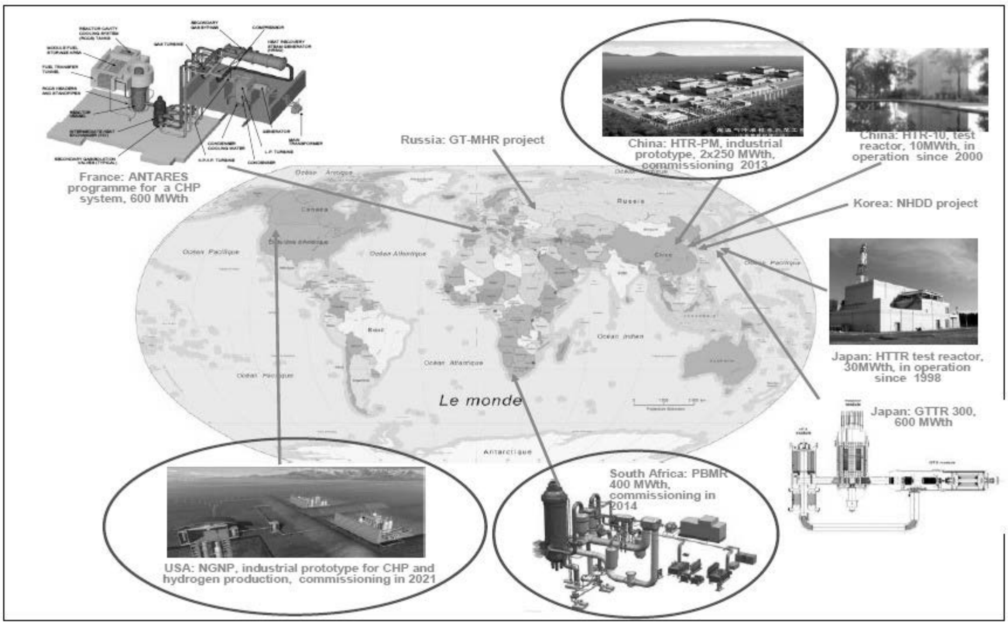

Figure 13 Status of HTR development in the world (Carré et al., 2009)

development (Kupitz and Dee, 1984). In 1996, a joint working group in The Netherlands carried out a pre-feasibility study of the conceptual design of an Inherently safe Nuclear COGENeration (INCOGEN) with a 40 MW thermal pebble bed HTR (Jehee, 1997). The concept was later improved to produce industrial quality heat and renamed ACACIA, which is an acronym for AdvanCed Atomic Cogenerator for Industrial Applications (Haverkate et al., 1998). During these studies, technical and economic feasibilities of a 40 MW thermal cogeneration unit were shown. However, nuclear cogeneration for industrial process heat applications is a major innovation requiring large-scale demonstration to prove its industrial viability. The most convincing argument for potentially interested end-users is probably the successful demonstration of nuclear cogeneration technology at a relevant production scale. To enable demonstration, it is necessary not only to develop an appropriate nuclear heat source, but also to develop coupling technologies and to adapt industrial processes to the coupling with a HTR (Hittner et al., 2011). In line with this, the European High Temperature Reactor Technology Network (HTR-TN), in continuation of its previous programmes for developing HTR technology, initiated the EUROPAIRS (End-User Requirements fOr industrial Process heat Applications with Innovative nuclear Reactors for Sustainable energy supply) project and presently ARCHER (Advanced High-Temperature Reactors for Cogeneration of Heat and Electricity R&D), which is the subject of the present study. In EUROPAIRS, experts from the nuclear industry and those from large energy/heat consuming industries were brought together to evaluate the feasibility of coupling HTR with industrial processes as one of the core pillars of the project (Angulo et al., 2012). Major achievements have been obtained regarding the boundary conditions and the needed technical requirements for selecting the design options for the coupling of HTR with end-user's industrial processes.

Apart from the technical feasibility of the HTR cogeneration systems, other equally important requirements include the industrial heat demand compatibility, economic feasibility, as well as safety and licensing requirements.

4.1 Industrial Heat Demand Compatibility

The industrial process heat market is highly fragmented in nature because of the very large variety of applications with different heat requirements and with temperature ranges covering a wide spectrum. How far and how fast HTR cogeneration system could capture part of this market will depend mainly on how the characteristics of nuclear reactors can be matched with the characteristics of the heat market, in order to successfully compete with alternative energy sources. The quantity, supply rate and temperature of supplied heat must satisfy all demand requirements and, in addition, the system must be able to accommodate actual variations in heat-demand parameters (quantity, temperature, etc.). Based on the analyses of both energy needs of end-users and characteristics and limitations of the HTR heat supply, the capabilities of the nuclear system and the requirements of industrial processes can be matched to identify common operating windows in which coupling is feasible (Angulo et al., 2012).

EUROPAIRS brought together 13 different end-users, engineering companies and research centres which shares information on larger-scale production processes. According to the data collected on different processes, three main classes of process families with different development needs and different level of development risks were proposed (Angulo et al., 2012; and Hittner et al., 2011):

- **Steam class:** This extends from 150 ˚C to approximately 600 ˚C and includes processes using steam as the heat transport and heating media. Examples are: the distillation unit in a refinery, district heating, drying processes, power generation in steam turbines and desalination by multi-stage flash evaporation.
- **Chemical class:** In this case heat is the driver of chemical reactions and is consumed as reaction enthalpy at constant temperature. The process temperature lies between 600 ˚C and 900 ˚C. Examples are: oil derivatives; methane, biomass and coal derivatives.
- **Mineral class:** In this processes, heat is used to melt solid or to drive reactions between solids. The temperatures required are usually above 900 ˚C. Examples are: metal processing industries, ceramics industries and cement manufacturing processes.

In Figure 14, the temperature range required in present major large scale process heat intensive industrial uses is shown as well as the range of temperature of the heat source that can be provided by nuclear reactors both today and in the near term with a reasonable development based on existing technologies and materials. The HTR concept covers almost the whole temperature range and is therefore considered as being a leading candidate for the supply of nuclear process heat (IAEA, 2002). The development and demonstration of an HTR with a relatively small capacity would provide a strong impetus for process heat applications.

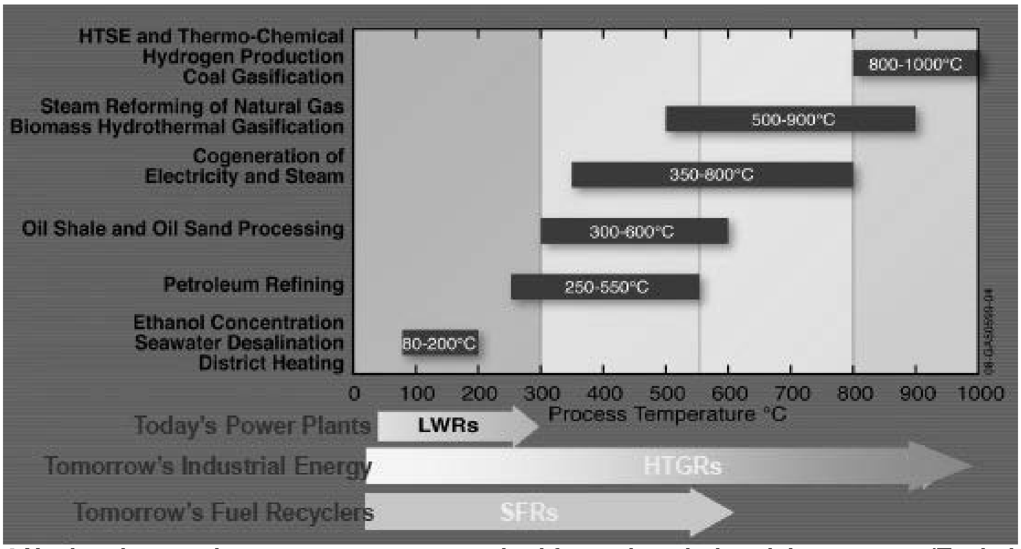

Figure 14 Nuclear heat and temperature range required for various industrial processes (Tyobeka, 2011)

Based on the modular concept of HTR, the nuclear cogenerating reactors may be suited to support process heat markets since their smaller sizes align well with the capacity requirements of process industries. The HTR cogeneration plant may consist of multiple reactor modules to respond to a variety of power demand of industrial sites thereby providing the end-user with more flexibility to match load growth and to manage possible outages. Also since the availability and reliability of an HTR reactor can never reach the 100% levels required by most large heat user, the multiple unit cogeneration power plants, modular designs for back-up heat sources are suitable solutions (Csik and Kupitz, 1997).

4.2 Technical Feasibility

In principle, no technical impediments to coupling nuclear reactors to industrial process applications have so far been observed; although a number of safety-related studies of coupled systems may still be advised (IAEA, 2002). HTR technology has already a long historical background with several HTR experimental reactors and operational demonstrators all over the world. The nuclear industry has gained invaluable experience from these past realisations giving them confidence that the HTR technology could be considered mature (Angulo et al., 2012). However what is left to be demonstrated is the coupling of these HTRs to industrial processes for the cogeneration of electricity and heat. But studies and conceptual designs has been carried out to demonstrate the technical feasibility of HTR cogeneration through the elaboration of the coupling schemes for optimum cogeneration of electricity and heat by exploring the unique capabilities of the innovative HTRs and industrial processes. The joint INCOGEN (Inherently safe Nuclear COGENeration) study of five Dutch nuclear research groups concluded that an HTGR cogeneration plant was technically feasible (Kikstra and Verkooijen, 2000). Also a design study of the ACACIA indirect cycle plant concluded that all major equipment can be obtained based on available experience or from off-the-shelf products (da Cruz et al., 2003**)**. The HTRs attributes provide for a high temperature capability that is unique among established reactor concepts. These much higher operating temperatures enable higher efficiency of power conversion of HTRs, particularly in cogeneration mode.

The aim to build a demonstration plant in the near future requires that only mature technologies can be used. From the analyses of both industrial processes and heat transfer technology for HTR heat supply, it seems obvious that steam cycle coupling for process steam production and electricity generation such as shown in Figure 15 would be the most appropriate scheme for a near-term demonstration plant. A coupling scheme with steam as heat transfer medium would be a first step with significant impact on the energy landscape. With existing or near-term technology, HTR can deliver process steam at temperatures up to 600 ˚C. Design of dedicated steam generators would require limited developments as there is already a market for process steam and the technology is already used in most realizations of LWR and gas-cooled reactors. Furthermore, boilers in general are widely used in the industry and much information is available on aging mechanisms but steam generator design with helium has to be further optimized. The process steam market that would be accessible to HTR supply in the near term already represents a considerable fraction of the potentially achievable CO_2 emission reduction potential. Hence, the steam cycle HTR concept will reduce technology development and project risk as well as minimize the delay before a useful contribution to the process steam sector of the energy economy can be realized. It also provides a stepping stone to longer term very high temperature concepts which might serve additional markets belonging to the chemical class i.e. at temperatures between 600 ˚C and 900 ˚C. The use of less mature technology such as that required for the VHTR necessitates additional R&D which entails both extended schedules and increased risk and uncertainty. This also further complicates the design and licensing activities.

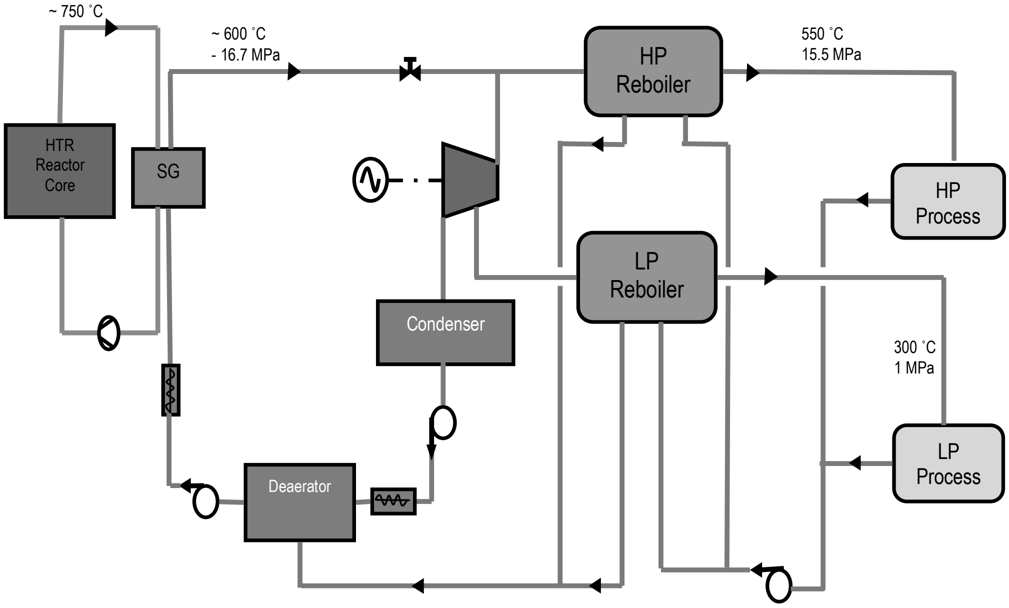

Figure 15 Example of a near-term steam cycle HTR cogeneration plant configuration

4.3 Economic Feasibility

Economic feasibility is a crucial issue that has to be considered in parallel to technical arguments. Nuclear reactors can be technically proven, safe, reliable and environmentally clean energy sources, but for commercial deployment they also have to be economically competitive with alternative energy sources (Csik and Kupitz, 1997). Full data needed for economic analysis or market assessment is not publicly available yet for small nuclear cogenerating reactors (Carlsson et al., 2012). However, plant economics will inevitably be a key determinate of their viability. The main factors that would improve the competitiveness of nuclear options for cogeneration include lower specific overnight costs, shorter construction times, lower discount rates, the incorporation of environmental externalities in the price of energy and the expectation of increasing fossil fuel prices (IAEA, 2002).

According to Baaten (2011), preliminary economic evaluations indicate a credible future window of opportunity for HTR. In the cost analysis by van Heek et al. (2004), the energy conversion system makes up only 10% of the capital investment cost. Carlsson et al. (2012) used parametric analysis to create a cost breakdown (capital, operations and maintenance, fuel, and decommissioning) for an equivalent nuclear CHP that could compete against coal-CHP and natural gas-CHP. Sensitivity analysis showed that reactor capital costs and the costs of capital had the largest influence on competitiveness. In summary, the opportunities for nuclear CHP are highest in natural gas-CHP markets; however the benefits for CO_2 reduction were greatest against coal-CHP. The inclusion of externalities such as environmental costs can substantially increase the economic competitiveness of nuclear cogeneration, and that for policy reasons (e.g., environmental), nuclear cogeneration alternatives may be considered even if the specific application is not economically competitive. Haverkate et al. (1998) carried out cost estimates for an Nth-Of-A-Kind (NOAK) 40 MW nuclear CHP system based on cost data for the South African conceptual PBMR-design. Comparing the economic figures obtained with the production cost of an equally sized natural gas fired CHP unit indicated that the nuclear CHP unit entered the competitive area.

Based on the modular concept, a nuclear cogeneration plant may consist of multiple reactor modules to respond to a variety of power demand of industrial sites (e.g. electricity, heat, steam etc.) This approach results in cost advantages from a modular design and construction approach. Unlike traditional nuclear plants that need economy of scale to become economic plants, the small HTR nuclear plants use the modular design concept to be able to compete in a market (da Cruz et al., 2003). This offers several advantages. Capital cost per unit (and therefore financial risk) is lower and therefore decisions to build further units are less fraught with risk and complication. Series production of the components will bring down costs as well. Maintenance outages can be spread over the year and will not fully interrupt power production on the site. Also series production is possible through application of identical units on many different sites. The modular high temperature system is associated with limitations on power level and power density allowing the development of a reactor concept favouring passive safety characteristics. Such simplification entails saving in initial investment. By designing the reactor in such a way that certain components become superfluous, the economic cost can therefore be reduced. Furthermore, many of the process heat users, in particular the large ones, can be and usually are located outside urban areas, often at considerable distances. This makes joint siting of nuclear reactors and industrial users of process heat desirable in order to drastically reduce or even eliminate the heat transport costs.

4.4 Safety and Licensing Requirements

In parallel to the technical and economic viability of HTR cogeneration system, safety and licensing issues arising from the coupling of the HTR with the heat process is also crucial. The events on one plant of the coupling (nuclear or heat process) has the tendency to impact the other plant. The specific risk that could arise from the coupling has to be identified in order to determine the acceptance criteria for the feasibility of the licensing of the coupled system. The main requirement to ensure the safety assessment feasibility is that the safety of the nuclear plant shall not be negatively influenced by the coupling in comparison with stand-alone current nuclear installations (Angulo et al., 2012).

The designers of HTR systems base their safety demonstration on the reactor-inherent physical characteristics and on the use of passive safety systems for keeping the reactor in safe conditions and with negligible release of radioactive products to the environment during operation. Furthermore, the extremely low radiological consequences level due to the small power level and power density of HTR means that the emergency planning zone may be limited to the footprint of the plant site. These safety characteristics are a significant advantage for process heat applications where the reactor module may be sited in close proximity to the chemical plant or other process heat user. With such safer reactors and simpler design, the easier operation and also the easier people's understanding on safety become feasible (Tsuchie, 2000).

One of the items reviewed by EUROPAIRS is related to potential contamination of the heat transport circuit between reactor and end-user by radioactive elements in general and tritium in particular (Angulo et al., 2012). The direct coupling between the secondary circuit and the heat process presents the advantage to be very simple. However, it might not be acceptable from the point of view of tritium release and the contamination of equipment of the end-users. Indeed, several technical measures help to reduce radioactive contamination of this circuit below currently applicable effluent limits. Potential radioactive contamination of the heat transport networks or of the products obtained by the industrial processes can be avoided by the addition of intermediate (tertiary) heat exchanger circuits which act as effective barriers (Csik and Kupitz, 1997). Moreover, the tertiary circuit reduce the amplitude of the transients generated by events on the heat process side.

5.0 Design and Cycle Analysis of the Demonstration Plant

The HTR cogeneration demonstration plant secondary system is designed and the main components pre-sized based on information gathered from the primary side (nuclear reactor side) and from the industrial process side, using the information from previous cogeneration related programmes, EUROPAIRS and the other tasks in this ARCHER project. The nuclear reactor selected for the analysis is assumed to be sized to produce 600 MW of thermal power, with a target core outlet and inlet temperatures of about 750 ˚C and 325 ˚C respectively. However, the details of the reactor primary side are not shown in this analysis. On the industrial process side, the demonstration plant is configured to deliver both electricity and process steam at two pressure levels at temperatures up to 550 ˚C.

The proposed design options of the coupling schemes for the HTR cogeneration demonstration plant can be broadly categorised into:

- HTR-Steam cycle cogeneration concept (with or without reheat).
- HTR-Gas turbine cycle cogeneration concept.
- HTR-Combined cycle cogeneration concept.

5.*1 HTR Steam Cycle Cogeneration Configuration*

This is regarded as probably the most suitable near term coupling option for cogeneration of heat and electricity from high temperature nuclear reactor. It helps to reduce extensive development in the power conversion system based on past experiences with conventional steam cycle. Therefore it should lead to an earlier deployment than technologies requiring extensive developments. The HTR-steam cycle concept minimizes any impact of technology development on the project schedule and the added risk that this development would impose on other elements of the project schedule.

5.1.1 Cycle layout and description

The cycle configuration for the HTR steam cycle cogeneration concept is shown in Figure 16. The nuclear heat source is coupled to the steam cycle through the steam generator, thus establishing the basis for a common heat source design and minimising the development challenges associated with the reactor and primary heat transport system (Gauthier et al., 2006). The cycle consists of a steam generator, 2 steam expansion stages (high and low pressure turbines), one condenser, a total of 5 surface feedwater heater (FH), one de-aerator, and 2 reboilers (for high and low pressure process steam supply). The steam generator (including an economiser, evaporator, and superheater) transfers energy to the secondary steam side. The steam side can produce both electricity, via the turbine and generator set, and process heat via the reboilers. The reboilers provide steam on the tertiary side to supply heat to an industrial process hence satisfying the safety requirement of minimum two barriers between the reactor and the industrial process. This provides protection against potential carry-over of radioactivity to the process side. High pressure (HP) and low pressure (LP) reboilers provide process steam to process heat applications over a wide operating range.

The high pressure steam flowing out of the steam generator is split in two fractions; one is supplied to the high pressure turbine (HPT) and the other acts as the heat source in the high pressure (HP) reboiler. Steam is extracted at an intermediate point in the HPT to feed the low pressure (LP) reboiler. Both streams from the HP and LP reboilers are mixed-up before entering the de-aerator where they combine with the other streams. The feedwater is heated in the feedwater heaters before it enters the steam generator by steam bled from the turbine at selected stages. Feedwater is pressurized in two steps, from the condenser to de-aerator pressure by the condensate pump and from de-aerator to the steam generator pressure by the feedwater pump. The de-aerator provides a convenient mean of deaerating the feed-water to prevent corrosion of the steam generator.

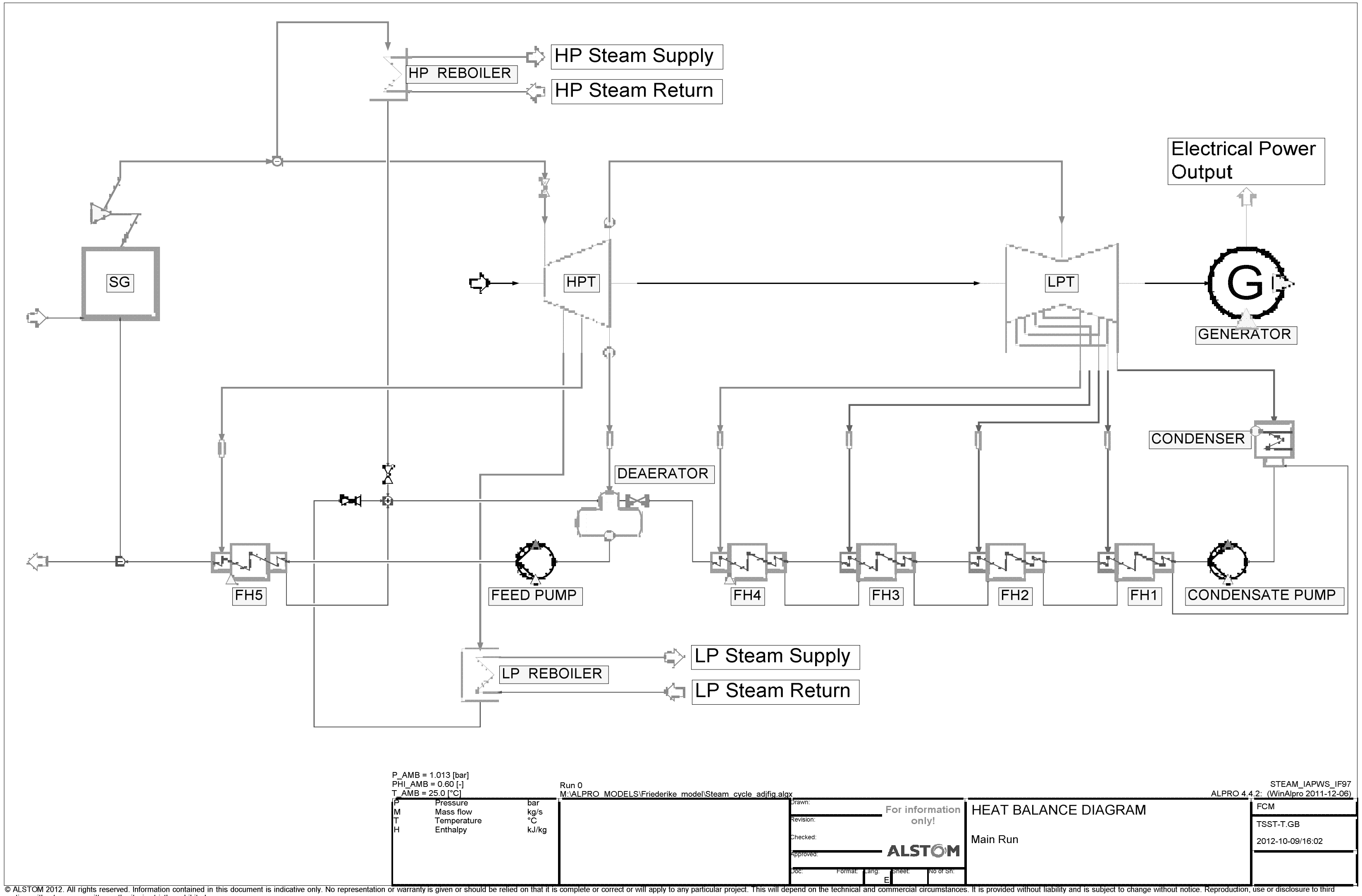

Figure 16 HTR steam cycle cogeneration layout

5.1.2 Assumptions and design parameters

An ALPRO steady-state heat balance model was developed for the demonstration plant to gain insight into cogeneration plant configuration. The following assumptions and simplification have been made for the model:

- The steam generator is assumed to have an efficiency of 90% hence only 540 MW out of the 600 MW reactor power is transferred to the steam cycle.
- The high pressure and low pressure turbines have been considered with constant isentropic efficiencies of 89% and 90% respectively.
- Pumps have been considered with constant isentropic efficiencies of 75%.
- 98% efficiency for the generator.
- 10% pressure drop in the steam generator.
- Reboilers are modeled as heat exchangers consisting of economizers, evaporators and superheaters.
- 0.7% pressure drops on both the hot and cold side of the reboilers economizer, evaporator and superheater.

The design parameters selected for the analysis are:

- Design thermal power input to the steam generator of 600 MWth.
- 241 ˚C steam generator inlet temperature.
- 600 ˚C steam generator outlet temperature.
- 16.7 MPa steam generator outlet pressure.
- Condenser pressure of 0.0045 MPa.
- Cooling water supply: 0.1013MPa (1.013 bar), 16.3 ˚C.
- De-aerator pressure: 1.76 MPa (17.6 bar)
- Process steams return temperature of 50 ˚C.
- High pressure process steam supply: 15.5 MPa and 550 ˚C.
- Low pressure process steam supply: 1 MPa and 300 ˚C.

5.1.3 Cycle performance

The cycle can be designed for different values of HP and LP process steam flow rate (i.e. reboilers cold side flow) depending on the desired mix of process heat/electricity production. However the maximum steam flow rate possible would be constrained by the thermal power. A specific design case of 50 kg/s (180 tonnes/hour) process steam flow rate each from the HP reboiler and LP reboiler is considered for the purpose of analysis. The HP reboiler supply process steam for industrial application at a pressure of 15.5 MPa and 550 ˚C temperature while the LP reboiler supply steam at 1 MPa and 300 ˚C. The return flow from the industrial process to the reboilers is at a temperature of 50 ˚C.

The cycle configuration showing the state points and characteristic values of some of the main components is shown in Figure 17. The useful heat transferred in HP reboiler and LP reboiler is about 161 MW and 142 MW respectively and about 106 MW is evacuated to the heat sink via the condenser. Electrical power output of the generator is 130 MW. The energy saving is evaluated by comparing the HTR cogeneration system to a system separately producing equivalent amount of process heat and electricity in a nuclear steam generator and HTR nuclear power plant respectively. The separate steam generator is assumed to have an efficiency of 90% and an efficiency of 40% is assumed for the power generating plant (see Table 2). A summary of the characteristic values and overall performance of the HTR steam cycle configuration is shown in Table 3. The ratio of the useful heat to electrical power delivered to the industrial process is about 2.33. Electrical efficiency of the cogeneration system is about 21%. However, a thermal energy saving of about 7% is achieved. The energy utilization factor (or net thermal efficiency) is about 72% compared to 67% calculated for the separate production option.

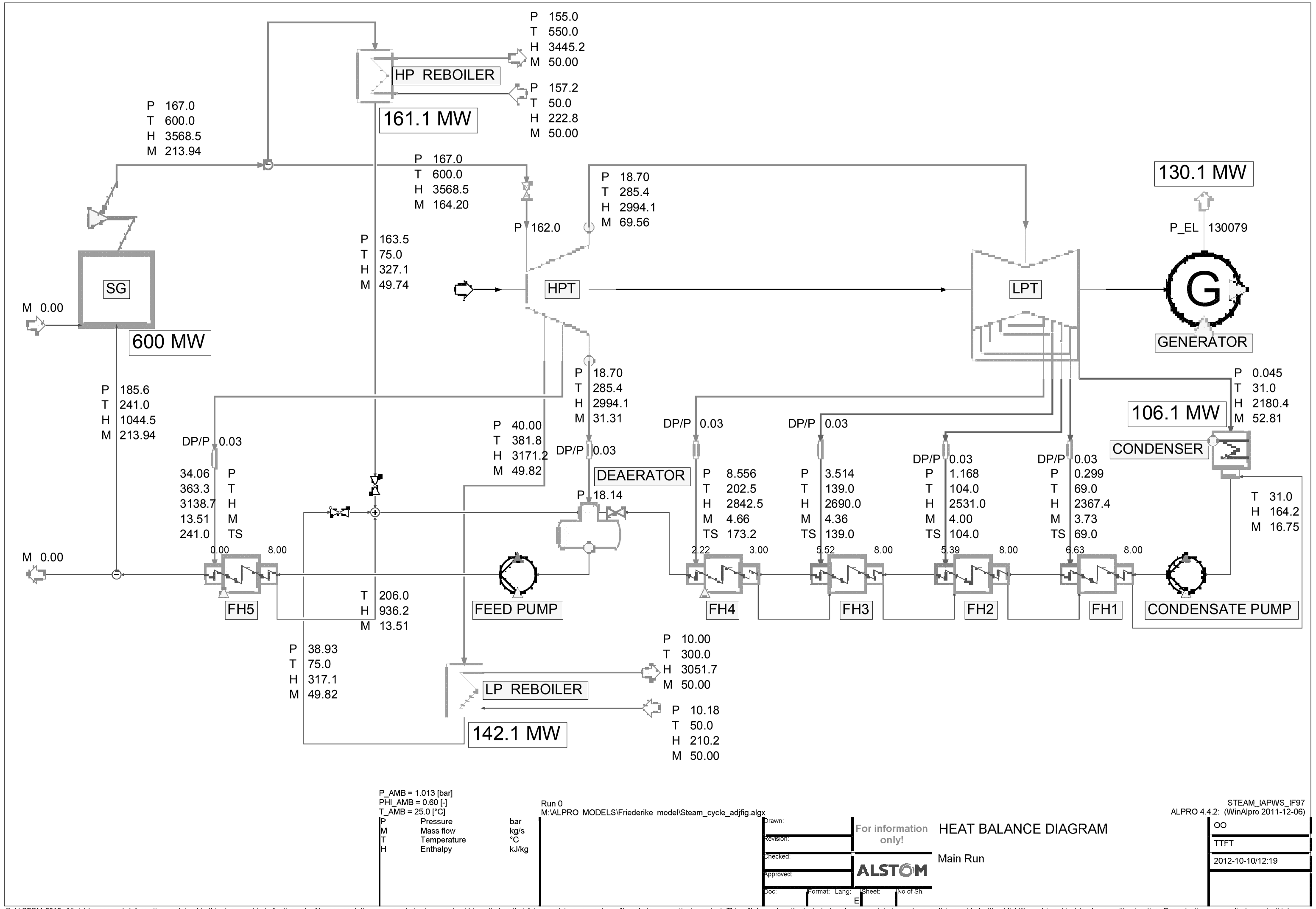

Figure 17 State points and component characteristic values

Table 2 Separate production of electricity and heat

Parameters	Units	Values
Steam Generator Efficiency	-	0.9
Power Plant Efficiency	-	0.4
Total Process Heat	MW	303
Electrical Power	MW	130
Steam Generator Thermal Input	MW	337
Power Station Thermal Input	MW	311
Total Thermal Input	MW	648
Energy Utilisation Factor (EUF)	-	0.67

Table 3 Summary of results of cogeneration cycle calculations

Parameters	Units	Values
Steam Generator		
Input Thermal Power	MW	600
Operating Pressure	MPa	16.7
Steam Inlet/Outlet Temperatures	˚C	241/600
Steam Mass Flow	kg/s	213.94
HP Heat Cogeneration		
Steam Inlet/Outlet Temperature	˚C	50/550
Steam Pressure	MPa	15.5
Steam Mass flow	kg/s	50
Transferred Heat	MW	161
LP Heat Cogeneration		
Steam Inlet/Outlet Temperature	˚C	50/300
Steam Pressure	MPa	1
Steam Mass flow	kg/s	50
Transferred Heat	MW	142
Generator		
Electrical Power Output	MW	130
Overall Performance		
Heat to Power Ratio	-	2.33
Prime Mover Efficiency	-	0.22
Electrical Thermal Efficiency	-	0.21
Heat Efficiency	-	0.51
Energy Utilisation Factor (EUF)	-	0.72
Artificial Thermal Efficiency	-	0.47
Exergy Efficiency	-	0.43
Fuel Energy Saving Ratio (FESR)	-	0.07

5.1.4 HP and LP reboilers

One of the unique features of this configuration is the inclusion of reboilers. Instead of using bled steam from the secondary steam cycle to directly transfer heat to the industrial process; reboilers were introduced between the secondary cycle and the industrial process. The reboilers are heat exchangers consisting of economizer, evaporator and superheater. The vapour extracted from the steam generator outlet or from one of the turbine stages is fed to a heat exchanger (i.e. reboiler) where the process return water is raised to an appropriate level. The high pressure reboiler delivers high temperature superheated steam while the low pressure reboiler delivers low temperature superheated steam for industrial application. The heat exchangers help to increase the safety barrier between the primary reactor circuit and the industrial process and hence reduce the possibility of carry-over of radioactive contaminants to the process side. Also the extra heat exchangers reduce the potential for severe reactor transients induced by transients in the industrial process, either during normal operation or as a result of non-availability of industrial plant.

5.1.5 Design for various process steam supply rates

A range of design conditions was considered from all electric to all process heat production by varying the flow rate to process heat system. For both the HP and LP reboilers, the process steam flow rate was increased from nearly zero (almost 100% electricity production i.e. zero heat to power ratio) to a near maximum flow rate (almost 0% electrical output i.e. maximum heat to power ratio). Design points with process steam production rates up to 75 kg/s each from the HP and LP side were achievable corresponding to a maximum heat to power ratio of about 6.94. The changes in cycle performance for the different design conditions (heat to power ratio) are presented in Figure 18, Figure 19, Figure 20, Figure 21, Figure 22, Figure 23, Figure 24, Figure 25, Figure 26 and Figure 27. The increase in process steam flow rate will result in decrease of electrical power output and consequently lower electrical thermal efficiencies as shown in Figure 18. Results indicate that there is a trade-off between process steam and electricity production. For pure electricity production (zero heat to power ratio) a thermal efficiency of about 40% is achieved. Figure 19 shows that energy utilisation factor increases with heat to power ratio and the values for the cogeneration system is always above that of separate units for values of heat to power ratio above zero. The thermal energy savings is also seen to increase with the heat to power ratio as indicated in Figure 20. Figure 21 and Figure 22 show the changes in the artificial thermal efficiency and exergy efficiency for the different design points. However, the HP steam production rate has little effect on the energy saving ratio as Figure 23 shows. Also Figure 24, Figure 25, Figure 26 and Figure 27 show the individual impacts of HP and LP steam production rates on the thermal efficiency, energy utilisation factor, exergy efficiency and artificial thermal effeciency of the cogeneration system. Both HP and LP process steam delivery rate is seen to have almost equal effects on these cycle performance parameters.

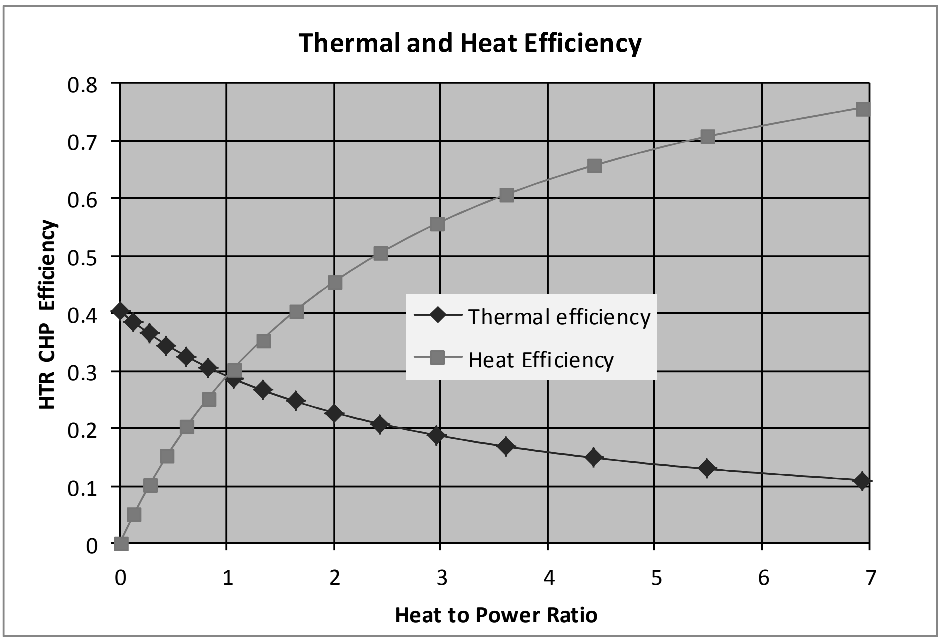

Figure 18 Electrical thermal efficiency and heat efficiency as a function of heat to power ratio

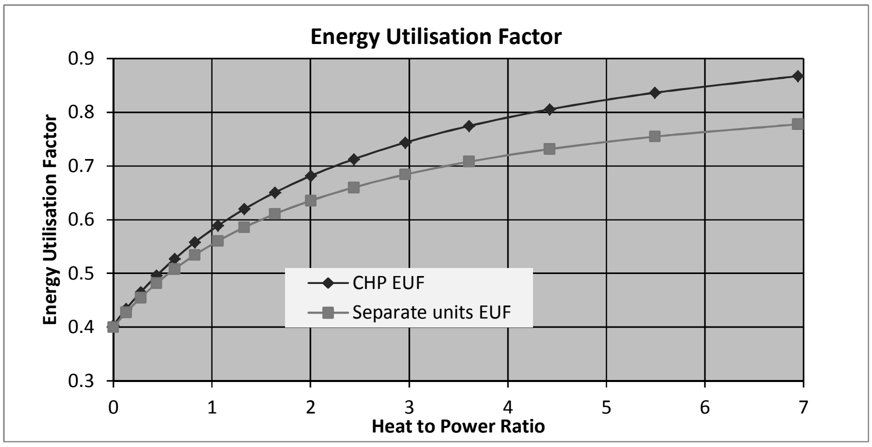

Figure 19 Energy utilization factor as a function of heat to power ratio

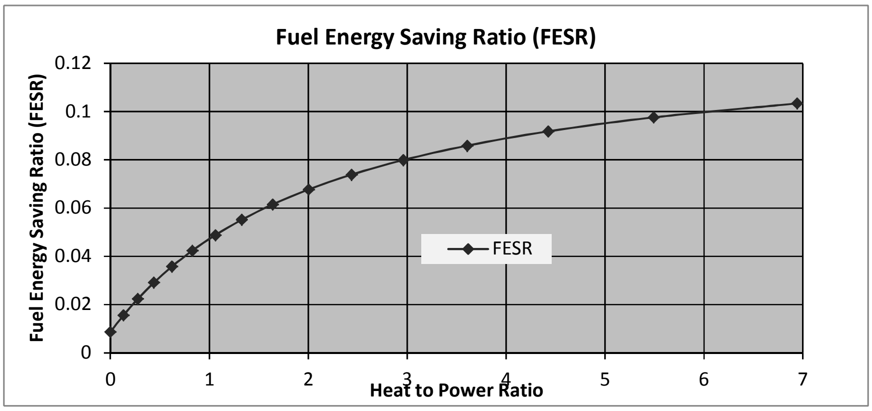

Figure 20 Fuel energy saving ratio as a function of heat to power ratio

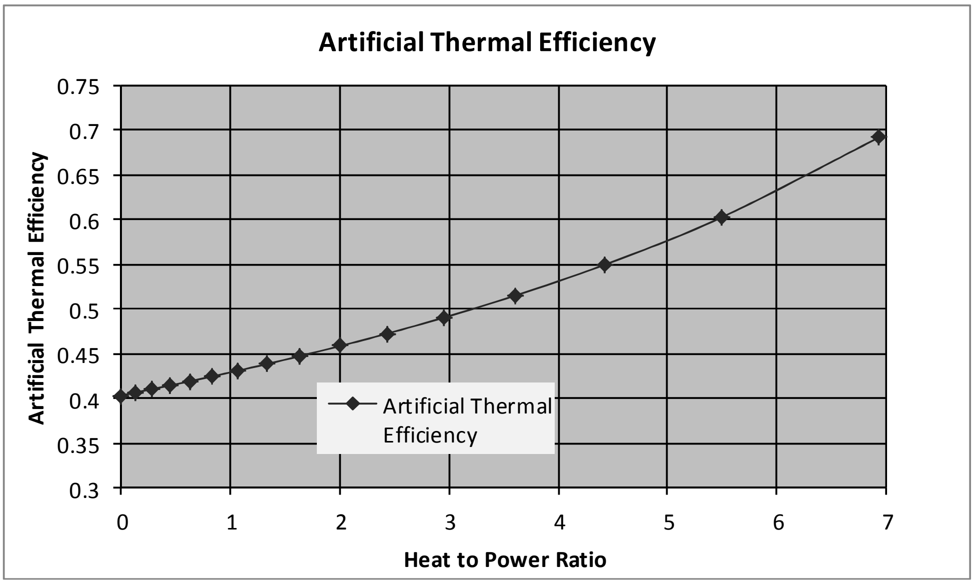

Figure 21 Artificial thermal efficiency as a function of heat to power ratio

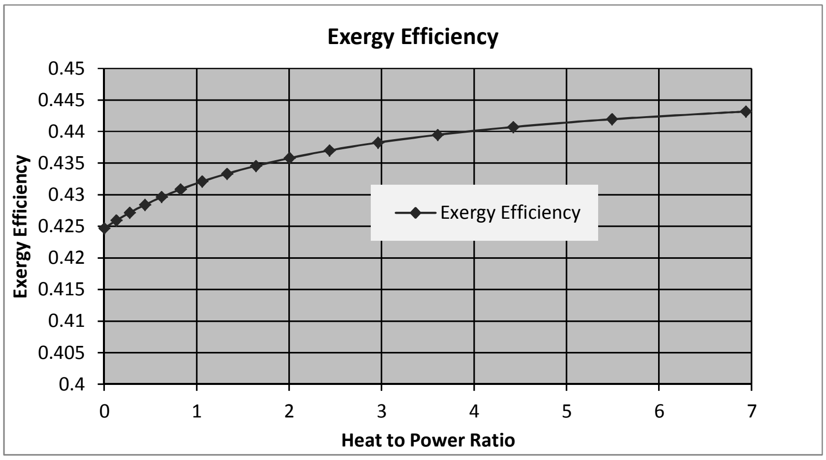

Figure 22 Exergy efficiency as a function of heat to power ratio

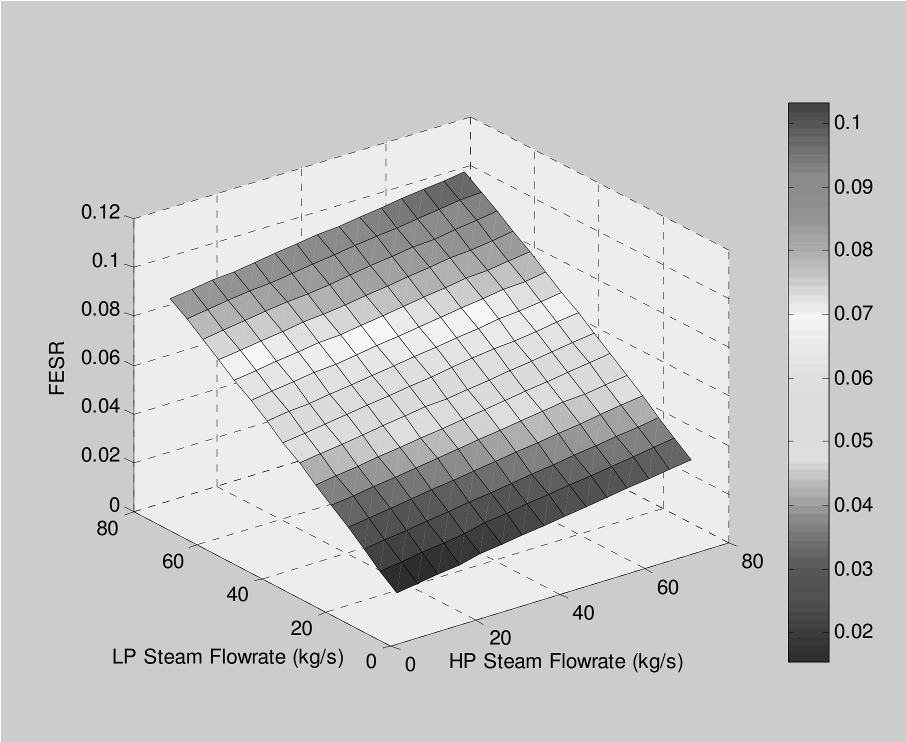

Figure 23 Fuel energy saving ratio as a function of process steam production rates

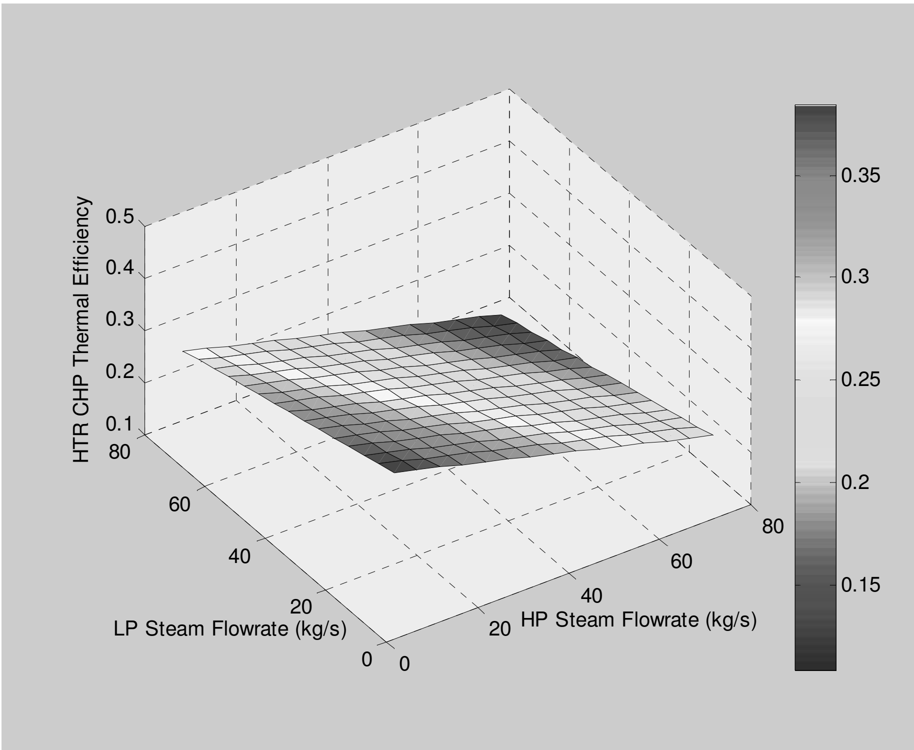

Figure 24 Electrical thermal efficiency as a function of process steam production rates

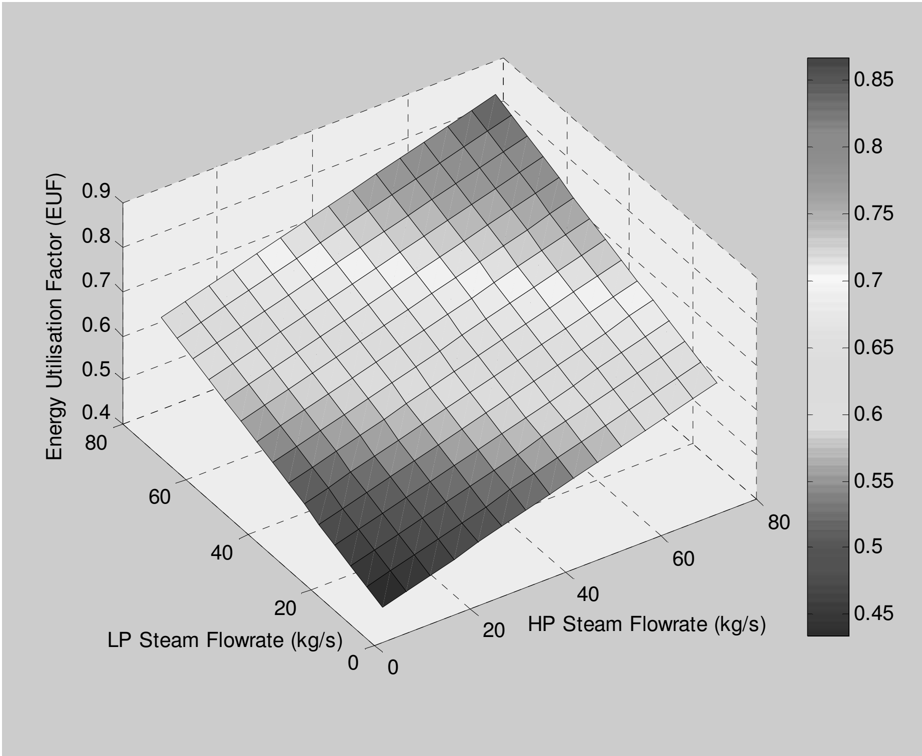

Figure 25 Energy utilization factor as a function of process steam production rates

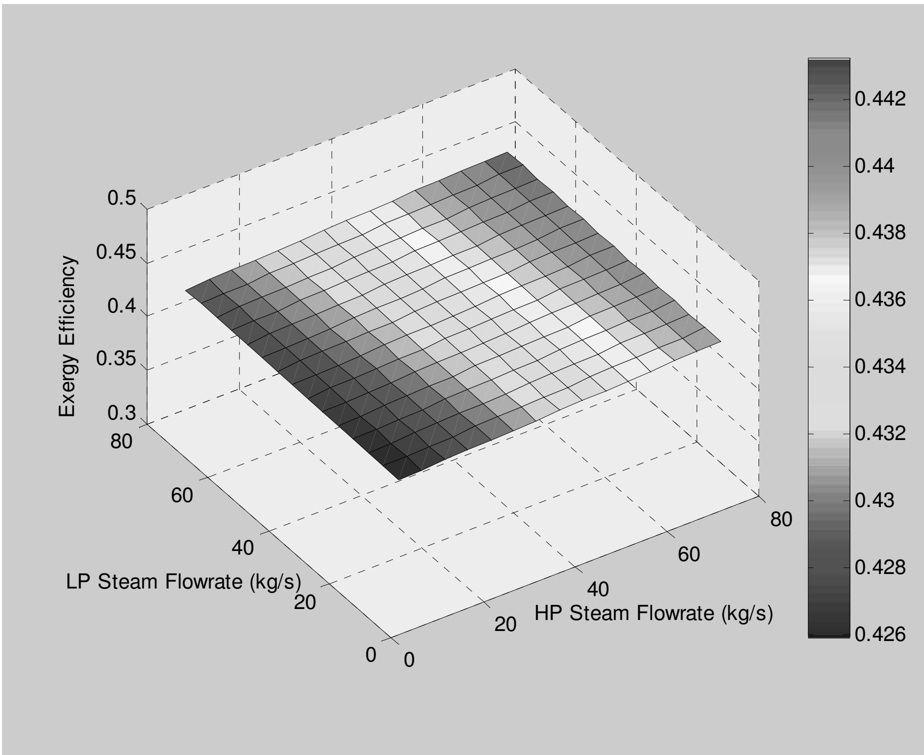

Figure 26 Exergy efficiency as a function of process steam production rates

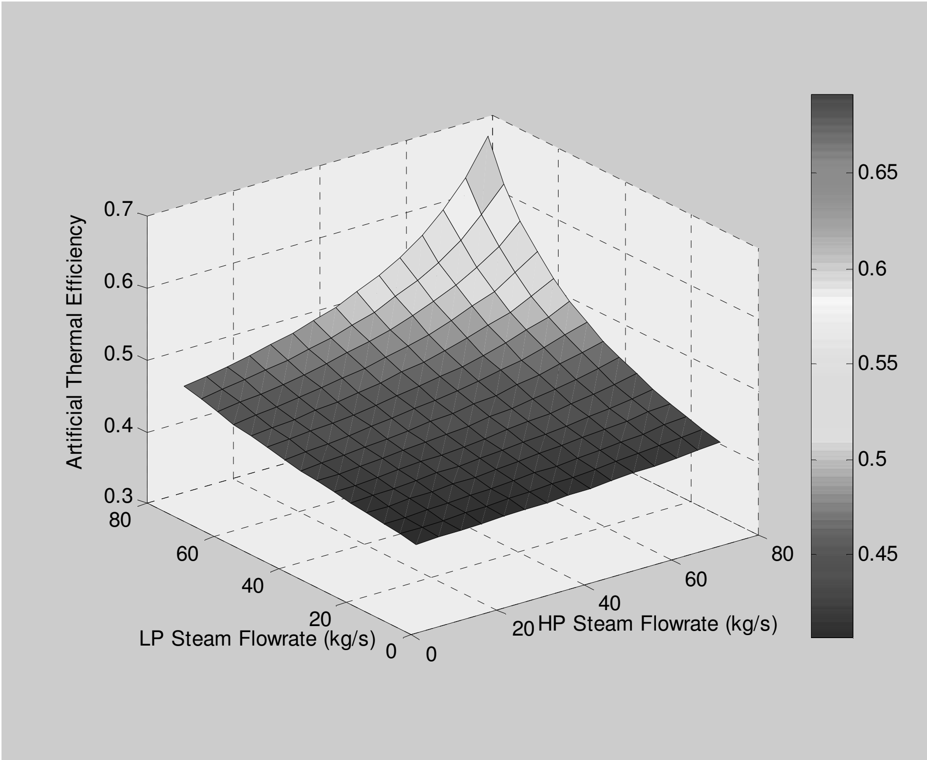

Figure 27 Artificial thermal efficiency as a function of process steam production rates

5.1.6 Off design performance

The off design performance of the cogeneration system was investigated. Zero process steam supply rate both from the HP side and LP side was selected as the design condition. Under this condition all the steam generated in the steam generator flows through turbines and hence represents full load condition for the turbine-generator. Therefore the turbines are designed to swallow this maximum steam flow. Any extraction for process heat supply will represent off design or part load operation for the steam turbine-generator system. The maximum achievable process steam supply rate for the off design operation is about 50 kg/s (both from the HP and LP side) and represent about 2.54 heat to power ratio.

The comparison between the design and off-design operating performances at different heat to power ratios are shown Figure 28, Figure 29, Figure 30, Figure 31 and Figure 32.

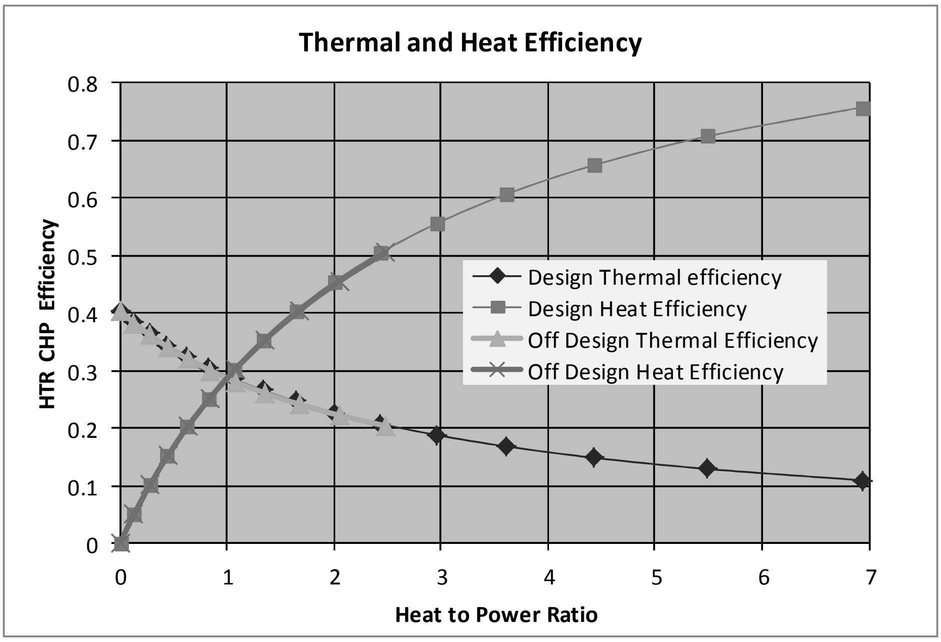

Figure 28 Changes in thermal and heat efficiency

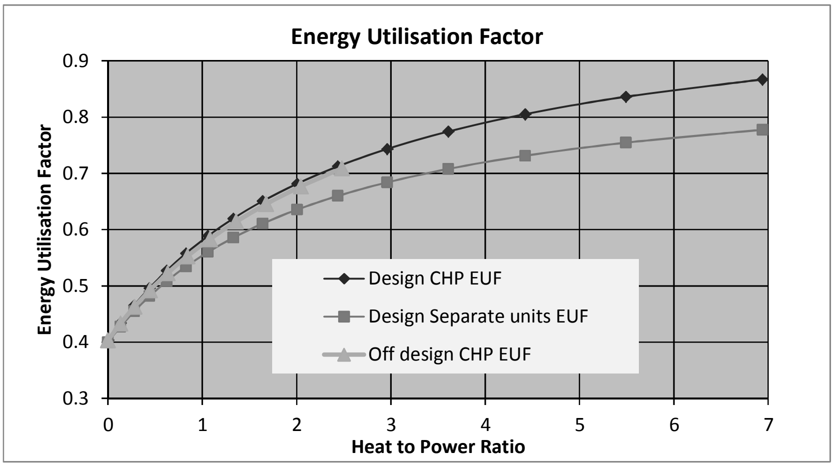

Figure 29 Changes in energy utilization factor

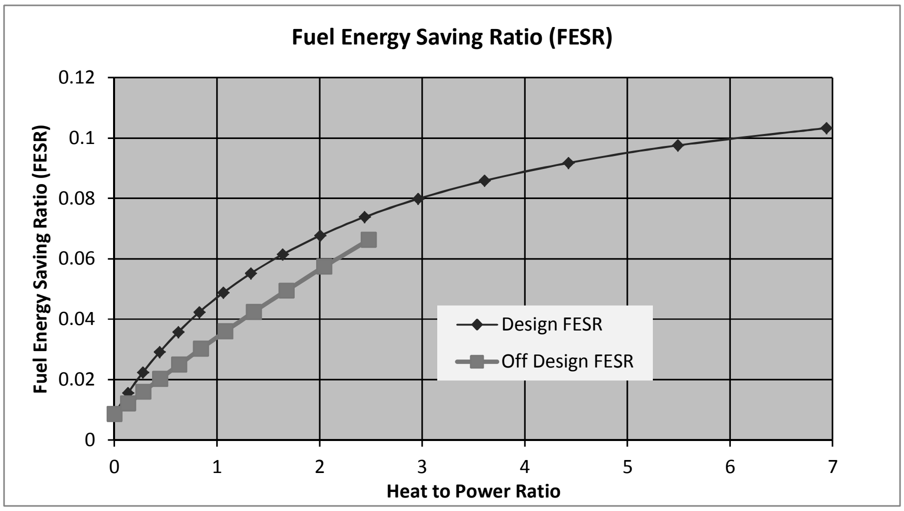

Figure 30 Changes in fuel energy saving ratio

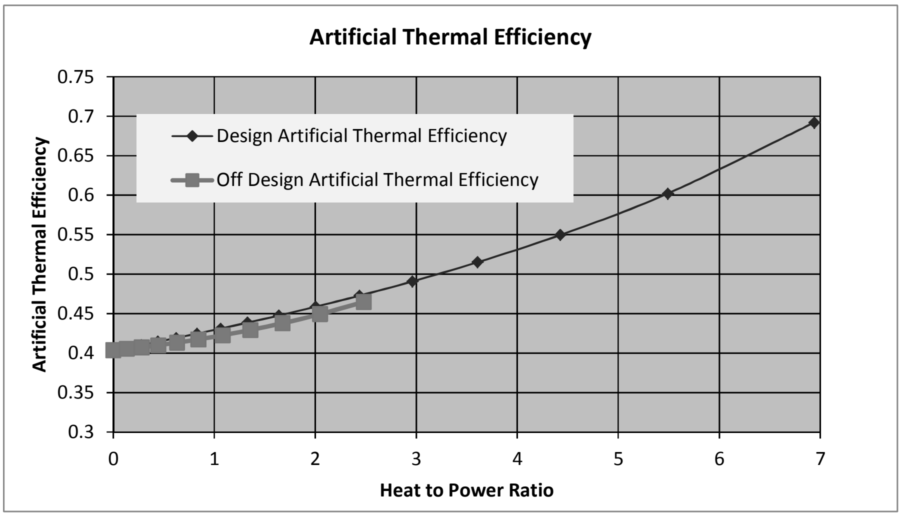

Figure 31 Changes in artificial thermal efficiency

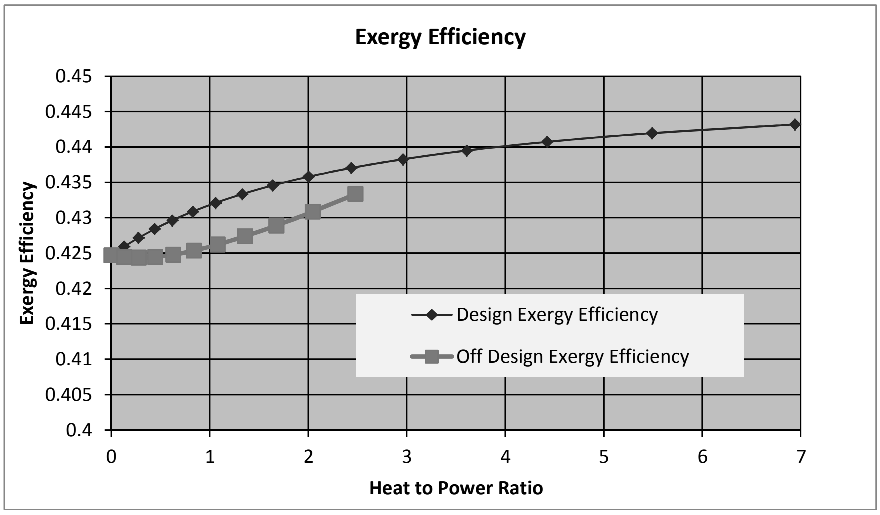

Figure 32 Changes in exergy efficiency

6.0 Conclusions

Assessment of power conversion systems of advanced high temperature reactor for cogeneration of heat and electricity has been carried out in this study. The need for a demonstration plant was enumerated by first reviewing available cogeneration cycle concepts, mainly from the fossil fuel plants in which ALSTOM has extensive experience. The condensing steam turbine concept is a suitable application because it offers a wide range of design flexibility and performance specification. They are designed so that steam for the thermal load is obtained by extraction from one or more intermediate stages at the appropriate pressure and temperature. The remaining steam is exhausted to the pressure of the condenser, which can be as low as 0.045 bar with a corresponding condensing temperature of about 31 ℃. Then the feasibility of a HTR cogeneration secondary system was investigated based on previous research work on high temperature rectors and available technologies. HTR cogeneration plant can support process heat demand requiring process steam at temperature up to 600 ℃ (or 550 ℃ as the case may be) considering existing or near term technology. However there may be need for further studies on steam generator using helium as the hot stream. There seems to be no technical impediments to coupling nuclear reactors to industrial process applications, although safety-related studies of coupled systems may still be necessary. Finally, a conceptual design and cycle performance analysis of a nuclear cogeneration system for industrial application was carried out. The design was based on information gathered from previous HTR cogeneration related programmes and the tasks in this ARCHER Sub-Project. The cycle consists of a steam generator, 2 steam expansion stages (high and low pressure turbines), one condenser, a total of 5 surface feedwater heater, one de-aerator, 2 reboilers (for high and low pressure process steam supply). A 600 MW nuclear reactor with steam generator outlet temperature of 600 ℃ is specified for the conceptual design. The system is designed to deliver process steam at two pressure levels: the high pressure process steam at 550 ℃ (or 500 ℃ if there is intermediate reboiler, the cycle provides the options of intermediate reboilers which help to create tertiary loops between the steam cycle and the industrial process thereby reducing further the possibility of carry-over of radioactive contaminants to the process side.) and low pressure process steam at 300 ℃. Different values of steam supply rate can be selected depending on the desired mix of process heat/electricity production. Study of the system performance criteria shows satisfactory results. The HTR steam cycle has a good level of flexibility. The system can shift energy between electricity generation and heat supply as process steam demands vary, while keeping the reactor power constant.

7.0 Nomenclature

Symbols	Description	Unit
E	Energy input rate	Watts or J/s
EUF	Energy utilisation factor	-
Ex	Total exergy	Watts or J/s
FESR	Fuel energy saving ratio	-
LHV	Lower heating value	J/kg
m	Mass flow rate	kg/s
Q	Thermal power output	Watts or J/s
R	Fuel energy grade function	-
W	Power	Watts or J/s
η	Efficiency	-
λ	Heat to power ratio	-
Φ	Exergetic temperature factor	-
Ψ	Exergetic efficiency	-
Δ	Change	-

Subscripts

a	Artificial
B	Boiler
e	Electrical
f	Fuel
h	Heat
in	Input
m	Prime mover
out	Output
s	Prime mover shaft
u	Useful

Abbreviations

ACACIA	AdvanCed Atomic Cogenerator for Industrial Applications
ANTARES	Areva New Technology based on Advanced gas-cooled Reactor for Energy Supply
ARCHER	**A**dvanced High Temperature **R**eactor for **C**ogeneration of **H**eat and **E**lectricity **R**&D
BEE	Bureau of Energy Efficiency
C2ES	Centre for Climate and Energy Solutions
CHP	Combined Heat and Power
CRES	Centre for Renewable Energy Sources and Saving
DECC	Department of Energy and Climate Change
DS	Deployment Strategy
EDUCOGEN	The European Education Tool on Energy-Efficiency Through the Use of Cogeneration
Euratom	European Atomic Energy Community
EUROPAIRS	End-User Requirements fOr industrial Process heat Applications with Innovative
GT-HTR300C	Gas Turbine High Temperature Reactor 300-Cogeneration
GT-MHR	General Atomics Gas Turbine-Modular Helium Reactor
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HTR	High Temperature Reactors
HTR-TN	High Temperature Reactor Technology Network
HTTR	High Temperature engineering Test Reactor
IAEA	International Atomic Energy Agency
IC	Internal Combustion
IEA	International Energy Agency
INCOGEN	Inherently safe Nuclear COGENeration
LP	Low Pressure
NGNP	Next Generation Nuclear Plant
NHDD	Nuclear Hydrogen Development and Demonstration
NOAK	Nth-Of-A-Kind
OEM	Original Equipment Manufacturer
OSEC	Onsite Sycom Energy Corporation
PBMR	The Pebble Bed Modular Reactor
seai	Sustainable Energy Authority of Ireland
SHP	Separate Heat and Power
SNETP	Sustainable Nuclear Energy Technology Platform
SRA	Strategic Research Agenda
UNEP	United Nations Environmental Programme

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APPENDIX C

PROCHEM CASE STUDY DATA

(SAIPEM CONTRIBUTION)

PROCHEM CASE STUDY DATA

Contribution from SAIPEM SA

1. INTRODUCTION

This case study is based on data provided by Prochem. The material handed over by Prochem contains the description of the main process units integrated in typical Oil Refineries. This information is completed by more general information from other sources in order for the reader not familiar with oil processing to have a better understanding of the subject.

2. GENERALITIES ON OIL REFINERIES

A crude oil is a mixture of many different hydrocarbons. In a refinery, the feedstock is processed in order to:

- Prepare several blends of products, ranging from the light hydrocarbons to the heavier ones. This is mostly achieved via distillation processes.
- The first processing step consists in the distillation steps, which deliver several blends of products.
- These ones are further treated in order to obtain the desired quantities of products with the correct chemical specifications. According to the market demand, the heavy hydrocarbons are converted into lighter more valuable products, by cracking of the long chains, addition of hydrogen to the molecules obtained
- The products are purified to remove impurities like sulphur, nitrogen, metals.

A refinery include a large number of distinct process units. It would be too long to describe all processing steps. In the following, only the oil distillation and hydrotreating units are presented. They represent a large share of the steam consumption of the complex. They are also good examples of the steam utilization techniques in this kind of industry.

Figure 2-1 summarizes the main process steps present in a typical Oil refinery.

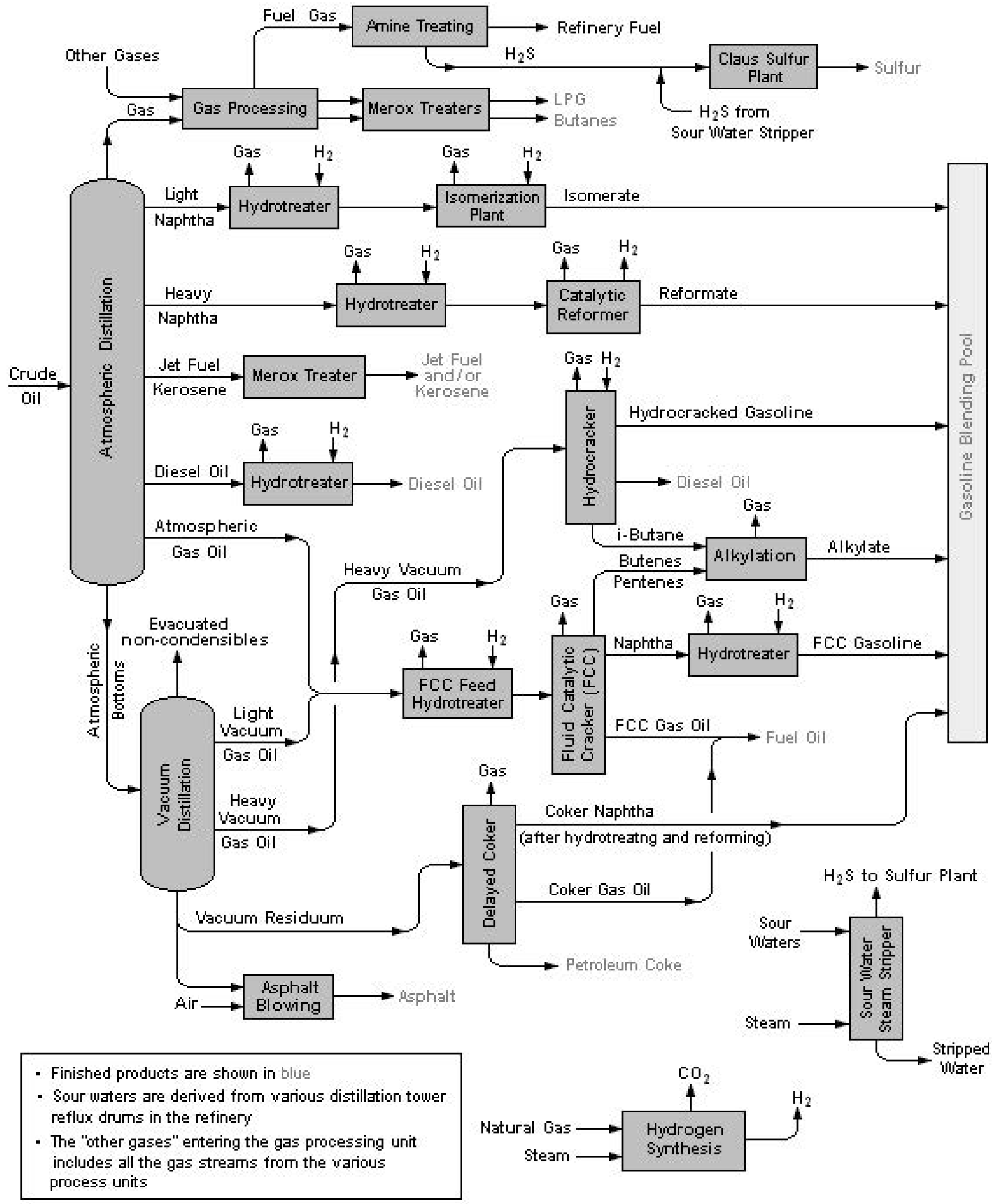


Figure 2-1 : Schematic diagram of an Oil refinery, showing the main process units – Source :http://en.wikipedia.org/wiki/Oil_refinery

3. CRUDE OIL AND PRODUCTS STORAGE

3.1 STORAGE TANKS

The crude is received by pipelines from a distant production zone or from a nearby harbour where tankers are unloaded.

The crude is stored in large tanks. For strategic reasons, the storage capacity may represent several weeks of operation.

The refined products are also stored in dedicated tanks, which are designed according to the volatility and the fluid properties of the product.

Figure 3-1 : Aerial view of crude oil storage tanks

3.2 HEATING OF TANKS AND PIPING

Depending on the type of crude, it may be necessary to maintain a sufficient temperature inside the tanks to keep the product viscosity within the limit required for pumping. The heavy oils resulting from the distillation are also stored in tanks where the same problem exists. Such tanks are heated by internal bundles of tubes fed with steam.

The piping network within the whole plant must also be heat traced where the fluids transported require a minimum temperature.

In cold countries, the corresponding consumption of steam may be very high in wintertime. The Prochem case is a good example.

4. CRUDE OIL DISTILLATION UNITS

4.1 PROCESS DESCRIPTION

The crude oil is a mixture of large number of hydrocarbons, starting from methane up to molecules containing 60 or more carbon atoms. Those hydrocarbons are members of ail homologous series. Crude oils contain also appreciable quantity of organic non-hydrocarbon constituents, mainly sulphur, nitrogen and oxygen containing compounds,
and in smaller amounts, organometallic compounds in solution and inorganic salts in colloidal suspension. These constituents appear throughout the entire boiling range of the crude oil, but concentrate mainly in the heavier fractions and in non-volatile residues. Although their concentration in distillate fractions may be quite small , their influence on final product quality is important.

Mixture of hydrocarbons present in crude oil does not have a single boiling point, but they boil over a range of temperature depending on pressure, composition and nature of process apparatus. Final boiling point of Ural Vacuum Residue defined at 760 mm Hg in accordance with ASTM D 1160 is 816°C. Distillation range is of value in assessing the suitability of crude oil fractions for various applications, particularly in respect of volatility. Such information is also needed for the design and control of distillation columns. The grater the difference in volatility between selected fractions to be separated from crude oil, the easier will be the separation.

Crude Oil Distillation Process is carried out in two stages: first under a pressure slightly above the atmospheric and then in vacuum conditions. The purpose of vacuum is to reduce the temperature level required for the distillation, so that high boiling components of crude oil do not undergo thermal degradation, which would negatively influence quality of resulting distillates. Under deep vacuum and in presence of steam, boiling point of crude oil components is much lower. In those conditions heavy hydrocarbons can vaporise at lower temperature and keep stability. The resulting effect of vacuum is also savings of fuel consumed by furnace, which preheat crude oil atmospheric residue to required vacuum distillation temperature.

Figures 4-1 and 4-2 show simplified diagrams of these units.

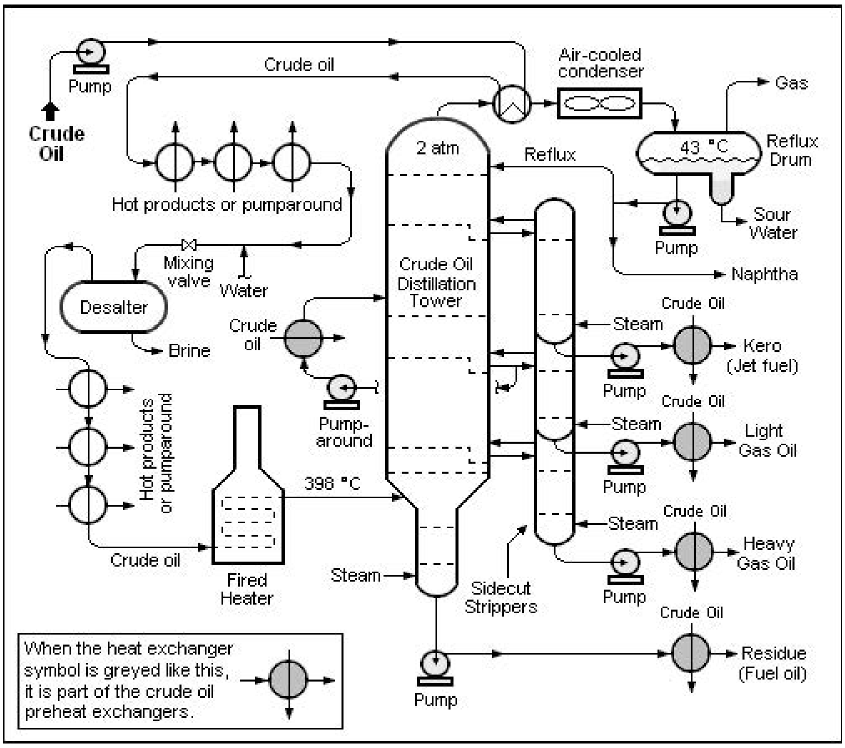


Figure 4-1 : Simplified diagram of the Atmospheric Distillation Unit, showing the use of steam in the distillation column and the side strippers. The residue is further processed in the vacuum distillation unit – Source : http://en.wikipedia.org/wiki/Oil_refinery

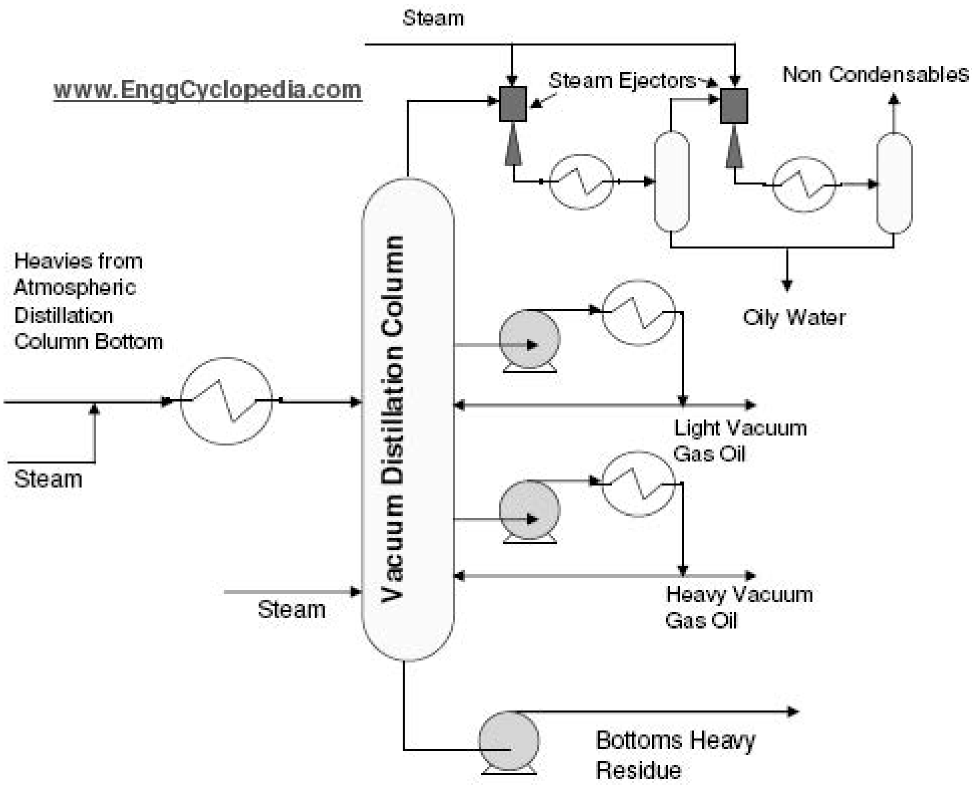


Figure 4-2 : Simplified sketch of a vacuum distillation unit, showing the use of steam – Note the steam ejectors for vacuum control – source : www.enggcyclopedia.com

Simultaneously, thanks to vacuum more valuable hydrocarbons are removed from vacuum residue, increasing yield of oil distillates. Finally, the effectiveness of crude oil processing is improved.

The Simplified Process Flow Diagram of Crude Qil Distillation Unit is included as Figure 4-3. In the following section, the description refers to numbers which are indicated on this drawing.

Crude Oil Distillation Unit employs an Atmospheric and Vacuum Distillation Column with the side strippers and pumparounds to separate crude oil into the required fractions. A large temperature gradient in 100-C01 Atmospheric Distillation Column and deep vacuum in 100-C02 Vacuum Distillation Column enhances this separation. The temperature gradient is achieved using the crude oil heating furnace, pumparounds, and reflux.

The crude oil keeps the bottom of distillation column hot and pumparounds remove heat at various trays in both columns. In a pumparound, liquid is removed from a tray and is cooled by cross exchange with cold streams. It then re-enters the column's superior tray. The columns overhead stream is condensed and a portion is fed back to the top tray as reflux. This cools the top of the columns.

The side strippers are used to strip the light components from fractions. They re-enter the distillation columns as a vapours. The liquid fractions then flow from the bottom of the strippers, are heat exchanged and cooled down. Low Pressure Steam previously superheated in the coils inserted in furnaces convection section is used as stripping medium, both in distillation columns and stripers.

Crude oil from storage tanks or from surge drum is pumped by the charge pump through a series of crude / distillates heat exchangers in order to increase the crude stream to the required OD-01 desalter inlet temperature. The purpose of the desalter is to remove dissolved salts from the crude oil which would otherwise cause troublesome solids deposits. Water, in the range of 3 to 7 % of crude rate is introduced into the line, upstream of the mixing valve. The water / oil mixture enters the desalter where the water, dissolved salts (principally sodium chloride) and other compounds are separated from the crude, settled and drained to safe disposal. Desalted crude flows from the top of the desalter on pressure control through pumparound and distillates exchangers to further preheat the crude and reduce the heat requirement of the 100-F01 crude furnace.

Crude oil leaving the exchanger system is heated up to approx. 210°C thanks to heat exchange against top fraction from Atmospheric Distillation Column and all side fractions from the strippers. The crude oil is further heated in 100-F01 furnace, where it would be partly vaporized before entering the flash zone at the botlom of the Atmospheric Distillation Column. The furnace transfer line temperature is controlled by resetting the flow of the fuel to furnace burners. Process off-gas is usually used as a main fuel. It can be associated by heavy fuel oil, which is preheated and atomised by medium pressure steam. Natural gas is also connected to the fuelling system of furnace, but can be used only at furnace start-up or in case of main fuel failure.

Crude oil heated to approx. 330°C enters the 100-C01 Atmospheric Distillation Column flash zone. The lightest components of the crude oil evaporate in flash zone and flow up the superior trays, while the heaviest components fall to the bottom of the column. The lighter components from Atmospheric Distillation Column botlom are stripped by a controlled flow rate of Superheated Low Pressure Steam and are going up with the vapour phase the from flash zone. Three different fractions are then separated according to the respective boiling points, via condensation on the different trays within the column. Each side fraction flows to the stripping column, where Superheated Low Pressure Steam is added for removal of the lightest hydrocarbons in order to improve some properties, first of all the flash point.

Light gaseous components and overhead vapours leave the top of the Atmospheric Distillation Column, preheated crude oil in E-1 exchanger and are condensed in the E -2 atmospheric vapour condenser. The mixture then flows to the OR-1 reflux accumulator, where light hydrocarbons are separated from naphtha. Light hydrocarbons exit the top of the accumulator via the distillation column pressure controller and flow to the separation Unit. LPG is recovered in that Unit, while dry gases are connected to off-gases network.

Ammonia and inhibitor are pumped into the overhead system to reduce corrosion and maintain the pH of the overhead liquid. Stripping steam condensate is pressured from the boot of OR-1 reflux drum and is removed through interface level control as sour water, or sent back to the desalter water drum.

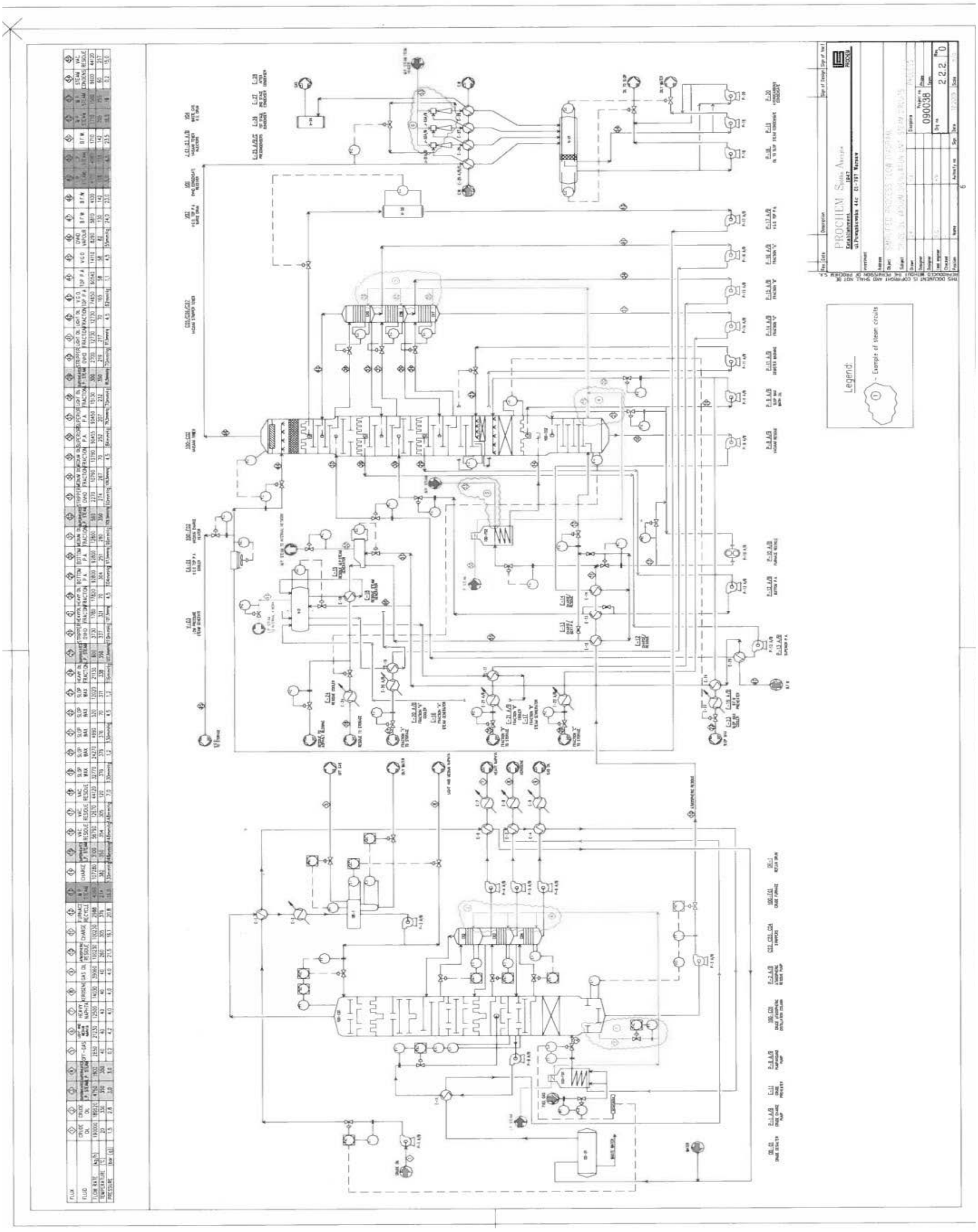


Figure 4-3 : Process Flow Diagram of the Distillation Units

In course of winter season the boot of accumulator is heated by an external coil supplied with Low Pressure Steam. The cold light and medium naphtha is sent partially to the top tray of the Atmospheric Distillation Column as reflux and remaining quantity is stored in tanks before further processing.

The hot fractions of heavy naphtha, kerosene and gas oil are withdrawn from the relevant trays of the Atmospheric Distillation Column and sent to the C02/C03/C04 strippers. They are stripped of light ends with Superheated Low Pressure Steam. The light ends vapours and steam are coming back to the superior trays of the Atmospheric Distillation Column, while liquid phase from the strippers is pumped out through heat exchangers and water coolers to storage tanks. The resulting atmospheric residue is pumped from the Atmospheric Distillation Column bottom through the flow control valve governing the level control and flows either directly to the Vacuum Distillation Column charge furnace or is cooled in a heat exchanged before being sent to storage.

The crude atmospheric residue is heated up in 1 00-F02 furnace to approx. 390°C. Dewatered Medium Pressure Steam is injected in quantity of approx. 4 tons per hour to the residue passing the tubes section between convection and radiation section of furnace. This steam makes vaporisation of the residue easier at lower temperature. Residue vaporises partially and passes to the 100-C02 Vacuum Distillation Column operated at vacuum of 50/148 mm Hg.

The vacuum in this column is created by the steam ejectors J-01A1B + J-03A1B system, composed of three-stage ejectors, which remove steam and gases from the top of the Vacuum Distillation Column. Overhead vapours, mainly steam, are suck-in from the top of the 100-C02 Vacuum Distillation Column, condense in overhead condensers and flow to the V-01 condensate accumulator. The vacuum control valve is installed on the non-condensable line from the E-28 after the condenser, which keeps a stable vacuum in the 100-C02 Distillation Column.

Gases from V-01 are separated in V-04 drum and then are burnt in a separate burner installed in the 100-F02 furnace. Steam ejectors are supplied with Medium Pressure Steam. The steam pressure shall be stable to avoid fluctuations of vacuum created and finally, disturbances in the operation of the Vacuum Distillation Column.
The condensate is then pumped from V-01 through level control valve to the waste water treatment Unit or to the crude oil desalter. The overhead liquid fraction of VGO is drawn from the chimney tray at 180°C and flows to V-02 surge drum. Here, gases are disengaged and return to the column superior tray. VGO is pumped from the drum through the EA-01 air cooler, where its temperature is reduced down to 54°C. The majority of VGO then returns through the flow control valve to the Vacuum Distillation Column as reflux. The rest flows to storage by flow control.

Three side distillates are withdrawn from the Vacuum Distillation Column: light, meddle and heavy oil fraction. Light oil fraction is drawn from tray and flows to C05 vacuum stripper. The light components are removed by Superheated Low Pressure Steam and return to a tray above in the Vacuum Distillation Column. The liquid phase is pumped out from the bottom stripper through E-16 heat exchanger integrated with V-03 Low Pressure Steam Generator and then through water cooler to storage. Meddle oil fraction is drawn from relevant tray and flows by stripper liquid level control to C06 vacuum stripper. Superheated Low Pressure Steam is injected and the steam and lighter components exit the top of the stripper and re-enter the top tray in 100-C02 Vacuum Distillation Column. Meddle oil fraction is pumped out through E-17 heat exchanger integrated with V-03 Low Pressure Steam Generator and then through water cooler to storage, by flow control. Heavy oil fraction is drawn from relevant tray and flows by stripper liquid level control to C07 vacuum stripper. Superheated Low Pressure Steam is injected and the steam and lighter components exit the top of the stripper and re-enter on tray above in 100-C02 Vacuum Distillation Column. Heavy oil fraction is pumped out through E-22 AIB water cooler to storage, by flow control.

Vacuum residue at temperature of 354°C is withdrawn from the bottom of 100-C02 Vacuum Distillation Column by level control and passes through E-12 and E-14 heat exchangers, and then enters the E-15 Medium Pressure Steam Generator. Its temperature is 240°C at generator inlet and 206°C at generator outlet. Vacuum residue at that temperature next passes through E-18 heat exchanger integrated with V-03 Low Pressure Steam Generator.

The V-03 Low Pressure Steam Generator produces saturated steam at a pressure of 5 bar(g) and a temperature of 158°C. A part of the vacuum residue from the exchanger outlet is sent to Bitumen Blowing Unit and the remaining quantity flows through tubes of E-24 cooler, where tempered water is used as a cooling agent. Finally, the vacuum residue at a temperature of 136°C is sent to the storage. The E-15 Medium Pressure Steam Generator produces saturated steam at a pressure of 16,5 bar(g) and a temperature of 205°C.

4.2 FEEDSTOCK

Crude Oil Distillation Unit processes Russian Export Blend Crude Oil (REBCO) or similar heavy and high sulphur crude as Arabian Light. There is also possibility of processing light low sulphur crude oil in blend mixture with REBCO at a share up to 20 %, unless it is shown to be uneconomic.

4.3 PRODUCTS SPECIFICATION

Products specification meets the requirements of EU directives concerning petrol, diesel and gas-oil for transportation purposes, fuel oils used by large sources producing energy and domestic fuel oil. The bitumen, lube oils and speciality products addressed to internal market are in accordance to current regulations. The process Units are technically adjusted to new clean fuels regulatory requirements with either minor modifications or relatively low cost capital investment.

4.4 UNIT CAPACITY

Crude Oil Distillation Unit nominal capacity is evaluated at 1,5 million tons of REBCO per year, assuming that annual continuous operating time will be minimum 8000 hours.

4.5 HAZARDS OCCURING DURING UNIT OPERATION

Emergencies and associated hazard can be caused by equipment ruptures, serious leaks, fires and potential/total failure of utilities inclusive steam. Each emergency situation, such as loss of utility, mechanical failure, or a leak, will require difference level of response. Fire is a serious hazard in Crude Oil Distillation Unit, due to presence of light hydrocarbon liquids and gasses. They present also a potential for explosion. Fire prevention system include gas and fire detectors for hazardous area, smoke and/or heat detectors for non-hazardous areas and manual devices initiating alarm. Fire pump operation and loss of fire water header pressure initiate tire alarm. Ali hazardous located tire detectors operate the site horn and ESD the affected section of the Unit. In case of fire operations personnel should follow General Emergency Shutdown Procedure.
In general, the normal safety rules pertaining to the handling of hydrocarbons under pressure and high temperature also apply to the Crude Oil Distillation Unit. Following an emergency shutdown additional steps are required to further shutdown the Unit in preparation for Unit maintenance or start-up. Some emergencies can be tolerated for a short time period of time without a complete shutdown if the proper measure is taken. The type and severity of the emergency will determine the steps that should be taken. The operator should attempt to maintain normal operation if there is no danger to personnel or equipment. However, if more extreme steps must be taken, the Unit must first be put into a

safe condition. If the event of an emergency shutdown, feed to the Unit shall be stopped immediately.
Operating risks are quite high during the shutdown stage, mainly due to the large temperature excursions, which may result in mechanical troubles, such as losses due to gasket failure or accidental ruptures.

The unit is fitted with the suitable pressurizing, depressurizing, draw-off and venting provisions for individual equipment and process section. Blow down systems, drainage and equipment protecting against excessive pressure and temperature rise inside the Battery Limit are in accordance with API regulations.

4.6 STEAM CONDITIONS

Steam is supplied to Battery Limit of Crude Oil Distillation Unit by steam producer and supplier, i.e. the Power and Steam Station. Crude Oil Distillation Unit uses steam at two different levels of pressure:

1- Medium Pressure Steam, MP
2- Low Pressure Steam, LP

Table 4-1 : Conditions of steam at Battery Limit of the Distillation Units

Steam description	Operating pressure, MPa (g)			Operating temperature, °C		
	Min.	Norm.	Max.	Min.	Norm.	Max.
Medium Pressure Steam, MP	1.80	1.90	2.20	220	250	275
Low Pressure Steam, LP	0.35	0.45	0.60	170	200	240

Each kind of steam is supplied from Power and Steam Station to Unit's Battery Limit, where cut-of valves, instrument devices and totalizing flow meters are installed. Steam producer is responsible for continuous supply of steam through main pipelines and stable conditions of steam. Steam flow rate, temperature and pressure on inlet to Battery Limit are monitored on DCS panel. If required conditions of steam are not met, the proper alarm is coming to DCS and panel operator of the Unit shall undertake an action in order to avoid process disturbances.

Low Pressure Steam at conditions specified in above table is used mainly for the second importance operations, Le. for process lines steam tracing and for heating the medium by coils installed inside or outside process equipment and intermediate reservoirs. Before usage in distillation process that steam is superheated first in the coils installed in convection section of both furnaces by heat exchange with flue gases leaving that section. Steam temperature on superheater outlet is controlled at 350 °C by temperature controller, which gives a signal to steam flow control valve placed on the line venting the steam to atmosphere. The quantity of venting steam is correlated with total consumption of superheated steam respectively in atmospheric and vacuum part of the Unit. If sooth is present in flue gases as a consequence of improper fuel combustion in furnace, there would be difficult to rich steam required temperature. In such a case superheater shall be blown with jets of steam, released through nozzles of movable special device. Superheated steam at temperature of 350 oC is not used as heating medium, butexclusively as stripping agent to both distillation columns and strippers. Superheatedsteam loops connected to that equipment are shown on drawing No 2.2.2. The quantity of steam consumed in specified loop is included in balance table on the drawing and in item 2.2.10 of present Document.

4.7 STEAM FUNCTIONS IN THE PROCESS

Steam has the following functions in Crude Oil Distillation Process:

1- Stripping medium to strippers of atmospheric and vacuum side fractions;
2- Stripping medium to atmospheric and vacuum distillation columns;
3- Medium pulling a vacuum by means of ejectors system;
4- Atomisation of heavy fuel oil on burner's outlet into furnace combustion zone;
5- Medium for periodical blowing of furnaces convection section, inclusive superheater of Low Pressure Steam. During that operation Crude Oil Distillation Unit can remain on stream;
6- Medium for steam tracing of process lines and intermediate vessels handling heavy fractions and residues. That operation shall be carried out during winter season and in course of remaining months also, if HVGO and vacuum residues are produced;
7- Medium for equipment purging before plant turnaround maintenance or individual equipment repair;
8- Extinguisher of fire and air removal agent from radiation section of furnace in case of tube rupture. It is a snuffing steam manually operated by operators if needed;

The first four functions of steam are essential for Unit smooth operation and process performances. Steam supply to above mentioned consumers shall be continuous and steam conditions shall be stabile as per process requirements. Fluctuations of steam pressure and temperature can lead to improper control of operating conditions and finally will cause Unit shutdown.
The last four functions of steam are not linked directly to Crude Oil Distillation Process. Low pressure steam for those operations is needed periodically, at variable quantity and time.

4.8 STEAM CIRCUITS AND CONSUMPTION

Consumption of steam in Crude Oil Distillation Unit is calculated separately for each circuit specified on the Process Flow drawing. Data concerning to steam consumption are included in the table 2.

Table 4-2 : Steam circuits and consumptions in the Distillation units

<table>
<tr><th rowspan="2">Steam Circuit N°</th><th rowspan="2">Steam consumer/receiver</th><th colspan="3">Steam flowrate kg/h</th><th rowspan="2">Steam function</th><th rowspan="2">Remarks</th></tr>
<tr><th>Low Pressure Steam, LP</th><th>Superheated Low Pressure Steam, SLP</th><th>Medium Pressure Steam, MP</th></tr>
<tr><td>1</td><td>100-C01 Atmospheric Distillation Column bottom</td><td rowspan="2">6700
+ 15% *</td><td>4750</td><td>-</td><td>Stripping medium</td><td>LP steam superheated in 100-F01 Furnace</td></tr>
<tr><td>2</td><td>C02, C03, C04 Stripping Column bottom</td><td>1950</td><td>-</td><td>Stripping medium</td><td>Separate inlet of SLP steam to each Stripping Column</td></tr>
<tr><td>3</td><td>100-F02 Furnace heating coil</td><td>-</td><td>-</td><td>4060</td><td>Preventive, against coke formation</td><td>Steam for turbulence flow. It remains in feed to 100-C01 Atmospheric Distillation Column</td></tr>
<tr><td>4</td><td>100-C02 Vacuum Distillation bottom</td><td rowspan="4">4100
+ 15% *</td><td>3100</td><td>-</td><td>Stripping medium</td><td rowspan="4">LP steam superheated in 100-F02 Furnace</td></tr>
<tr><td rowspan="3">5</td><td>C05 Stripping Column bottom</td><td>300</td><td>-</td><td>Stripping medium</td></tr>
<tr><td>C06 Stripping Column bottom</td><td>350</td><td>-</td><td>Stripping medium</td></tr>
<tr><td>C07 Stripping Column bottom</td><td>350</td><td>-</td><td>Stripping medium</td></tr>
<tr><td>6</td><td>Ejector System
J-01 A/B – J-03 A/B</td><td>-</td><td>-</td><td>1500</td><td>Vacuum pulling</td><td>Dewatered MP Steam</td></tr>
<tr><td colspan="2">Total</td><td>12420</td><td>10800 **</td><td>5560</td><td colspan="2"></td></tr>
</table>

*15 % excess of steam for compensation of steam lost to atmosphere while SLP steam temperature control is on line** represents equivalent quantity of LP steam before being superheated

Neither Superheated Low Pressure Steam nor Medium Pressure Steam injected into 100-F02 furnace and passing through Ejectors System is consumed physically, although it has a direct contact with process media. Almost all quantity of that steam is recovered as a condensate phase separated out of liquid overheads from Atmospheric Distillation Column and is collected in condensate receiver from Vacuum System. Steam condensate contains small quantity of dissolved hydrocarbons which makes necessary condensate treatment before reuse.
Additional quantity of Low Pressure Steam is needed for periodically carried out operations, which are not linked directly to Crude Oil Distillation Process, i.e.:

1- Steam tracing of process lines and intermediate vessels handling heavy fractions and residues. That operation shall be carried out during winter season and in course of remaining months also, if HVGO and vacuum residues are produced;
2- Periodically blowing of fumaces convection section, inclusive superheater of Low Pressure Steam;
3- Equipment and process lines purging before Unit tumaround maintenance or individual equipment repair;
4- Coke removal from furnaces coil by controlled combustion, in case of significant pressure drop and during Unit turnaround maintenance;

Consumption of Low Pressure Steam for first item can be evaluated at 0,8 t/h during summer and 1,5 t/h in winter time. Periodically blowing of furnaces convection section is short time operation and steam consumption is also low. Consumption of steam in operation of coke removal from furnaces coil my vary from 0,85 to even 11 t/h. That operation takes 3 days or more.

4.9 LOCAL STEAM GENERATORS

Fractions of crude oil leave the distillation and stripping columns at high temperature. Temperature of fractions increases with their boiling point. The stream of vacuum residue has the highest temperature of 350°C or more. Heat recovery from distillates and vacuum residue is accomplished in a series of heat exchangers, for crude oil preheating first and second to steam generation. Two steam generators are installed in Crude Oil Distillation Unit, which are market with symbol V-03 and E-15 on drawing No 2.2.2.
Generator V-03 has no internal heating coil and it is a steam drum rather. Three streams of softened water circulate from generator bottom under internal pressure through heat exchangers and come back to generator, where steam separates out of water.
Generator produces 4.1 tons per hour of saturated Low Pressure Steam at pressure of 5 bar(g) and temperature 158°C, which is connected to internal network of Low Pressure Steam. Steam pressure is controlled by pressure controller and flow control valve installed on steam outlet.
Generator E-15 has a standard construction with internal tube bundle. Vacuum residue earlier cooled down to 257°C circulates through the bundle and transfers the energy to the softened water. Generated saturated Medium Pressure Steam is sent out by pressure control valve. Generator produces 1.7 tons per hour of saturated steam at temperature of 205°C and pressure 16,5 bar(g). The amount of steam generated is controlled by the pressure controller on steam outlet from generator. The steam generator water feed flow control loop or the water purge flow control loop is cascade controlled by the steam generator level control loop. Both steams are connected to Unit main headers and then as a mixture with steam delivered by Power and Steam Station are used totally in Crude Oil Distillation Unit. Generated Low Pressure Steam can cover more than 30 % of demand for that steam by the whole Unit, while quantity of Medium Pressure Steam is enough to satisfy less when 30 % of steam demand.

4.10 STEAM FAILURE

Steam failure will have consequences to the whole process of crude oil distillation and it will affect particularly:

1- Ejectors System.Steam failure will cause a lost of vacuum in 100-C02 DistillationColumn, followed by disturbances in operating of that column and integrated C04, C05,C06 Stripping Columns. The level in 100-C02 will increase excessively, while in C04,C05, C06 will decrease below set limit. In first step, there will be necessary to changemode of process control from auto to manual one and after short time to stop flow offeedstock to the Unit, and restart hot circulation loop;
2- Vacuum furnace. Lack of turbulence steam will cause substantial decrease in velocityflow through the coil, followed by danger of coke formation inside the coil and materialoverheating on coil section placed in radiation zone;
3- Vacuum Distillation Column. Common effect of lack of vacuum and stripping steam leads to break in distillation;
4- Atmospheric Distillation Column. Lack of stripping steam leads to disturbances in column hydraulics and to brake in distillation;
5- Steam superheaters. If failure of steam occurs, the material of superheater coil will be exposed to thermal tensions and finally to damage;

The main target during steam failure shall focus on protection of furnaces coil against coke formation and rupture, which can initiate a fire. High quantity of heat accumulated by equipment and process media creates danger of self-ignition if flow of media is limited. To avoid ignition, care shall be taken to keep hot media out of leak, contact with air and hot external surfaces. Steam failure usually leads to an emergency shutdown of the Unit. The Unit has to be shut down following the procedure for General Emergency Shutdown.

5. CRUDE OIL DISTILLATES HYDROTREATMENT UNIT

5.1 HYDROTREATMENT PROCESS DESCRIPTION

Crude oil distillates contain undesirable compounds of sulphur, nitrogen, oxygen, unsaturated hydrocarbons and aromatics. All of them exert negative impact on distillates properties and have to be removed or transferred into new hydrocarbons, before distillates become valuable products. Hydroprocessing of oil distillates and residues is the most efficient process to get commercial products at high quality. Hydroprocessing consists in distillate contact with selective catalysts, in presence of hydrogen and at high temperature and pressure, as illustrated on Figure 5-1. As a consequence, the following processes take place:

1- Removal of nitrogen from organic compounds (hydrodenitrification);
2- Organic sulphur removal (hydrodesulphurisation);
3- Removal of oxygen bond into organic compounds (deoxygenating);
4- Hydrogenation of aromatics and unsaturated compounds

The performances of the above processes require a complete methodology to optimise the choices of catalysts, operating conditions, and process schemes. The distillation curve, particularly the distillation end point of the feedstock, has a pronounced impact on operating conditions of deep hydrotreaters.

Deep hydrodesulphurisation processes of middle and heavy distillates enable not only manufacturing of extra low sulphur products but also attainment of some related product characteristics, such as oxidation stability and colour through the whole life cycle. Concerning the products stabilization, the typical operating conditions imposed by hydrodesulphurisation cannot bring about enough hydrodenitrification to stabilize the product, thus the operating conditions (hydrogen partial pressure, liquid hourly space velocity) must be increased in severity. Higher operating hydrogen partial pressure leads to aromatics deepest hydrogenation.

As the severity of hydrotreating is increased and if the product specification is not attained, the best option to adopt is a two-stage process with optimised operating conditions allowing a strong improvement of product quality. However, that solution is costly in respect of investment expenditure and operation. Above mentioned remarks find application in Wax Hydrotreating Process, the subject of next items of present Document.

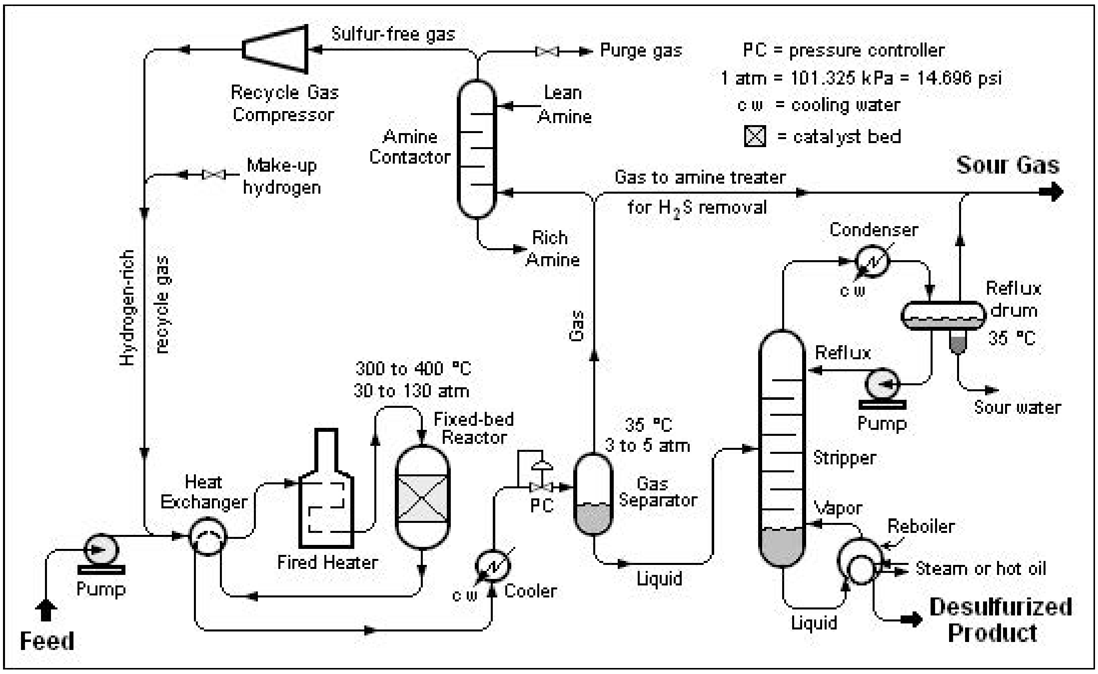


Figure 5-1 : Simplified diagram of hydrodesulphurization – Source : http://en.wikipedia.org/wiki/Oil_refinery

Oil Distillates Hydrotreating Process respects the fundamentals of hydroprocessing. The catalysts and process are aimed at achieving all the stringent final products quality requirements as very low sulphur, nitrogen, oxygen content, low aromatics content, and reduction of heavy ends and improvement of cold flow properties. Hydrotreating of middle distillates generally contained in the 180 to 370°C boiling range and have roughly C16 to C25 carbon numbers, involves mainly removal of sulphur and nitrogen.

Sulphur compounds in this boiling range are mercaptans, sulphides, disulphides, thiophenes, and benzothiophenes. The aliphatic sulphur compounds are the easiest to convert, and the alkyl-substituted dibenzothiophenes are the most difficult. At deep desulphurization levels, the dibenzothiophenes are typically the only remaining sulphur components. When removing the sulphur and nitrogen, the catalyst can also saturate the associated double bonds and therefore increase the hydrogen content, which has a positive impact on many product properties.

The primary aromatics saturation is the hydrogenation of multi-ring and single-ring aromatics to their saturated counterparts. Single-ring aromatics are significantly more difficult to saturate. Aromatics saturation is an exothermic, reversible reaction. The higher the reactor temperature, the lower is equilibrium constant. Therefore, under fixed conditions of pressure and space velocity, the amount of aromatics that can be saturated is limited.

The key operating conditions in distillates hydrotreating Units include hydrogen partial pressure (PPH2), operating temperature or weighted average bed temperature (WAST) and liquid hourly space velocity (LHSV). The value of PPH2 is chosen in function of feedstock composition, distillation range and objectives to be obtained by hydrotreating. In general, hydrogen partial pressure shall be higher, if the feedstock becomes heavier.

The hydrogen partial pressure can range from 20 bar to a light straight run gas oil to 70 bar for heavy distillates or low value by-products coming from thermal and catalytic process, as light circulating oil (LCD). The higher value of PPH2 is favourable for limitation of coke formation during feedstock preheating in furnace Gail. On the other hand the higher value of PPH2 needs operating pressure also higher, what increases investment expenditure and operational costs.

The operating temperature of a hydrotreater should be at an optimum to meet processing objective throughout the run cycle. The only limitation is the maximum operating temperature at which the product colour would fail to meet the specification. Typically, a WAST of 330°C at start-of-run (SOR) and 360°C at end-of-run (EOR) conditions results in an estimated 3-year cycle length with maximum colour of the product. If this target cannot be attained, the hydrogen partial pressure which is favourable for colour improvement should be increased.

Value of liquid hourly space velocity (LHSV) is setting-up residence time of feedstock on catalyst under operating conditions. At low LHSV, residence time increases and hydrotreating performances expressed as grade of desulphurisation, denitrification and hydrogenation are better. However, too long a residence time leads to faster deactivation of the catalyst and is economically disadvantageous. Process constrains and/or economics dictate the optimal selection of the operating variables.

5.2 EXAMPLE OF HYDROPROCESSING : WAX HYDROTREATING PROCESS UNIT

There are several configurations of hydroprocessing system, following the type of purification involved.
Here as an illustration, Oil Distillates Hydrotreatment Process is presented more in details through the example of a Wax Hydrotreating Process Unit.
The target of this process is a significant improvement of the wax purity, colour, temperature stability, reduction of light components, sulphur compounds and aromatics, etc. The process removes sulphur and nitrogen compounds, and it partially saturates cyclic compounds, while undesirable side reactions such as melting point or oil content changes are avoided. Colour and purity improvements are achieved in packed-bed reactors utilizing a Co-Mo catalyst and operation in a two-temperature, two-stage mode. This operation removes sulphur and nitrogen and also provides the required amount of aromatics saturation to meet wax requirements of EU Pharmacopoeia and FDA standards.

A Simplified Process Flow Diagram is shown on Figure 5-2. The units numbers are indicated on this Figure.

The Wax Hydrotreating Unit includes the following sections:

1- Feedstock preheating and filtration;
2- Compression of recycled and make-up hydrogen;
3- Heating up the mixture of feedstock and injected hydrogen to hydrotreatingtemperature;
4- Feedstock hydrotreating in two stage reactors;
5- Reactors effluent heat recovery and separation;
6- Refined wax stripping and drying under vacuum;
7- Injection of antioxidant to stream of wax;
8- Wax product storage;
9- Wild naphtha separation;
10- Recycling of process gases to furnace burner;
11- Flushing oil heating and recycling;

Feedstock from surge drum is partially preheated by exchange with E-02 vacuum drier wax product, before going through F-01 A/B cartridge type filters. This heating step recovers heat from the product and reduces the viscosity of the wax feed downstream feed filter. The feed filters removes particulates that may be in the feed down to 1 micron, which would otherwise plug or deactivate the catalyst. The filtered feed then goes to 0-01 feed surge drum from where it is pumped at the required operating pressure and sent to further preheating obtained by exchange with the second reactor effluent in E-05 and then in the E-04 reactors intercooler.

The feed is combined with the hydrogen and the mixture is sent to H-01 furnace for heating to reactor inlet temperature. The hydrogen is a combination of make-up fresh hydrogen at purity of 99,5 % from storage and recycled hydrogen from 0-03 cold separator.

The total reactor volume is divided into two vessels. The first stage reactor R-01A is working at a higher temperature and accomplishes sulphur and nitrogen removal while the second reactor R-01 B operates at lower temperature, performing the final aromatics saturation needed to ensure food grade quality product. The operating pressure of the reactors is set by the requirement to have a proper hydrogen partial pressure and finally, the required wax product specifications. Reactor effluent is cooled by heat exchange with feedstock and enters the 0-02 hot separator drum, where it flushes. The overhead vapour from this drum is cooled with tempered water in E-06 overhead condenser. This mixed phase stream enters the 0-03 cold separator drum, where the lighthydrocarbon vapours, non-reacted hydrogen and free hydrogen sulphide are separatedfrom the wax liquid.

The overhead vapour from 0-03 is the high pressure tail gas, rich in hydrogen. The majority of the high pressure tail gas is compressed as recycle gas in C-02A1B compressor, combined with the make-up fresh hydrogen from storage, and then injected as treat gas before H-01 furnace. A purge gas stream is vented after 0-03 the cold high pressure drum and before C-02A1B the recycle compressor, controlling the build-up of contaminates and hydrogen sulphide.

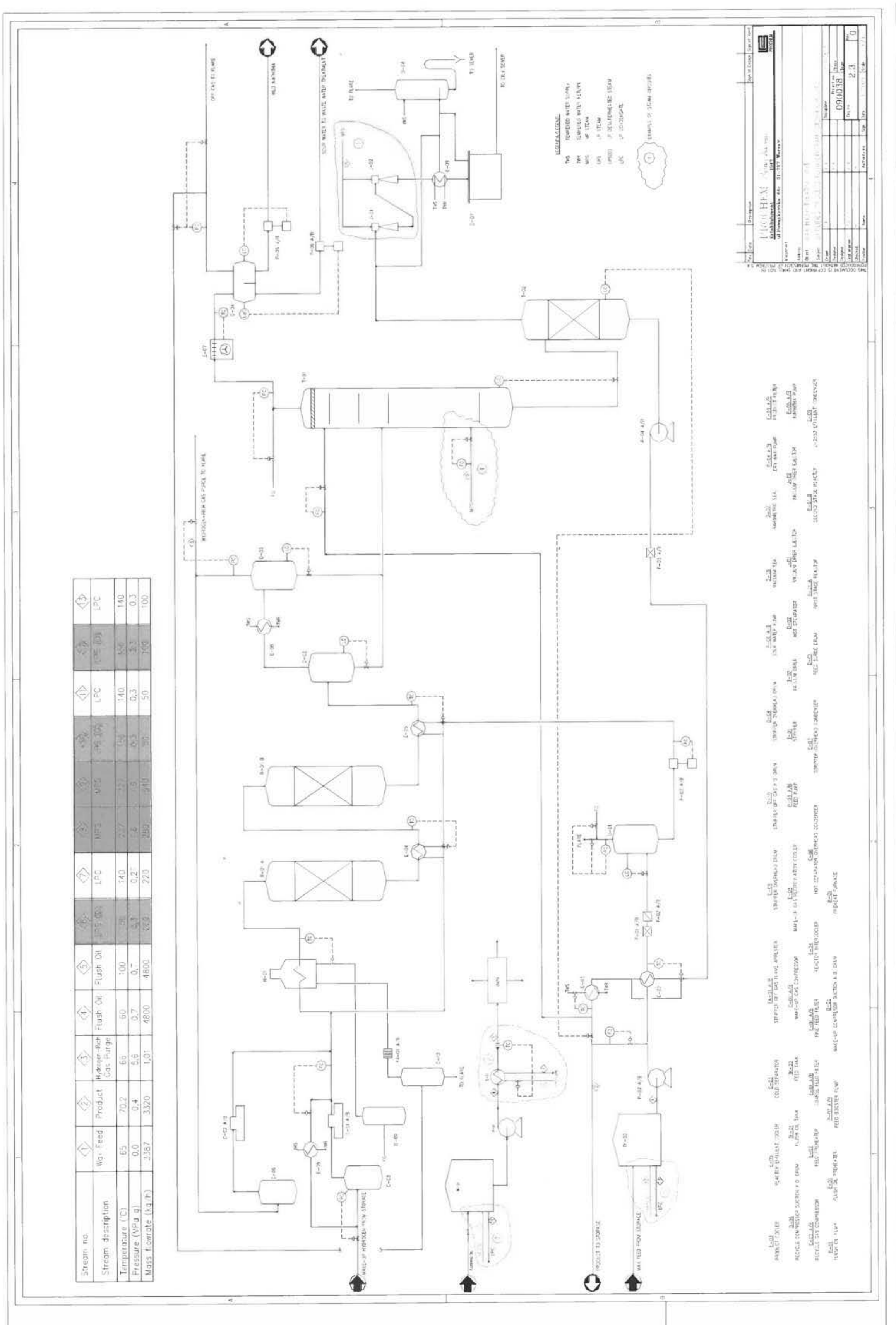


Figure 5-2 : Wax Hydrotreating Simplified Process Flow Diagram

The liquid wax stream from both separators is sent under level control to T -01 stripper. The separated wax is steam stripped in T-01 with MP steam. Stripping steam is injected under flow control. The recommended flow of MP steam is from 60 to 120 kg per cubic meter of wax feed to stripper. Stripper T-01 removes any remaining dissolved treat gas and light hydrocarbons formed in the reactor. The overhead stream from the stripper consists of low pressure tail gas, sour water and the light naphtha formed in the reactor. It is cooled to 40°C and partially condensed in E-07 air cooler. The low pressure off-gas, sour water and wild naphtha are separated in 0-04 stripper overhead drum. The off-gas is sent to H-01 furnace burner under pressure control and excess of gas is sent to the flare on split range under pressure control.

The liquid wax from stripper bottom flows to T -02 vacuum drier under level control where water is removed to give water free and haze free wax product. The vacuum drier operates at 60 mbar absolute vacuum. Vacuum is pulled by vacuum drier ejectors J-01/J-02 and regulated by pressure controller. The MP steam from ejectors outlet is condensed in E-09 effluent condenser.

The hot dry wax is pumped under level control through F-03 A/B filter to remove any contaminants down to 5 microns, which are sometimes released from the catalyst. After filtration the hot product wax is exchanged with the feed wax in E-02 feed preheater and then cooled to 70°C in E-03 tempered water cooler. Before sending hydrotreated wax product to storage a continuous injection of oxidation inhibitor is done on line just after the level control valve. Maximum temperature of wax product stored in tanks should not exceed 80°C.

Because of the wax high melting point, before the shutdown of the Unit or the shutdown of individual equipment, process lines and equipment need to be flushed by a hot paraffinic light oil. The flushing oil distribution is composed of storage tank, pump and E-01 preheater using saturated LP steam. The flushing oil is stored at 60°C and supplied to users if needed, at operating pressure of 0.55 MPa(g) and a temperature of 100°C. After use, the flushing oil is sent to regeneration or used for another purposes.

The crystalline wax products meet food-grade waxes of typical 0.5 % oil content with no more than 1.5 % oil content, and less than 20 ppmw sulphur content. The crystalline waxes meet requirements of EU Pharmacopoeia and FDA standards. Waxes can be used as well in food and cosmetic industry.

The above described unit is capable to process 30 000 tons of feedstock per year, if on stream time is the minimum 8000 hours. The total yearly production is 27 000 tons of finished wax products at a design service factor of 91 % and a yield of 98 %.

5.3 HAZARDS OCCURING DURING UNIT OPERATION

Risk of hazards in Wax Hydrotreating Unit can be evaluated as high, due to presence of light hydrocarbons and hydrogen, other flammable gases, process high temperature and pressure. The Unit area is Ex classified. Area detailed classification is specified in relevantHazardous Area classification documents. Possible hazards have been identified in courseof HAZOP report elaborated in two stages and proper measures have been taken duringUnit design to avoid emergency situations and to add additional provisions diminishing riskof hazards. Potential of hazard increases when an emergency occurs. Many factors caninitiate an emergency, as utility failures, operating failures, control system failures.

Fire is a serious hazard in a Wax Hydrotreating Unit. In case of fire an attempt shall be done for ceasing the flow of hydrocarbons to the affected area. If possible, ail liquids to be drained from the affected area into a safe location and emergency depressuring facilities can be used to depressurize the Unit to flare. Unless the fire can be completely contained and controlled without danger to personnel and equipment, the Unit shall be shutdown following the General Emergency Procedure.

Emergency Shutdown system (ESD) is provided to automatically bring the equipment to a safe status in case of abnormal and potentially unsafe operating conditions. The main shutdown system is the depressurizing system for the high pressure sections. This system is activated by the operator in case of extreme emergency, temperature runway, leak or fire. The fired heater is provided with three shutdown systems for the different fuel gas used, i.e. natural gas and off-gas. The critical machinery equipment has its own protective systems provided by suppliers.

Each emergency situation, such as loss of utility, mechanical failure, or leak, will require response of different javel. The type of emergency and its severity will determine the steps that should be taken. General Emergency Shutdown Procedure recommends undertaking the following actions:

1- Shutdown preheat furnace to discontinue heat input to reactors;
2- If feasible, reactors bed shall be cooled by recycling cold products through the feed circuit while continuing hydrogen gas flow. In the event or risk of fire, the feed and hydrogen gas shall be stopped immediately;
3- Depressurize the reaction circuit to both reduce and reactor section pressure and provide flow through the reactor section, adding the cooling of the heater and reactors;

As part of the shutdown procedure, the equipment shall be drained then washed with the flushing oil and gas be freed gradually to flare at well-defined admissible drop of pressure and temperature.

5.4 STEAM CONDITIONS

Steam is supplied to the Battery Limit of Wax Hydrotreating Unit by the Power and Steam Station. Wax Hydrotreating Unit needs steam at two different levels of pressure:

1- Medium Pressure Steam, MP
2- Low Pressure Steam, LP

Table 5-1 : Conditions of steam at Battery Limit of Wax Hydrotreating Unit

Steam description	Operating pressure, MPa (g)			Operating temperature, °C		
	Min.	Norm.	Max.	Min.	Norm.	Max.
Medium Pressure Steam, MP	0.9	1.2	1.6	220	240	260
Low Pressure Steam, LP	0.4	0.6	0.67	200	230	240

Both steams are superheated. Each kind of steam is supplied to Unit's Battery Limit, where cut-of valves, instrument devices and summarizing flow meters are installed. Steam producer is responsible for continuous supply of steam through main pipelines and steam stable conditions.
Superheated LP steam direct application is provided in limited range, as follows:

1- For initial purge of H-2551 combustion chamber and start-up;
2- As snuffing steam in case of H-2551 internal tube rupture;

Superheated LP steam is not used directly for process purposes. First it is transferred into desuperheated (saturated) steam by injection of controlled quantity of softened water. That steam has a stable temperature at 150°C and pressure of 0.3 MPa(g). Saturated Low Pressure Steam is used within Wax Hydrotreating Unit as the only heating medium instead of superheated Low Pressure Steam.

5.5 STEAM FUNCTIONS

Steam supplied by Power and Steam Station has the following functions in the Wax Hydrotreating Process:

1- Source of Desuperheated Low Pressure Steam (D)LP, which is prepared within ISBL of the Unit by softened water injection into Superheated Low Pressure Steam.That steam is used as heating medium for steam tracing of process lines, coils in tanks with feedstock, finished products, flushing oil preheater and mixture of paraffin streams held in intermediate vessels;
2- Medium pulling a vacuum by means of ejectors system;
3- Stripping medium for wax stripper;
4- Medium for equipment steaming before plant turnaround maintenance or individual equipment repair;
5- Medium for initial purge of furnace combustion chamber at start-up;
6- Extinguishing medium for tire and air removal from furnace chamber in case of tube rupture. It is a snuffing steam operated manually by operators, when needed.

Preparation and application of Desuperheated Low Pressure Steam is rarely practiced in crude oil processing. That approach refers to cases when one the main targets are conservation of the products good properties during heating. In case of Wax Hydrotreating Unit application of Desuperheated Low Pressure Steam is recommended because of lower tendency for wax overheating. In consequence of overheating, wax becomes darken and less stable. Additional conditions to avoid spoils of wax properties refer to proper design of heating coil, assurance of wax enough level above the coil and temperature control at set point exceeding wax melting point only slightly.

5.6 STEAM CIRCUITS AND CONSUMPTION

Consumption of steam in Wax Hydrotreating Process Unit is evaluated for the circuits marked in Figure 7. Steam maximum consumption during winter is included in table 4.

Table 5-2 : Consumption of steam in Wax Hydrotreating Process Unit

Steam Circuit N°	Steam consumer/receiver	Steam flowrate kg/h			Steam function	Remarks
		Low Pressure Steam, LP	Low Pressure DesuperheatedSteam, LP(D)*	Medium Pressure Steam, MP		
1	J-01 / J-02 Steam Ejectors	-	-	250	Vacuum pulling in T-02	Dewatered MP Steam
2	E-01 Flushing Oil Preheater	-	220	-	Heating medium	
3	TK-01 Flushing Oil Storage Tank coil	-	50	-	Heating medium	
4	T-01 Wax Stripper	-	-	540	Stripping medium	Dewatered MP Steam
5	TK-02 Feed Tank coil	-	100	-	Heating medium	
	LP Steam Desuperheater	3630**	-	1500		
Total		**3630****	**370**	**820**		

*15 % Steam prepared by softened water injection into LP steam ** LP steam used for preparation of LPdesuperheated (saturated) steam

The LP desuperheated (saturated) steam is prepared by injection of 270 kg of softened water into 3630 kg/h of superheated LP steam. Total quantity is 3900 kg/h. It is the maximum demand for that steam in wintertime, when minimum air temperature can reach minus 30°C. Out of the balance of the above table results that 3 530 kg/h of LP desuperheatedsteam is consumed during winter for heating purposes, particularly for heating of:

1- Feedstock inventory in storage tanks;
2- Product wax in storage tanks;
3- Off-specification wax in intermediate tanks;
4- Operational stock of tempered water;
5- Process lines;
6- Selected items of process equipment;
7- Selected items of field instrumentation;
8- Product wax loading facilities;

5.7 LOCAL STEAM GENERATION

No steam generator is installed in Wax Hydrotreating Unit. However, heat is recovered efficiently from process hot streams mainly for feedstock preheating.

5.8 STEAM FAILURE

Steam failure usually does not result in a Unit shutdown if the failure is of a short duration. During steam failure, the wax stripper operation is affected and ejectors system is not able to pull the vacuum on wax drier. If steam failures take more, no stripped product shall be diverted to off-specification tank or to slop during the period of a short term outage.
If the outage is expected to continue, the Unit shall be put down following the Emergency Shutdown Procedure.

6. CASE STUDY DATA

6.1 PRESENTATION

Prochem gives the data corresponding to 2 different complexes :
- An Oil Refining and Petrochemical Complex
- A Conversion Refinery

For both cases, the characteristics of the Power Station attached to the complex are given, in terms of pressure, temperature, tons per hour.

6.2 OIL REFINING AND PETROCHEMICAL COMPLEX

The Oil Refining and Petrochemical Complex consists of two integrated production centers manufacturing oil products and petrochemicals.
An associated infrastructure supplies utilities to Complex's Units and takes over side streams and wastes for safe disposal.
The Oil Refining and Petrochemical Complex is capable of producing a wide range of premium slates products. The overall operations include the production of transportation fuels, lubricants, polymers and petrochemicals. These products are placed mainly on local market and on the international market place in European countries. There is a possibility of adjusting process parameters and changing of products range in accordance to market demand and new standard quality.

The Complex operates its own Power and Steam Station, which is located within internal boundaries. The Simplified Energy Flow Diagram from Power and Steam Station to the Complex is shown in Figure 6-1.

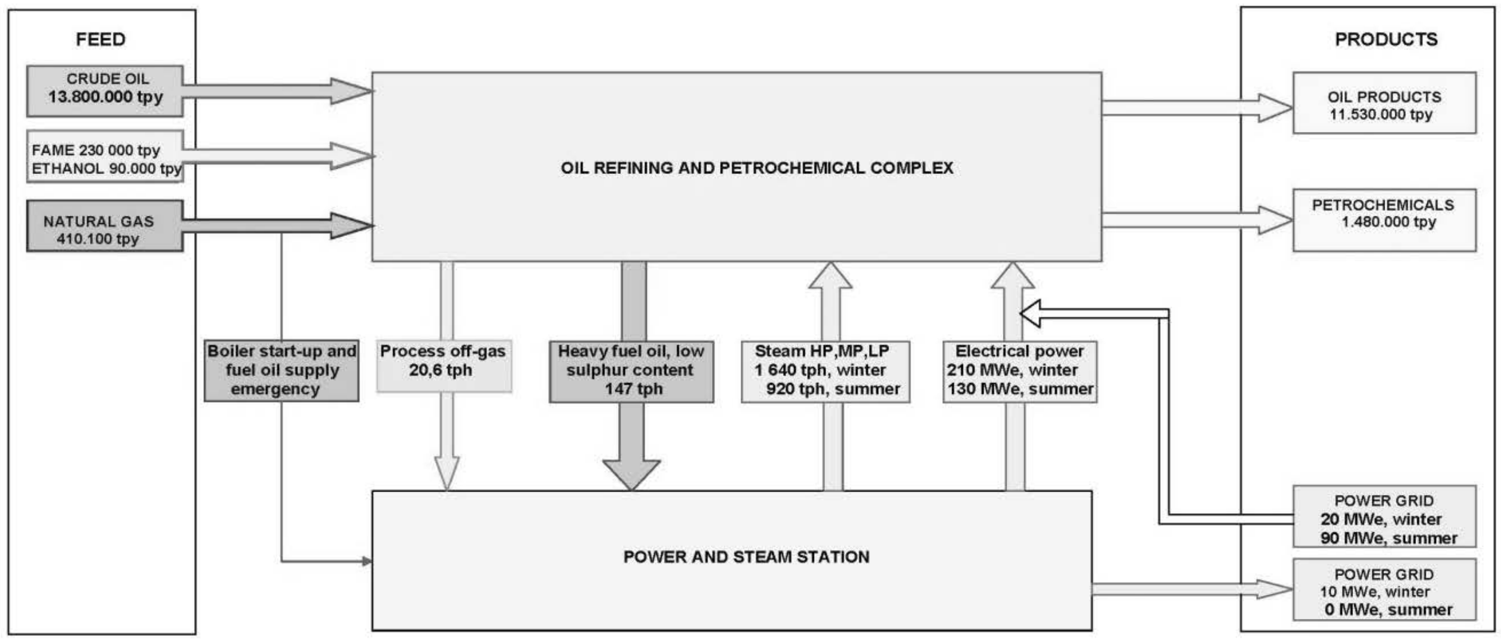
The values included in this diagram are rather informative and may not be in line with a selected existing pattern.

The Power and Steam Station consumes a part of the generated steam and electrical power for its own process needs. The source from which fuel for steam boilers is available are process streams of heavy low sulphur fuel oil and heavy liquid by-products, and process off-gases containing hydrogen, methane and ethane components, which have a caloric value at min. 5250 - 7150 kcal/Nm^3. The average share of fuels consumed by Power and Steam Station is maintained below:

- Heavy low sulphur fuel oil and heavy liquid by-products 88 %
- Process off-gases 12 %

Fuels consumption is not the same all over the year, but it changes following the quantity of steam produced, which is higher during winter and lower in the hot period. The total demand for energy by the Oil Refining and Petrochemical Complex is relatively high, if the quantity of crude oil processed is taken into consideration.

OIL REFINING AND PETROCHEMICAL COMPLEX
SIMPLIFIED ENERGY FLOW DIAGRAM



Steam Boilers Specification

Boiler No	Fuel	Steam outlet, nominal conditions		Steam boiler output, t/h		Boiler operating thermal power, MW
		Temperature, °C	Pressure, MPa(g)	Nominal	Operating	
1	Heavy Fuel Oil, Off-gas	540	13,9	320	290	274
2	Heavy Fuel Oil, Off-gas	540	13,9	320	270	257
3	Heavy Fuel Oil, Off-gas	540	13,9	320	290	274
4	Heavy Fuel Oil	540	13,9	420	370	350
5	Heavy Fuel Oil	540	13,9	420	370	350
6	Heavy Fuel Oil	540	13,9	420	370	350
7	Heavy Fuel Oil	540	13,9	420	370	350
	Total			**2 640**	**2 330**	**2 205**
8 *	Heavy Fuel Oil	440	4,0	200	180	165

* - Peak Demand Steam Boiler

Steam Turbines Specification

Turbine No	Type	Steam inlet, nominal conditions		Turbine nominal power, MWe
		Temperature, °C	Pressure, MPa(g)	
1	Steam extraction / back-pressure	540	13,0	55
2	Steam extraction / back-pressure	540	13,0	55
3	Steam extraction / back-pressure	540	13,0	55
4	Steam extraction / back-pressure	540	13,0	55
5	Steam extraction / back-pressure	540	13,0	55
6	Steam condensing	540	13,0	65
	Total			**340**

Figure 6-1 : Simplified Flow Diagramof the Oil Refining and Petrochemical Complex

Two main factors are responsible for that situation:

- The first one is the further processing of some gases and crude oil distillates in the steam cracker, followed by long chain of petrochemical processes for effective utilization of intermediate products to high value commercial petrochemical products.
- The second one is a high conversion of crude oil heavy distillates and residues to transportation fuel components, which lead to deep and complex crude oil processing expressed by the Nelson Complexity Factor.

That Factor has a value close to 12. The higher Nelson Complexity Factor, the energy consumption is higher. Nevertheless, consumption of energy by the Complex calculated as an equivalent of crude oil necessary for energy generation is approximately 11%, the level commonly acceptable by world refineries. Notice the low consumption of energy by simple Hydroskimming Refinery that will be able to generate poor profit or even losses by reason of lack or low conversion.

Steam flows required by the Complex, except those self-generated in process Units, are produced and supplied from the Power and Steam Station. The demand of the Complex for steam is high during winter season and almost 40% lower in summer time.
In hot days neither operational inventory of crude oil nor distillates, intermediate products and residues, stock of commercial products having pour point temperature above 0°C require heating by steam. In summer time the quantity of steam for compensation of overall losses of heat in production units, off-site infrastructure objects and social premises is much lower than during winter period.
In addition, the consumption of steam during summer is also lower as a consequence of turnaround maintenance of selected production Units, which is usually carried out in that period.
Demand for process steam during winter and summer changes only slightly.
Eight steam boilers are installed in the Power and Steam Station, having a total nominal capacity of 2640 tons per hour of superheated steam at a pressure of 13.9 MPa(g) and a temperature of 540°C.

Among them, 6 - 7 boilers are under operation during winter and 5 - 6 boilers are on stream in course of the summer period.

At least one boiler is continuously kept under hot stand-by conditions.

Steam from boilers is received by headers and supplied first to 5 extraction / back – pressure steam turbines and to one steam condensing turbine.

The first ones can deliver steam at adjusted pressure, which is further reduced down to levels required at separate internal headers supplying steam to production and auxiliary Units, i.e. 7 MPa(g); 4.5 MPa(g); 3.5 MPa(g); 1.7 MPa(g); 0.6 MPa(g). Steam at lowest pressure 0.25 MPa(g) is consumed locally, mainly for heating purposes and Boiler Feed Water degasification.

Main pipelines supplying steam at required pressure to consumers are connected to the relevant headers. The predominant quantity of steam is supplied by the Power and Steam Station to production and auxiliary Units at high pressure (HP), medium pressure (MP) and low pressure (LP). Conditions of those steams at headers are specified in table below.

Table 6-1 : Steam characteristics for the Oil Refining and Petrochemical Complex

Steam description	Pressure, kPa (g)			Temperature, °C		
	Min.	Norm.	Max.	Min.	Norm.	Max.
High Pressure Steam, HP	3000	3100	4000	236	260	320
Medium Pressure Steam, MP	1300	1600	1850	196	220	280
Low Pressure Steam, LP	400	580	850	152	170	230

The steam conditions specified at headers are slightly higher than the ones required by the production Units. The excess of steam pressure and temperature is consumed as losses in course of the steam transportation alongthe main pipelines.

The boilers operating parameters and steam conditions at headers are monitored continuously byDCS. If fluctuations of steam conditions occur, operating conditions of boilers and turbines are properly corrected by operators. Small quantity of steam is supplied outside the Complex Battery Limit to third party consumers on the base of a mutual agreement.

No stand-by conventional steam boiler is installed within the Complex production area, outside the Power and Steam Station.
In some production Units, steam generators are installed, which recover heat from selected process liquid streams and flue gases. Generated steam is usually used inside the production Units. Any surplus of steam can also be injected back intothe network if its conditions are the same or slightly higher than the values specified in the above table. However, the quantity of such generated steam has no important impact on overall balance of steam within the Complex.
In many cases steam received by the production Unit at conditions specified above is additionally superheated or de-superheated before usage in order to meet special process requirements. That situation exists for example in Crude Oil Distillation Units, Lube Base Oil Complex and Paraffin Hydrotreating Units.
In other cases hot oil is used as heat carrier instead of steam, because of a more stable temperature and lower tendency for process media overheating, resulting inquality (color) deterioration.

Nevertheless, the possibility of steam replacement in crude oil processing practically doesn't exist. Steam is a bulk heat carrier, non-toxic, easily transported on long distances in short time and safely operated. It has a high value of enthalpy, which is efficiently transferred to cold media by condensation.

Obviously, usage of steam as heat carrier is predominant, but it has also many other functions in crude oil processing. They have been specified in detail in the process description. In some of them, steam enters into direct contact with the process media, in other ones steam takes a part in the chemical reactions, modifying their equilibrium and performances. Further functions of steam refer to periodically executed operations during Unit normal operations, process disturbances and preparation for turnaround maintenance. All these functions of steam are extremely important for Unit smooth operation, performances and safety.

Recoverable steam condensate is approximately 75 % of indirect steam usage (i.e. in heat exchangers, steam tracing and others). Direct steam injected into the process (i.e. stripping, ejectors) and not used in chemical reactions (such as a steam reformer) is recovered as sour (oily) water.

The electrical power requirements for the Complex range from 220 MWein course of summer to 230 MWeduring winter. The required electrical power is covered mainly by the own production of the Power and Steam Station and only balanced by a supply from the Power Grid.

Own generation of power by the Power and Steam Station is much lower during summer, as a consequences of lower demand for Low Pressure Steam, followed by a reduced utilization ratio of the 5 existing extraction / back-pressure steam turbines. During the summer period only the steam condensing turbine can be operated at nominal capacity.

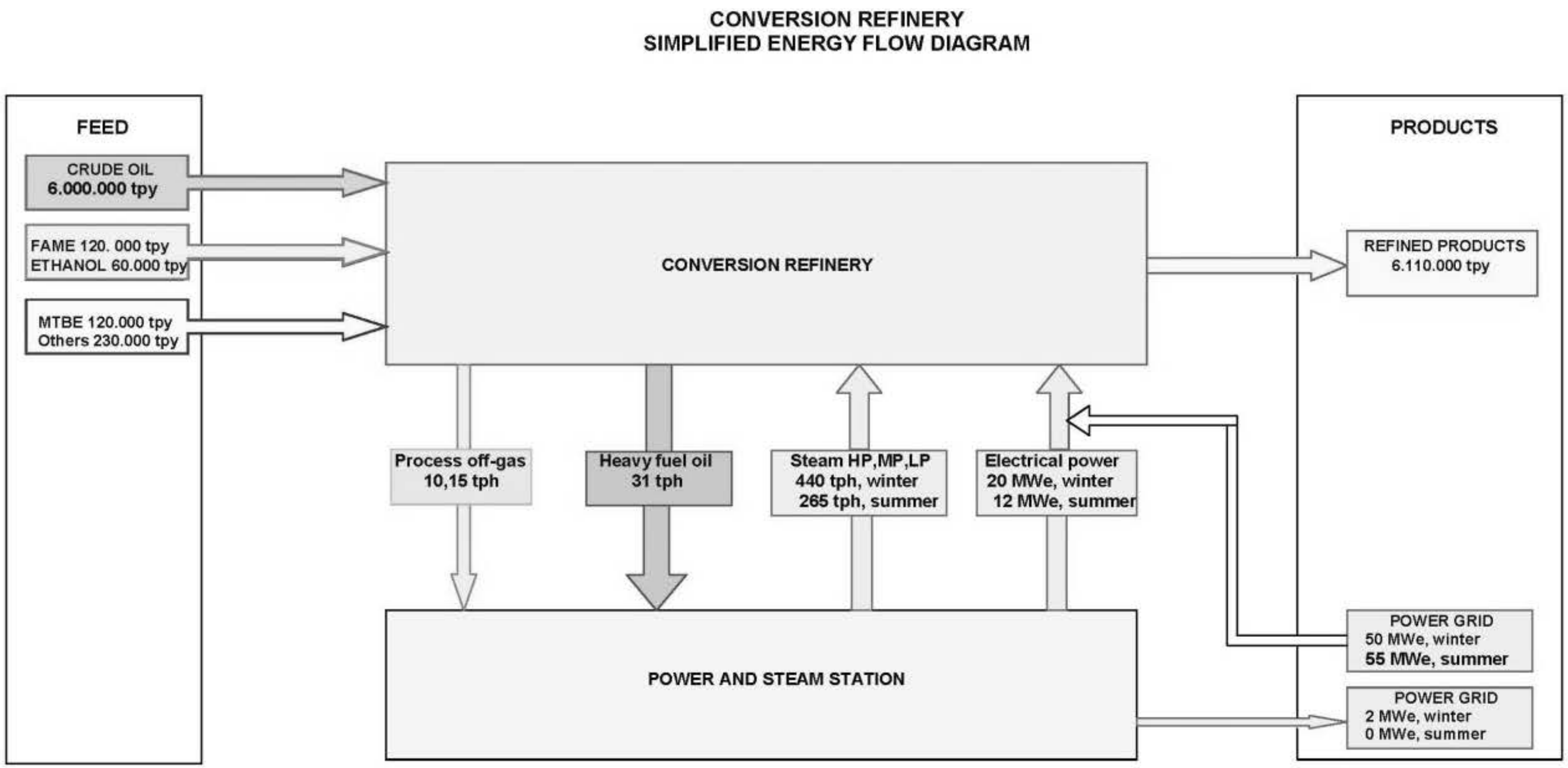
In accordance to the Refinery and Petrochemical Complex operating requirements and safety, the balance of electrical power demand shall be covered totally by power supplied from the Power Grid.
Uninterrupted supply of electrical power to the whole Complex, first of all to production Units and Utilities, has a critical importance for safety.
Disturbances in power supply and in operation of Complex internal distribution system can lead to serious emergency problems.
The standard safety recommendations for refineries and petrochemical complexes require at least two independent power supplying lines from Power Grid to Complex Main Substations; each of them shall have at least two independent industrial source generating power.

Steam turbine generators operated by the Complex cannot taken into consideration as an independent source of power. The base equipment installed in Fire Fighting System usually has its own independent emergency power generator. Similar approach is sometimes applied to selected items of equipment in case of critical importance for a safe shutdown of the Unit.

7. CONVERSION REFINERY

The Conversion Refinery is able to process above 6 million tpy of Russian Export Blend Crude Oil or similar high sulphur crudes. There is also the possibility of processing Arabian Light Crude or alternatively light low sulphur crude, for which Brent Blend or Statfjord crude is taken as an example. The Refinery is capable of processing crude oils in blended operation, unless it is shown to be uneconomical.

The technical configuration of the Refinery includes Units of Crude Oil Distillation, Naphtha Hydrotreater, Gasoil Hydrodesulphurisation, Heavy Distillates Hydrocracker, Light Naphtha Isomerisation, Medium Naphtha Reformer, Kerosene Treatment, Bitumen Blowing, Lube Oils, Sulphur Recovery, Hydrogen Generator, and Fuels Blending. Nelson Complexity Factor of the Refinery is evaluated below 10.
The Simplified Energy Flow Diagram from the Power and Steam Station of the Refinery is included in Figure 7-1.



Steam Boilers Specification

Boiler No	Fuel	Steam outlet, nominal conditions		Steam boiler output, t/h		Boiler operating thermal power, MW
		Temperature, °C	Pressure, MPa(g)	Nominal	Operating	
1	Heavy Fuel Oil, Off-gas	510	7,9	160	144	137
2	Heavy Fuel Oil, Off-gas	510	7,9	160	144	137
3	Heavy Fuel Oil	510	8,0	145	130	123
4	Heavy Fuel Oil	510	8,0	145	130	123
	Total			**610**	**548**	**520**

Steam Turbines Specification

Turbine No	Type	Steam inlet nominal data		Turbine nominal power, MWe
		Temperature, °C	Pressure, MPa(g)	
1	Steam extraction / back-pressure	510	8,0	15
2	Steam extraction / back-pressure	510	8,0	15
	Total			30

Figure 7-1 : Simplified Flow Diagram of the Conversion Refinery

The steam quantities required for the refinery, except those self-generated by the refinery process Units, are supplied by the Power and Steam Station, which is located in neighbouring area.

The electrical power for the refinery is supplied in small quantity from the Power and Steam Station, and balanced by the Power Grid.
An emergency generator is provided in the Power and Steam Station.
No standby conventional steam boiler is installed within production area, outside the Power and Steam Station.
In some production Units, steam generators are installed, which recover heat from selected process streams and flue gases. Generated steam is usually used inside the production Units.

Two kinds of fuel systems exist in the Refinery, the Fuel Gas System and the Fuel Oil System. The Fuel Gas System collects off-gases from process Units.
In addition to the above, the LPG vaporizer is provided as a backup system in case of a start-up operation, shortage in fuel gas and for disposal of off-specification LPG product.
The Fuel Oil System is designed to handle medium sulphur heavy fuel oil, some heavy by-products or residues from refining processes as fuel oil, and supplies it to the Power and Steam Station. A part of those fuels is delivered to the process heaters at sufficient temperature and pressure for burning. Steam is also injected in the burners to enhance oil atomizing and combustion.

The Power and Steam Station operates on the basis of the fuels supplied by the Refinery, i.e.:

1. Medium sulphur heavy fuel oil or its blend mixture with some heavy by-products from refining process or residues from these processes;
2. Refinery off-gases, including hydrogen and light gaseous hydrocarbons, which have a caloric value of 10 700 kcal/kg or lower;

Four steam boilers are installed within the Power and Steam Station. They generate superheated steam at a pressure of 8 MPa(g) and a temperature of 510 °C. Three operating boilers ensure the quantity of steam required by the Conversion Refinery, while one boiler is kept under hot standby conditions.
Overhaul of boilers is usually planed in course of summer, when demand for steam is lower.

The steam management within the Power and Steam Station is similar to the one discussed in the above for the Oil Refinery and Petrochemical Complex.

8. SUMMARY OF THE MAIN RESULTS

The teachings of this case study can be summarized as follows:

- Steam is mostly used at 3 different pressure levels , high pressure (about 30 bars – 260°C), medium pressure (about 16 bars – 220°C), low pressure (about 4 bars – 200°C)
- The steam is mostly generated in a dedicated Power and Steam Station, at high conditions (about 130 bars – 540°C). The steam is first expanded in turbines to produce electricity, then admitted into the different pipe headers.
- The steam is frequently in direct contact with the products
- Most of the steam condensates are discharged into the environment, only a fraction returns to the boilers water preparation plant

- A large part of the steam consumption is linked to heating of equipment and infrastructures which must be maintained at a sufficient temperature in winter. As a result, steam consumption is markedly reduced in summer
- Stable steam conditions are most frequently compulsory for a safe and smooth operation. Sudden interruptions may lead not only into production problems, but also into emergency measures. For this reason, the power plant always maintains several boilers into operation, with at least another one in standby mode ready to take-over.

9. HTR POTENTIAL INTEGRATION INTO THE COMPLEXES

9.1 OIL REFINING AND PETROCHEMICAL COMPLEX

The large size of the complex gives the potential feasibility to incorporate a HTR into the heat and power supply system.

Examination of Figure 6-1 shows that:

- The total steam production capacity of the 7 boilers is 2640 t/h, or 733 kg/s,
- Steam consumption is 1640 t/h (455 kg/s) in winter and 920 t/h (255 kg/s) in summer
- Electrical demand is 230MWe in winter and 220MWe in summer

If a HTR is introduced, it should logically be operated at full capacity all the year.

Let us consider the HTR described by Westinghouse in Appendix A. It has a power of 520 MWth. This reactor can supply a Combined Heat and Power plant able to deliver 236 MW of electricity and 80 kg/s of HP and MP steam.

The HTR Power station covers slightly more than the need of electricity of the complex in winter (230MWe) and about 31% of the steam demand in summer.

The Power station would have to sell electricity to the grid, especially in summer.
The conventional boilers will still be used to provide the balance of steam.

In a refinery, the off-gases produced by some process units must be eliminated (See for instance Figure 2.1 in this document). The best solution is to use them as fuel in some of the boilers. This means that conventional boilers must still be used, even after the introduction of a HTR heat source.

The conventional boilers also provide a backup facility, in case of interruption of the HTR for maintenance or for other reasons.

The introduction of a HTR requires a complete redesign of the Power and Steam station.

9.2 CONVERSION REFINERY

If we assume that the Conversion Refinery is separated from the Oil Refining and Petrochemical Complex considered in the above, a similar analysis can be made.

Figure 7-1 shows that for the Conversion Refinery :

- The steam demand is:
    - 440 t/h (122 kg/s) in winter
    - 265 t/h (74 kg/s) in summer
- The electricity demand is:
    - 70 MWe in winter
    - 67 MWe in summer

A similar HTR Combined Heat and Power Station would deliver too much steam, because conventional boilers must be retained to eliminate the off-gases and for backup purposes.

A design different from the one proposed in this deliverable would be required.

It could for example be a Power station designed with a steam turbine generator producing mainly electricity. The turbine would include some extraction for HP and MP steam.
A complete separated study would be necessary to obtain more details.

The introduction of a HTR would require a complete redesign of the Power and Steam station. This station would be a net electricity producer, contrary to the present situation.

10. CONCLUSIONS

The case study provided by PROCHEM shows that HTR can be technically integrated in large chemical complexes.

The HTR delivers steam which can be injected into the existing steam network, without any change, seen from the different process units.

The nuclear source can only pretend to cover a part of the local heat demand, because off-gases must be incinerated anyway, and backup boilers are required.

The introduction of a HTR leads to a complete redesign of the Power and Steam station. The corresponding investment must find its justification through sufficiently attractive benefits.