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D4.41 – General specifications of a demonstrator

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Summary

Current sources for process heat in Europe are mostly dependent on fossil fuels: Oil, gas, coal. Light water reactor (LWR) technology is not suited to meeting needs for higher temperature applications, i.e. in chemical processes.

Considering the potential of High Temperature Reactors to supply high temperature process heat, many different applications exist. A few of these include oil refining, chemical processing, heavy oil recovery, tar sands oil recovery, hydrogen production, etc.

The potential applications cover a wide range of necessary temperature. Conventional HTRs would likely serve moderate temperature applications up to about 700°C, while other applications might require a Very High Temperature Reactor (VHTR). If the appropriate HTR nuclear heat source were ready today, some of these applications would be ready for immediate deployment, while others would still require years of development on the process application side.

The purpose of this document is to present a clear and complete statement from utility perspective for initiating a cogeneration project based on a High Temperature Reactor, and propose a set of a generic of requirements applicable to a project in Europe, based on experience feedback from previous HTR and cogeneration projects, findings highlighted in the frame of European projects (e.g. NC2I, Europairs, Archer), potential synergies with other nuclear cogeneration programs (e.g. NGNP Alliance) and current requirements and potential trends for future nuclear plants in Europe.

Approval

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1 Introduction

The purpose of this document is to present a clear and complete statement from utility perspective for initiating a cogeneration project based on a High Temperature Reactor (HTR). This document consists of a generic power plant and cogeneration specification.

The requirements are grounded on:

- Experience feedback from previous HTR and cogeneration projects
- Findings highlighted in the frame of European projects (e.g. NC2I, Europairs, Archer)
- Potential synergies with other nuclear cogeneration programs (e.g. NGNP Alliance)
- Current requirements and potential trends for future nuclear plants in Europe
- Specifics related to new nuclear design development

The anticipated uses of this document are following:

- Provide a common frame for the development of HTRs for cogeneration purposes, so as to allow the emergence of standardized HTRs designs that would be well fitted to the European needs and that could be proposed throughout Europe without any major design change,
- Provide all stakeholders with a tool for harmonization of the rules (groups of laws, decrees, regulations and Codes and Standards which are required for e.g. nuclear safety, connection to HV grid...) on the European unified electricity and heat market.
- Provide a basis for investigating technical and economic aspects of a nuclear cogeneration project, in order to support the decision-making process.

This document emphasizes on those areas which are most important to the objective of achieving a nuclear cogeneration plant which is optimized with respect to safety, performance, and economics.

It evaluates technical and economic aspects of nuclear cogeneration, and proposes general orientations for end-users configurations.

It proposes generic requirements and preferences with regard to economics and performance of the plant from an end-user perspective. It also includes cover data collected in the frame of the site mapping.

It details safety and licensing aspects. These requirements may be similar to the ones applicable to Light Water Reactors or specific to High Temperature Reactors and cogeneration plant. They also integrate current trends related to nuclear licensing in Europe. Whenever possible, convergence toward international standards will be promoted, in order to favor deployment outside of Europe.

In order to facilitate evolutions or further broadening of this document, the requirements will link to several main “project value drivers”. Requirements will be justified by either an analysis or link to regulations or other codes and standards.

This document aims to have a core of strong generic requirements expressed as objectives or functions as far as possible. Several of these requirements are kept open, i.e. they provide only a design methodology and objectives that can be implemented in several ways by the plant designer.

2 Objectives of a cogeneration demonstrator for process heat

Several projects, many being described in (NC2I-R - D2.11, 2014), have proven the feasibility of nuclear cogeneration. Most of the applications are supplying low temperature heat.

Beyond test runs in small scale HTRs, no nuclear cogeneration to supply process heat for industrial purposes has operated.

Therefore, a cogeneration HTR should achieve several goals in order to demonstrate the suitability for large deployment, in substitution to fossil fuels. These goals are listed as following:

2.1 Demonstrate inherent safety features

Aftermath the Fukushima nuclear accident, renewing public acceptance for nuclear technology is one of the main challenges faced by the nuclear industry. Major issues related to public acceptance of nuclear industry are safety, non-proliferation, and nuclear waste.

HTRs could significantly improve public acceptance compared to existing reactors, given the potential for inherent safety features: they guarantee that under all conceivable accident scenarios, the maximum fuel element temperatures will never surpass its design limit temperature, without employing any dedicated and special emergency systems (e.g. core cooling systems or special shut-down systems…). This ensures that severe accidents are not possible, and therefore unacceptable releases of radioactive products into the environment are eliminated by design.

The main inherent safety characteristics of the HTR are the result of several design features, e.g.:

- Use of coated fuel particles embedded in a graphite matrix which retains the fission products. Kernels coated with carbon and silicon carbide (SiC) have greater heat-resistance than those coated with metallic materials providing a unique robustness of the first barrier
- Strong negative temperature coefficient of the core, which tends to passively shut down the reactor with relatively modest temperature rise above normal temperature
- Very slow temperature transient of the reactor if active cooling of the core is lost. This is made possible by the high thermal inertia of the graphite and the core structure, and the low power density of the core
- Possibility for passive core cooling. The core can be configured to have a large core surface-to-volume ratio. Combined with the low power density, this makes possible passive heat removal (by thermal radiation, heat conduction and free convection) from the core and the outer surface of the pressure vessel, even under the worst accident conditions. Furthermore, in these conditions the maximum fuel temperature can be maintained below the integrity limit of the ceramic-coated fuel.

2.2 Demonstrate economical viability

HTR technology is able to supply energy under different forms: electricity, process or fresh steam, without CO2 emission. With the current objectives in greenhouse gas reduction, HTR and nuclear cogeneration is an opportunity offering the following benefits:

- Increased efficiency of energy conversion and use, minimizing impact of operation on the environment (CO_2, fuel consumption, heat released to heat sink…)
- Opportunity to move towards more decentralized forms of energy generation, where plants are designed to meet the needs of local consumers, providing high efficiency with more integrated production scheme, avoiding transmission losses and increasing flexibility in system use.
- Provide a predictable energy source, with possibility to balance intermittent sources of electricity
- Address different markets and reduce potential competition with current energy sources
- Support the deployment of future technologies such as Hydrogen production

From a governmental perspective, additional benefits from nuclear HTR cogeneration are:

- Increase energy independence substituting fossil fuel as heat source and producing primary fuels (syngas or synthetic fuel)
- Support economy with job creation.

It is likely that a first HTR project will be supported by a governmental entity, so that the "first mover" owner can always maintain the plant operation and obtain investment recovery. However, this government-supported demonstration plant has to ensure that a cost overrun during the construction period will be avoided and that the predicted smooth operation and performance will be kept.

Hence, the demonstration plant must clearly prove that follow-on HTR plants will be competitive comparing to other technologies without any government support.

2.3 Validate technical concepts, prove technology

The technology for HTRs has been established in former plants (DRAGON, Peach Bottom, AVR, THTR, and Fort St. Vrain). In addition, possibilities for higher temperatures have been studied (e.g. in Gas-Turbine-Modular Helium Reactor –GTMHR- project) and tested, e.g. with the Japanese HTTR and Chinese HTR-10 projects operating with an outlet temperature of more than 900°C. Therefore, a wide range of operation possibilities makes suitable HTR technology as energy source for various industrial needs.

IAEA document (IAEA - NG-T-3.10, 2010) insists on evaluating the novelty of the design, the extent to which it is based on previous proven designs, the experience of the manufacturers and, derive from these factors, a view on the safety, reliability and availability of the plant.

It aims to reduce plant owner risk by ensuring cost control, schedule compliance, quality and reliable operation of the plant.

With the objective of marketing a nuclear cogeneration plant, a demonstrator shall build on previous HTR projects (use of structures, systems and components, and design and analysis methods and techniques, featuring characteristics, materials, manufacturing processes, working conditions and plant environment conditions that are identical or similar to those that have demonstrated successful operation), but also provide a basis for further developments (e.g. higher outlet temperatures).

In order to minimize technical risks for a demonstrator, a first project is expected to operate with a steam cycle up to 750°C for the purpose of process steam generation up to 600°C (also called Steam-class). However, to allow evolutions with improved characteristics or different uses, the demonstration plant shall ensure the following:

- Plant design and construction ensure a smooth operation with an acceptable failure rate
- Systems and components' behavior is satisfactory, and provides a basis for future project with similar conditions
- Extrapolation of the design, size, capacity, duty, etc. of systems to a reasonable extend is possible
- Safety systems and components are thoroughly tested approved by the safety authority
- Provide a construction cost baseline as a first step towards a design-to-cost specification for a NOAK system

2.4 Develop the supply chain and skills

One of the lessons-learnt from current nuclear projects is the crucial importance of the supply-chain, to ensure a high level of quality during manufacturing, and therefore obtain a smooth project implementation.

It is widely recognized that strong project and program management capability, provided by a combination of the developers' own in-house resources, those of main contractors and support from external consultancy advice, will be critical to the successful delivery of a new build program, bearing in mind the scale and complexity of the challenge.

For a small number of key items –mostly reactor pressure boundary associated with large forgings, only a few companies in the world have the capability to deliver. However, this capability has been lost or reduced following a long period without nuclear construction, especially without HTR projects.

The companies participating to the supply chain need to make timely strategic investments to build or rebuild its capability and capacity to compete for emerging opportunities. Indeed, the demonstration plant shall also be the demonstration of the readiness to supply, with the highest safety standards systems and components for future cogeneration projects.

The development of the supply chain contributes to the EU objectives of maintaining and increasing technology and manufacturing capability, and thereby creating jobs.

3 Key drivers to define requirements

The deliverable (NC2I-R - D4.11, 2015) identified the main drivers for the profitability of a HTR cogeneration plant for industrial heat supply. Additionally, deliverable (NC2I-R - D4.21, 2015) provided a comprehensive list of industrial sites in Europe, and provided data on their heat and electricity consumption, in order to identify potential sites and uses for a cogeneration plant.

This chapter aims to build on these results to evaluate the key drivers of a nuclear cogeneration project. Following parameters are investigated:

- Market conditions, revenues stream for a nuclear cogeneration project
- Energy needs of industrial sites in Europe
- Potential applications for cogeneration (current applications, future markets)
- Tentative grid stabilization and energy storage aspects
- Current requirements for nuclear power plants in Europe and Synergies with US-NGNP program

3.1 Market conditions, revenues stream for nuclear cogeneration

The deliverable (NC2I-R - D4.11, 2015) identified the main drivers for the profitability of a HTR cogeneration plant for industrial heat supply.

An outcome of the analysis, based on the reference plant, is the relative preponderance of heat revenues over electricity revenues. As visible on the graph presented in **Figure 1**, the slope for heat price evolution is significantly higher than the one for electricity that confirms a higher influence on the profitability of the project.

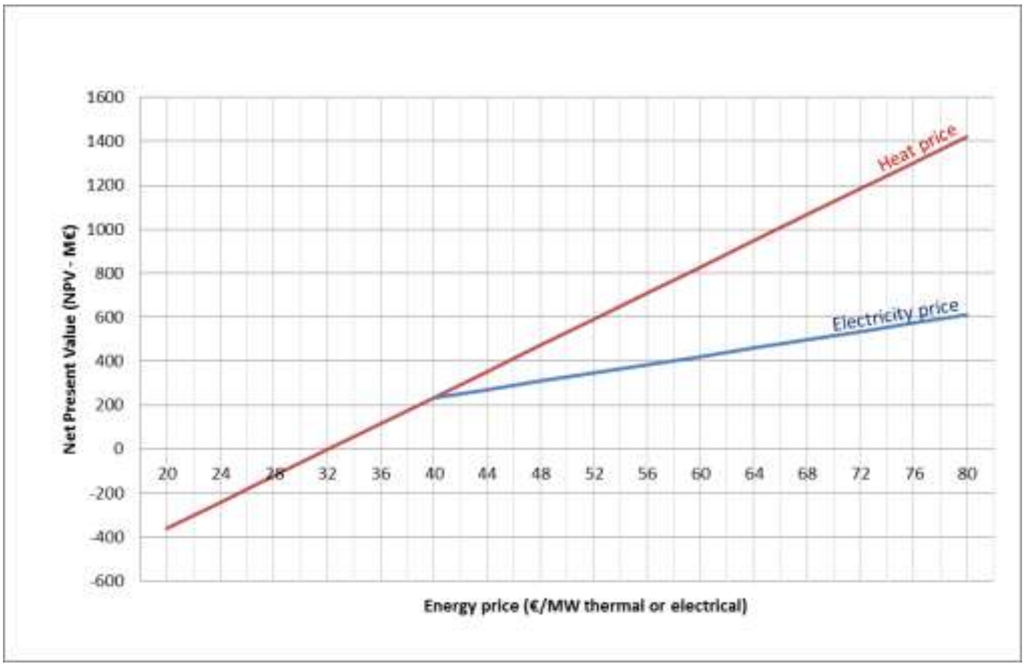


Figure 1 – Sensitivity of the NPV to Heat and Electricity prices

Long-term forecast for energy prices show higher probability of increasing heat price than electricity prices. According to the document "EU energy, transport and GHG emissions – trends to 2050" (European Commission, 2013) main grounds for such forecast are:

Electricity prices:

Power generation costs are forecasted to significantly increase by 2020 in Europe, mainly as a consequence of higher investments due to the need for significant capital replacement and higher fuel costs (because of the large increase in international fossil fuel prices). Grid costs also increase to recover high investment costs in grid reinforcements and interconnectors, which are fully consistent with the provisions of the ENTSO-E TYNDP as well as the achievement of the RES 2020 target.

Smaller components of the cost increase are national taxes and Emission Trading Scheme (ETS) allowance expenditures.

Beyond 2020, average electricity prices remain broadly stable up to 2035 and then are projected to moderately decrease up to 2050 as the benefits, in terms of fuel cost savings, resulting from the enormous restructuring investments in electricity supply come increasingly to the fore.

In addition, lower technology costs from technology progress and learning over time help contain electricity prices together with deceleration of gas price increase.

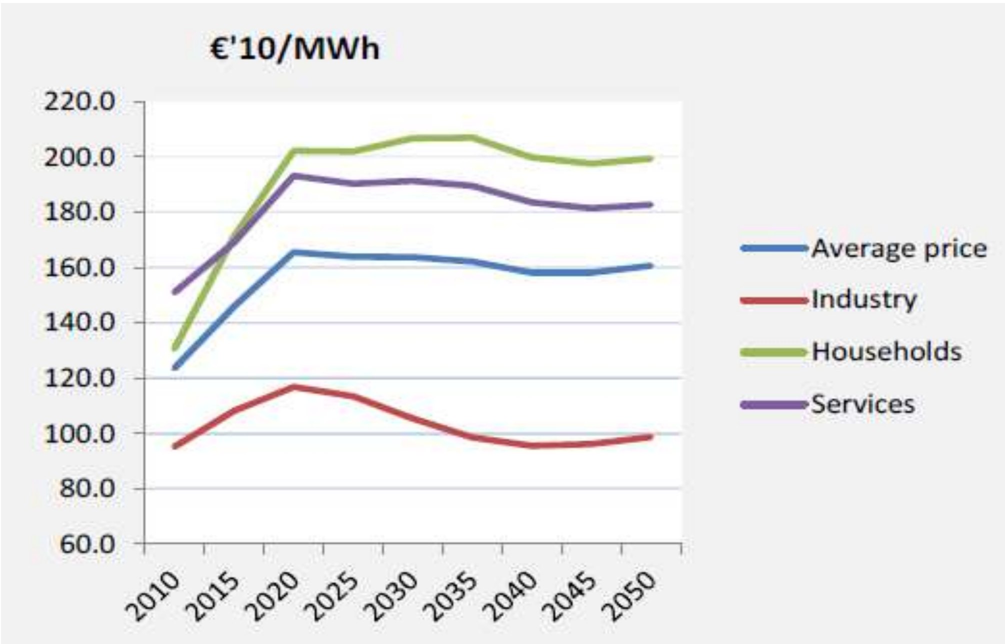


Figure 2 – Electricity price forecast

Source: EU energy, transport and GHG emissions – trends to 2050 (European Commission, 2013)

Note: it is important to note that prices presented in **Figure 2**, include production costs as well as distributions and taxes. When selling electricity to grid, revenues are expected to be 40% to 60% lower.

Heat prices:

The price breakdown for heat production has four main components: Capital, O&M, Fuel and ETS costs.

The relative influence of each is presented in **Figure 3**, which shows the preponderant importance of fuel and ETS prices. A first outcome is the difference between coal and gas: Coal-based energy produces about twice CO2 as gas, therefore ETS costs has a preponderant effect on its price

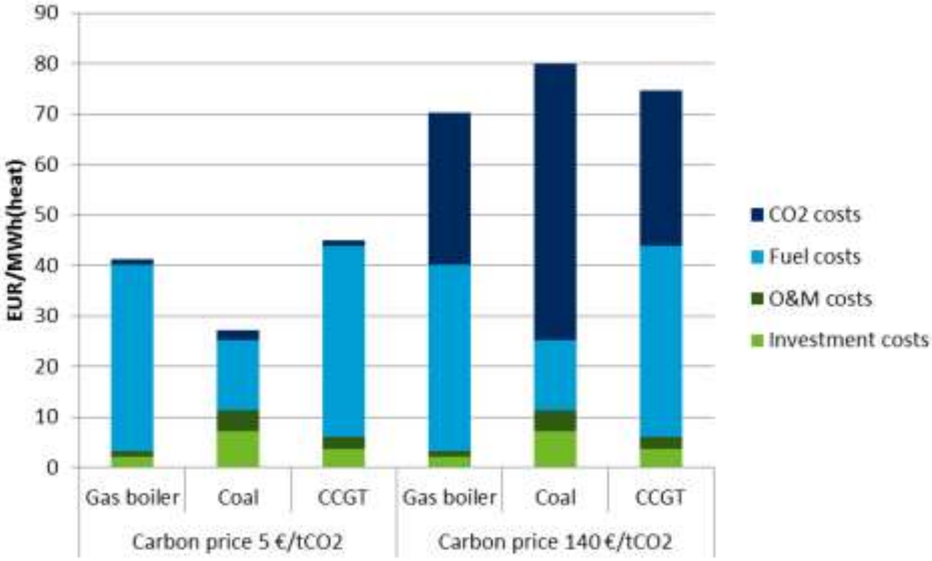


Figure 3 – Heat price to produce the steam or heat needed in the process industry

Source: Word Energy Outlook 2014

A more detailed analysis on the forecast for these 2 main costs will give the probable trend for heat price evolution in the future.

Fossil Fuels

The world fossil fuel price projections were recently revised, including shale gas and other unconventional hydrocarbons reserves, world economic developments and reflection of the Copenhagen/Cancun pledges.

Large upward revisions for conventional gas and oil resources availability have been implemented in the models, as well as the inclusion of worldwide estimates of unconventional gas resources. This change has important implications on prices. In addition, economic drivers, overall higher GDP growth is projected (China, India and Middle East and North Africa regions).

Apart from the EU, no additional climate related policies are assumed for the period beyond 2030.

For oil prince, short-term prices reflect failure of productive capacity to grow in line with demand. The situation eases somewhat around 2020 before declining resource/production ratios resulting in resumption of upward trend in prices.

In the longer term, gas prices do not follow the upward trend of oil price. This is mostly due to the very large additional undiscovered resources that were factored in, including unconventional gas. More importantly, natural gas prices stabilize at a level that is still high enough to ensure economic viability of unconventional gas projects.

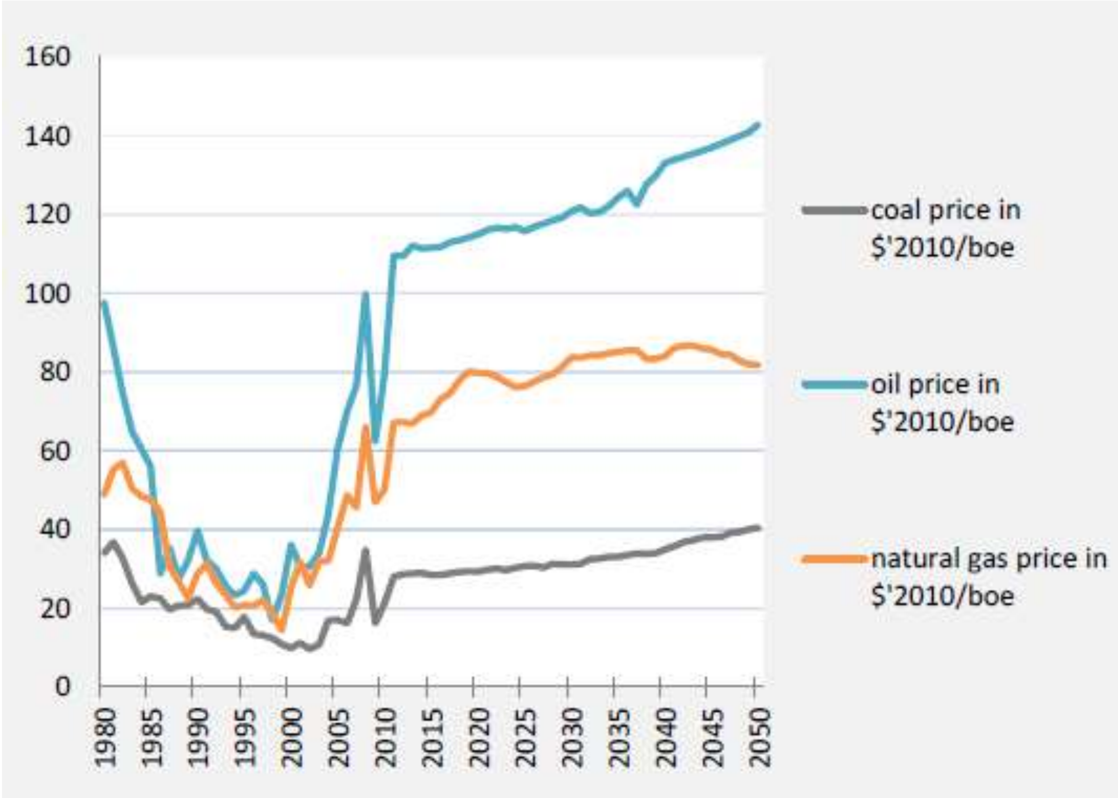


Figure 4 – Fossil fuel import prices

Source: EU energy, transport and GHG emissions – trends to 2050 (European Commission, 2013)

European Union Emission Trading Scheme

International credits, currently priced at very low levels, are expected to be used in the period until 2020, and reach the maximum permissible amount.

ETS prices are endogenously derived so as the cumulative ETS cap is met; the continuously decreasing number of available allowances combined with the significant allowance surplus which is only projected to decrease after 2020 suggest that the ETS price will follow only a slowly increasing trend until 2025 and stronger increases thereafter

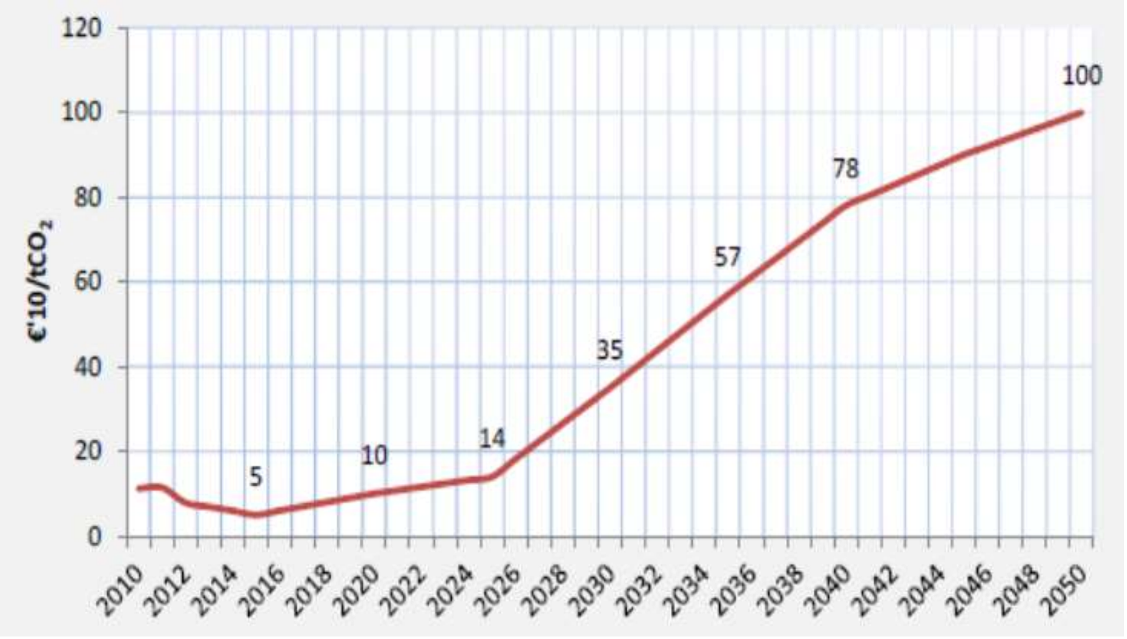


Figure 5 – Projection of the ETS prices
Source: EU energy, transport and GHG emissions – trends to 2050

The heat prices resulting fuel and CO2 prices can be calculated for different fuels with the model developed for deliverable (NC2I-R - D4.11, 2015). Prices input in the model are the forecasts from (European Commission, 2013) shown on **Figure 4** and **Figure 5**, and summarized in the following table. Spots represent the forecast at different period of time.

Item	Current price	Forecast 2020	Forecast 2030	Forecast 2040
Oil (€/MW.h)	38,1	70,6	73,7	81,1
Gas (€/MW.h)	21	49,1	52,2	52,2
Coal (€/MW.h)	18,4	18,4	19,7	21,5
CO_2 (€/t)	7	10	35	78

Table 1: Forecast for fuel and ETS prices

Results of the calculations are presented in the **Figure 6**, **Figure 7**, **Figure 8** hereafter. It is important to note that following calculations are based on average values from European Commission. Forecast might differ significantly with:

- The proper resources of a country, and its policy about their use
- The CO2 policy of a country (e.g. countries from the Annex I of Kyoto protocol)
- The Tax and subventions levels applied to energy sector

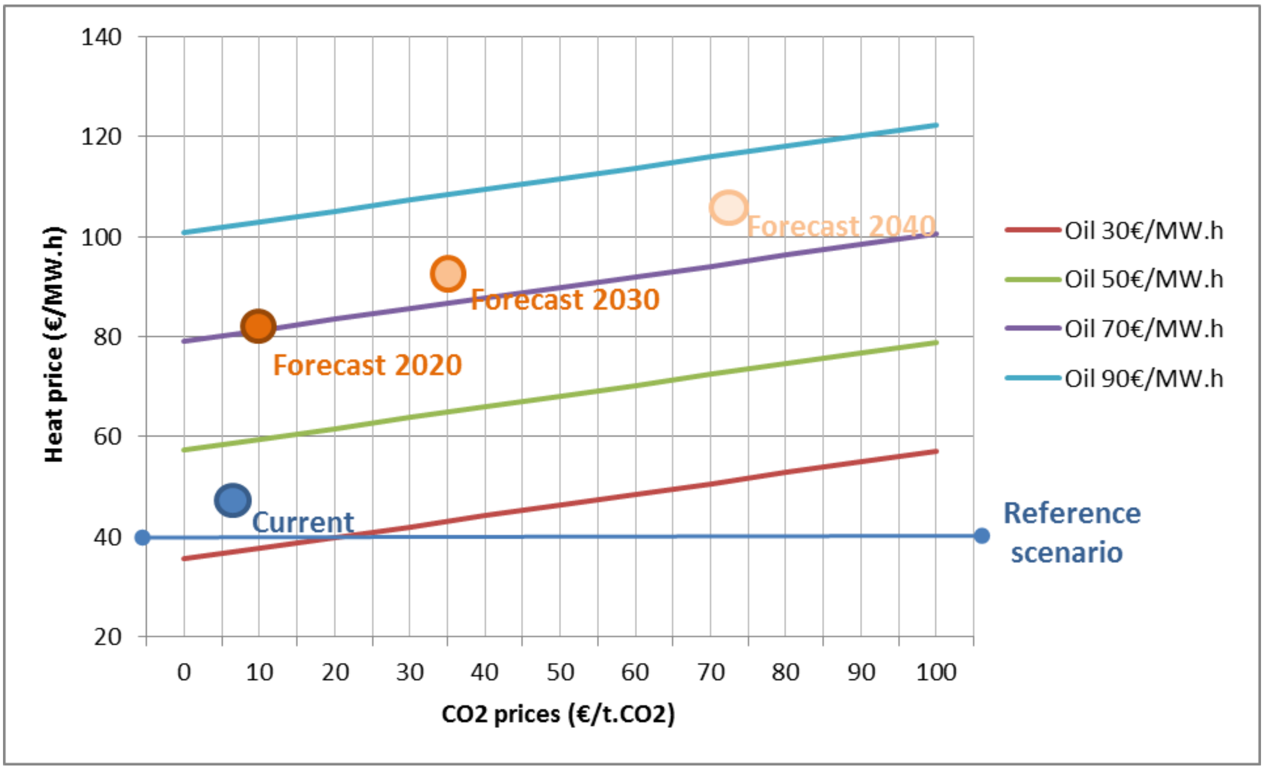


Figure 6 – Influence of Oil and CO2 prices on the heat price

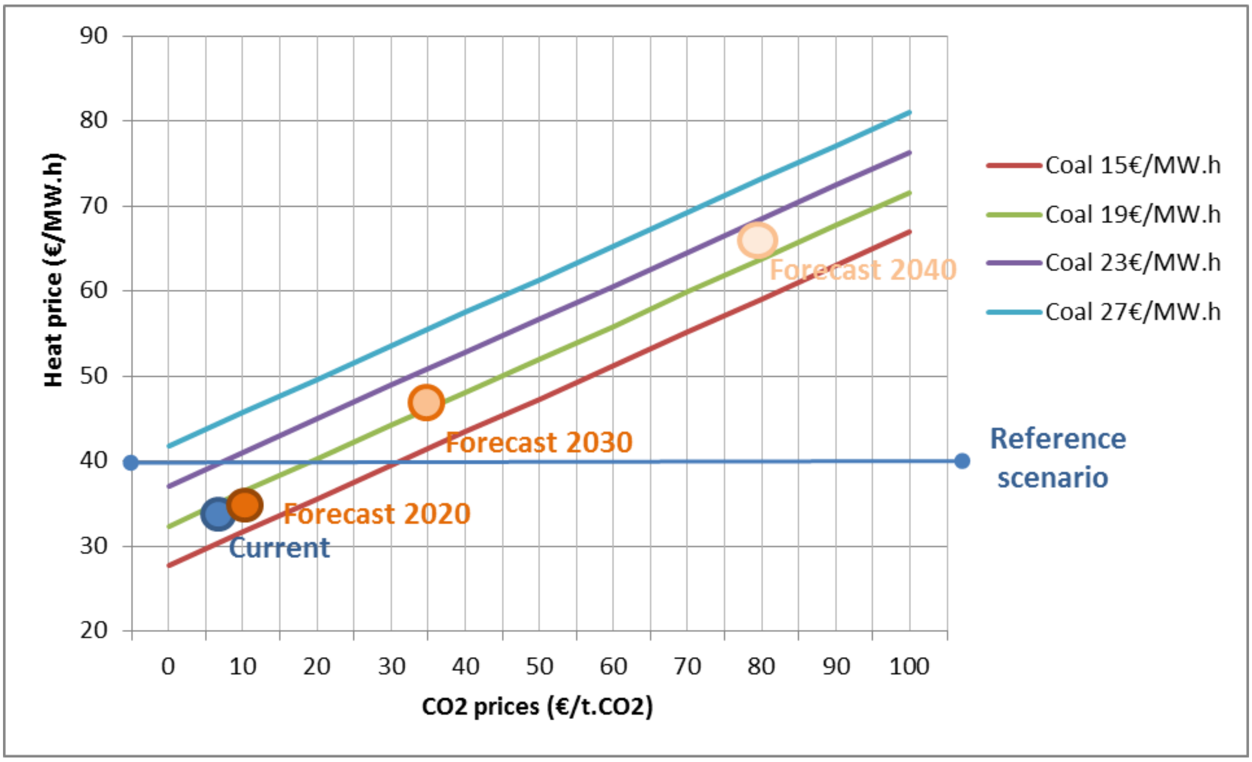


Figure 7 – Influence of coal and CO2 prices on the heat price

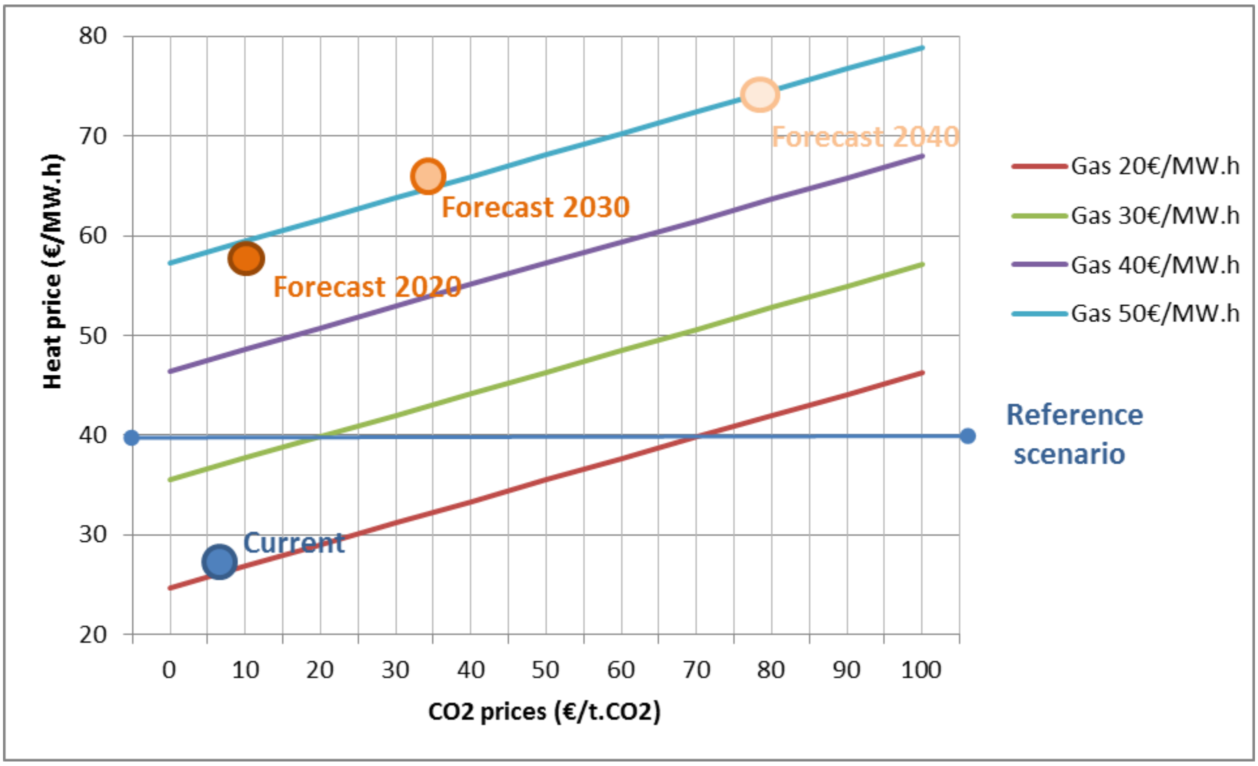


Figure 8 – Influence of gas and CO2 prices on the heat price

These calculations and graphs lead to the following conclusions:

- All the long-term scenarios based on EU forecast are higher than the reference scenario, based on a heat price of 40€/MW
- For Oil and Coal, CO_2 prices higher than 30 €/t ensure better case that the reference scenario, whatever are the fuel prices.
- For Gas, due to lower CO2 footprint, a slightly higher prices than current ones are expected to exceed the reference scenario. Current situation of low gas prices are mostly due to lower industrial activity and new gas sources (e.g. shale gas), and are not foreseen to stay at current low level in the next decade.

Indeed, it appears that:

- **An increase in energy prices favors heat against electricity, when comparing financial figures such as Net Present Values (NPV).**
- **The forecast for energy price increase gives a higher potential for heat than for electricity, mostly driven by fossil fuel costs and CO2 emissions costs.**
- **Based on the heat price analysis and EU forecasts, nuclear cogeneration based on HTR technology would bring significant value compared to fossil generation in the next decade. A large deployment of HTR plants would be profitable and fully justified from an industrial perspective. This confirms the need of a demonstration plant in the next 5 to 10 years to allow large deployment after 2030.**

3.2 Unit size and energy needs for industrial sites in Europe

3.2.1 Profile of industrial sites identified in Europe

Deliverable (NC2I-R - D4.21, 2015) identified more than 130 chemical sites in Central Europe. In order to identify precisely the energy needs for process heat and electricity, a questionnaire was developed, and communication engaged with end-users.

59 questionnaires were returned, providing information –partial or complete- on the energy needs of numerous end-users. Following the analysis, some aspects may limit the accuracy of the collected data, mostly because:

- Many chemical parks have no centralized energy solution, and each industry/company cares about its own energy demand. Energy supply could be optimized thanks to a centralized energy supply (as presented in deliverable (NC2I-R - D4.11, 2015), and then reach a bigger size, suitable for nuclear cogeneration.
- Energy consumption may vary along the year, with significant variation between summer and winter (mostly related to electricity needs), without identified common cause in this variation (energy requirement from the process, contractual dispositions, variation of the end-product demand…). Such variations might be a requirement for more variation capabilities in the supply (e.g. by switching production scheme between heat and electricity)
- Specific requirements (e.g. backup capacities, minimum load, reliability requirements...) were scarcely provided. This may have a significant influence on the energy production scheme.
- The survey was achieved on countries with very different energy policy regarding CO2 emissions, nuclear development, and cogeneration. Therefore, nuclear cogeneration initiatives and governmental support –which is of crucial importance-, may be very different, offering different opportunity for a demonstrator program.

An overview of the European sites, based on 55 questionnaires (some removed because of too specific conditions), gives the following breakdown:

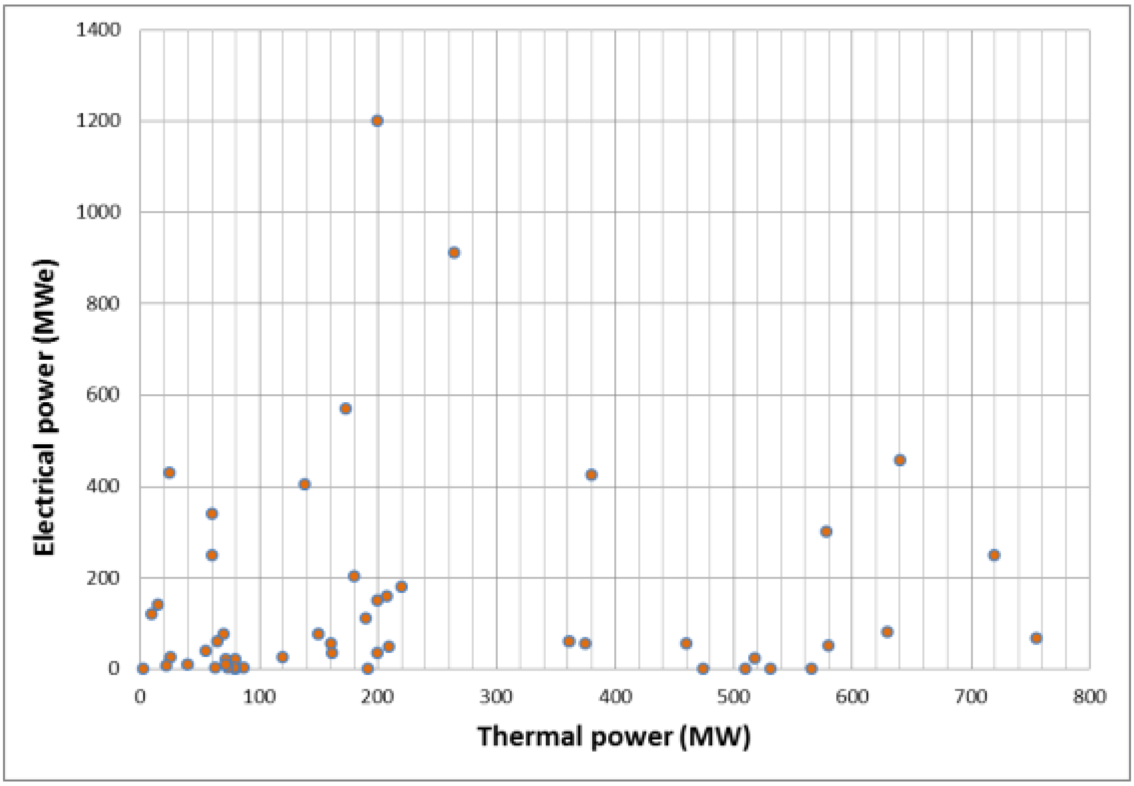


Figure 9 – Energy needs for European sites

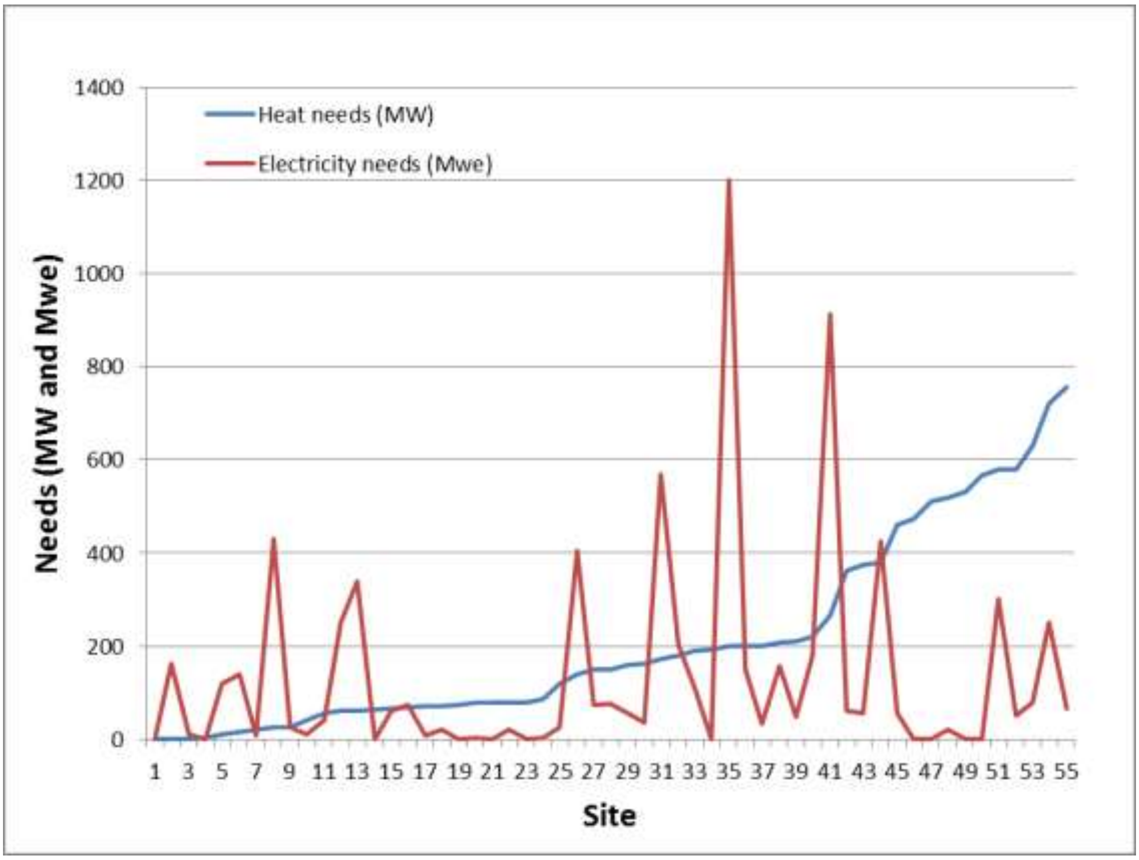


Figure 10 – Diagram ordered by heat needs

The representation in **Figure 9** and **Figure 10** shows that:

<u>Heat needs:</u>

- All sites except one have heat need lower than 750 MW
- 70% of the sites have a heat need lower than 250 MW (39 sites)
- 12% of the sites have a heat need between 250 and 500 MW (7 sites),
- 18% of the sites have a heat need higher than 500 MW (10 sites)

<u>Electricity needs:</u>

- 90% of the sites have an electrical need of less than 350 MWe
- 65% of the sites have an electrical need of less than 80 MWe

<u>Energy needs (Couple Heat/energy):</u>

- There is no obvious correlation between heat and electricity needs
- High heat consumers have relatively low electricity consumption

Neither the technical feasibility of nuclear cogeneration for every plant nor the conditions to develop a nuclear project in the vicinity of each site have been investigated for all sites. Only few cases were studied to evaluate the profitability of different end-users profiles (See §4. Simulation of the main parameters).

3.2.2 Plant size and economic aspects

The following section aims to determine a minimum thermal power level for an HTR plant, based on data from the reference scenario and other considerations related to plant size.

A conclusion from the previous chapter §3.1 Market conditions, revenues stream for nuclear cogeneration is the relative importance of Heat revenues in comparison to revenues from electricity generation. Therefore, it is assumed that the cogeneration plant will be sized to fulfill part or full heat needs. Electricity will be supplied either as by-product (valorization of heat loss in a steam-turbine cycle), or from the grid.

Although this is only a theoretical representation of the production, the contribution of Heat revenues to the NPV can be calculated independently from the contribution of electricity revenues.

Assumptions for the calculations are:

- Heat production from 50 to 450 MW (although 450 MW of heat production is unrealistic !) with different heat prices (covering assumptions of §3.1 Market conditions, revenues stream for nuclear cogeneration)
- Electricity production from 25 MWe to 200 MWe (the maximum production for a 2x250 MW unit, providing electricity only, with same operation conditions of a coal plant, is evaluated about 210 MWe)

The NPV of the project is the sum of both revenue streams. Potential other revenues (e.g. grid stabilization, reserves, shadowing capabilities…) are not taken into account.

The results are shown on the following figures:

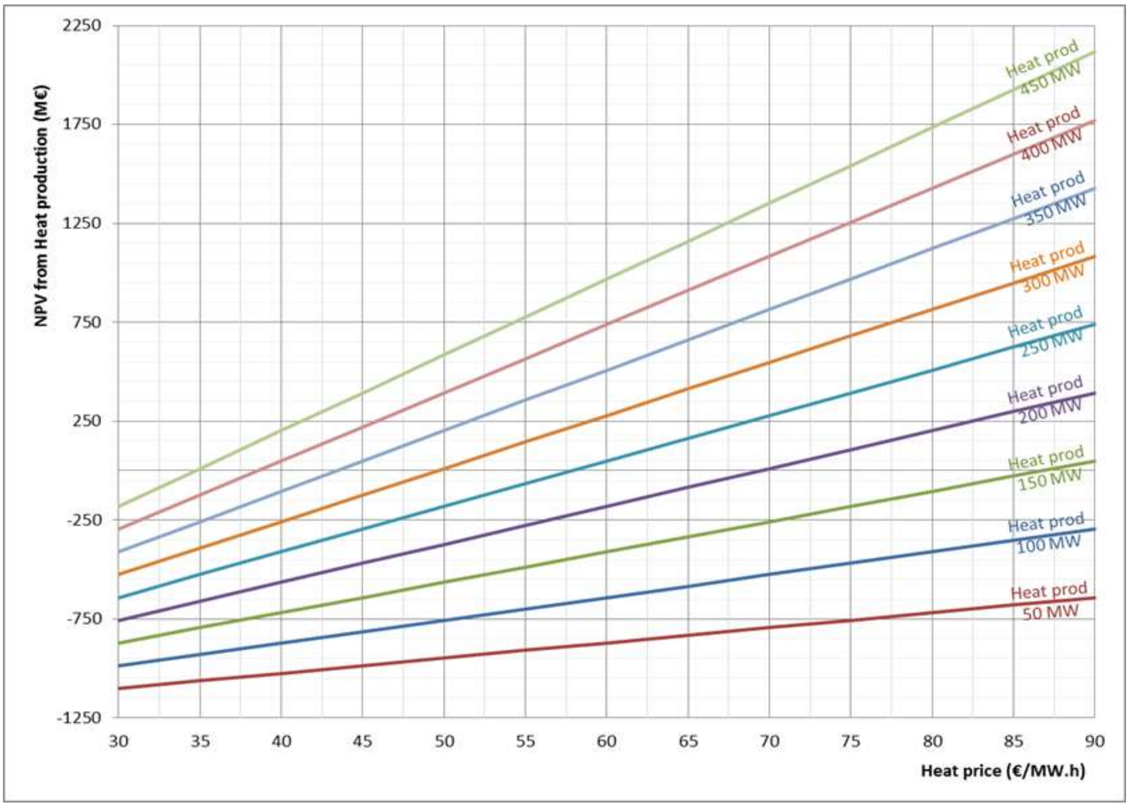


Figure 11 – Contribution of Heat revenues to the NPV

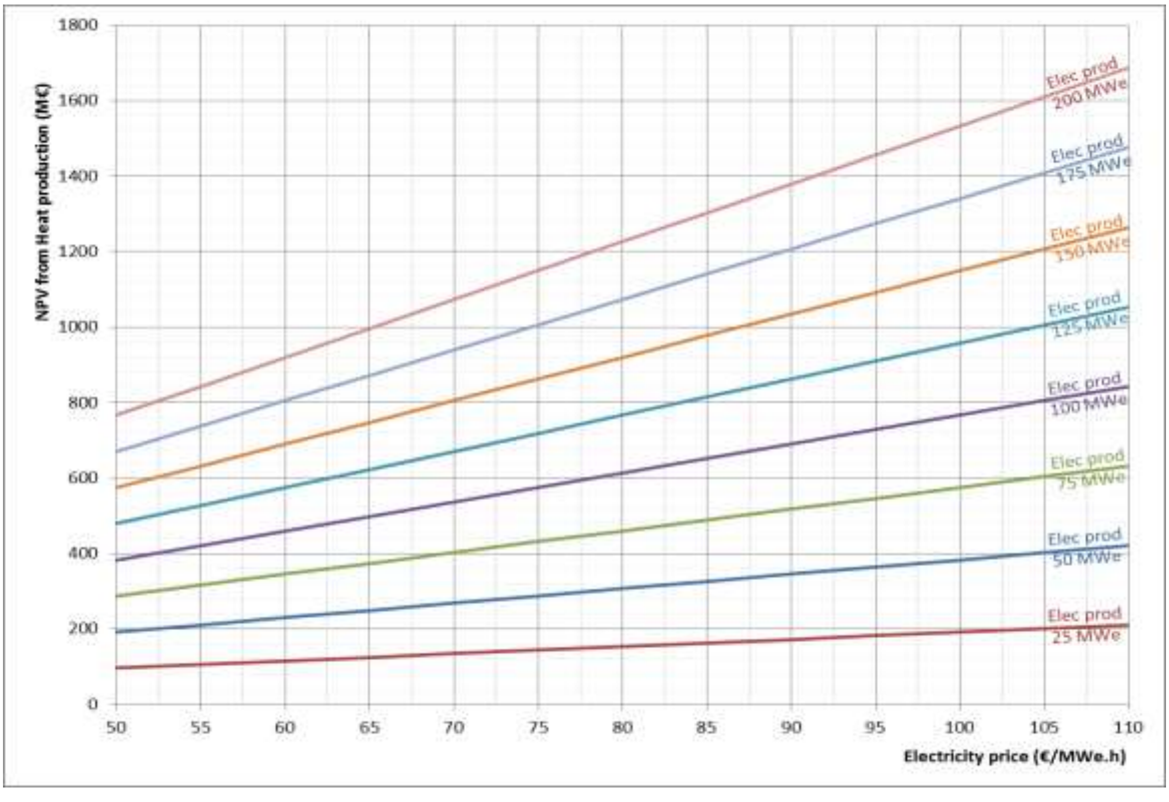


Figure 12 – Contribution of Electricity revenues to the NPV

Some theoretical configurations to reach a NPV=0 (which mean the threshold for project profitability) can be calculated and result in the following:

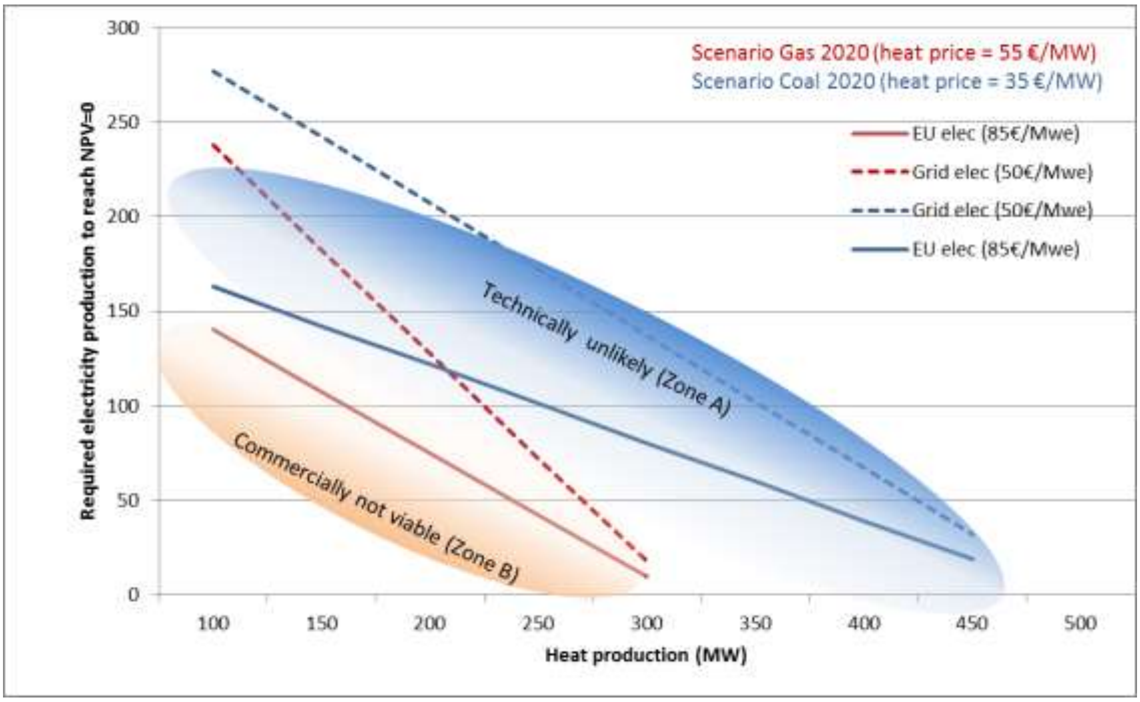


Figure 13 – Theoretical production scheme

Zone A:

As seen previously, the maximum electricity production for the HTR configuration used in the reference case, when all the heat is used in a steam turbine, is about 210 MWe. When heat is extracted for supplying a chemical process, electricity production will decrease significantly. Zone A represents such impossible configuration.

One can see that a low heat requirement from the end-user has to be compensated with a relatively high electricity need. If electricity is sold to the grid (50€/MWe), this can lead to unrealistic configurations (e.g. producing 150 MW of heat would require to produce about 200 MWe, which is very unlikely from a technical point of view)

Zone B:

Zone B represents low heat and electricity production, with a negative NPV meaning a project generating losses.

A preliminary assumption, with market conditions of the scenario “Gas 2020” show a commercially viable project when heat production alone is higher than 300 MW. Lower heat production requires additional revenues thanks to electricity production.

3.2.3 Evaluation of scale effect

In the past years of nuclear development, economy of scale was often mentioned as the main way to reduce the cost for nuclear energy. For High Temperature Reactors, past constructions have demonstrated the feasibility of diverse plants size, as shown in the following table:

	Dragon	Peach Bottom-1	AVR	FSV	THTR	HTTR	HTR-10	HTR-PM
Outlet Temp.	750	728	850/950	785	750	850/950	700 (900)	750
Size (MWth)	20	115	46	842	750	30	10	2x250
Size (MWe)	0	40	15	330	300	0	3	212

Table 2: Power level from previous HTR projects

In order to benefit from inherent safety features, the power output shall be limited in a range of 250 MWth to about 600 MWth, depending on the reactor design characteristics.

An inherently safe design does not require active safety systems in event of subsystem failure and is immune to major structural failure and operator error. It uses thermos-physical properties of materials and passive physical processes to achieve an optimum choice of reactor size, geometry and power density. It tolerates a total loss of coolant without any core meltdown risk.

This capability enables a simplified design and, consequently, competitiveness of modular HTR.

Indeed, smaller units may present interest by compensating effect of scale by “effect of number” as described in (OECD-NEA, 2011):

- Modularization: the NPP is conceived for the fabrication of separate modules. This fosters standardization and factory fabrication, and parallelization of activities is enabled. A smaller plant equipment size enhances the scope of modularization. A number of SMR units I backlog enable a mini-serial production. Expected benefits are higher quality and cost savings of shop-build as compared to stick-build.
- Learning effect: the higher the number of NPP built on the same site is, the higher the cost effectiveness of construction and assembling activities on site is, due to learning accumulation and best practice achievement by the manpower.
- Co-siting economies: economy of scale increases the unit cost of output product because it allocates the fixed costs on the first plant unit. Co-siting economies account for the redistribution of site-related fixed costs on the whole SMR fleet.
- Design savings: unique design and layout features are enabled by the smaller physical size of plant equipment. SMR design may result leaner and be simplified, with lower active components. On a standalone basis, the mere plant design should represent a cost-saving feature of SMR as compared to LR.
- Plant design: Simplify the design, less components, less systems, operate within current LWR & steam technology understanding, not at the edge, design plant for manufacture, not construction: whole plant and systems, not just the reactor vessels and components.

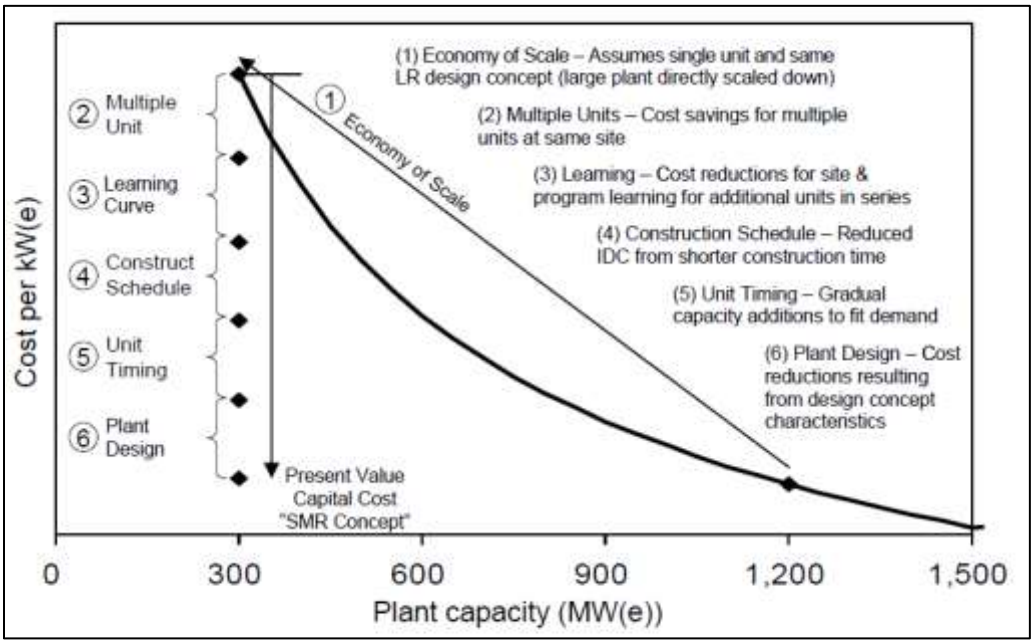


Figure 14 - Economy of numbers vs economy of scale

Applied to HTRs, a study compared different design size in the frame of the Chinese HTR project (INET , 2007), and concluded that a configuration with 1x458 MW was not presenting decisive advantages compared to one based on smaller units (2x250 MW).

Additionally, some benefits may be expected if specific needs (e.g. redundancy, continuity of production...) are expressed by the end-user.

On the other hand, the lower limit for the plant size is mostly driven by the economic profitability. The cost of smaller reactors and the influence of the main parameters driving the overnight costs of smaller reactors have been studied in several publications e.g. (IAEA-NP-T-3.7, 2013)

Although most of the studies and comparison are based on Light Water Reactors, similar factors are applicable to an HTR. A commonly agreed scaling law is:

$Cost(P1) = Cost(P0) \times (P1/P0)^n$ With: - P0, P1 power levels of the reference and project,
- n: scaling law parameter (n=0.4 to 0.6 for nuclear)

This leads to an exponential increase of cost when the power level decreases as presented in **Figure 15**

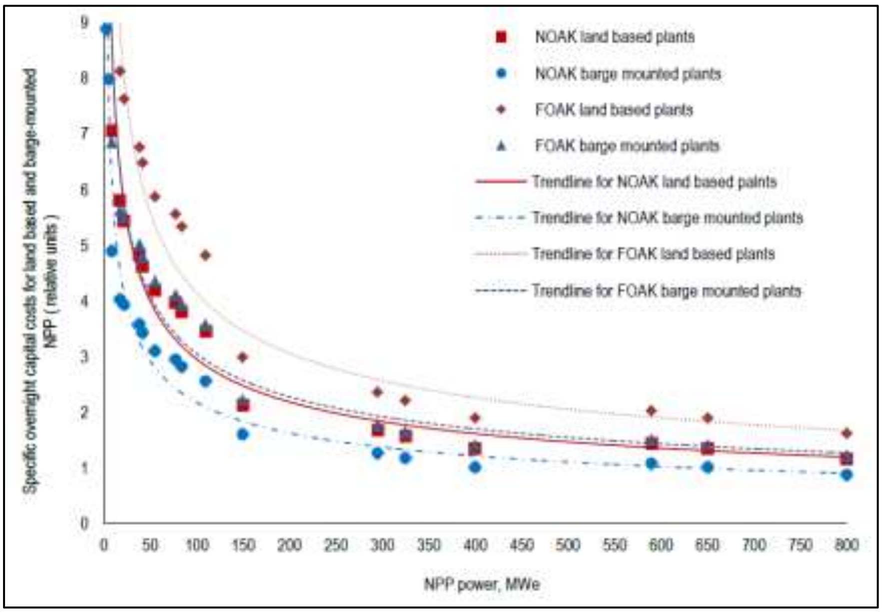


Figure 15 - Influence of the plant size on its cost

In fact, a preliminary evaluation of the variations for the main economic parameters (presented in (NC2I-R - D4.11, 2015) for smaller plants gives the following:

HTR Constructions costs: It is likely that construction costs for a smaller HTR will be higher than the reference used in (NC2I-R - D4.11, 2015), as the 2x250 MW HTR used as reference case already benefits from modular construction and simplified design by the use of safety features

Decommissioning costs: Decommissioning costs have a very low impact on the profitability of an HTR project, because the costs happen very late and therefore are heavily discounted. Moreover, no significant variation can be expected on the costs itself.

Fuel costs: Assuming same burnup and fuel management, no significant difference in fuel costs is expected. Moreover, fuel costs represent a limited fraction of the generation costs.

Lifetime: No significant difference in plant lifetime expected. Moreover, lifetime has a limited influence on the project, because the costs and revenues occurring after 40 years are heavily discounted in the NPV calculations.

Electricity price: Electricity price has a direct and immediate effect on the profitability of the plant.

Heat price: Heat price has a direct and immediate effect on the profitability of the plant.

Availability: Availability has a direct and immediate effect on the profitability of the plant. However, no major difference in availability is expected between plants of different size.

Tax rate: No difference in tax rate is expected between plants of different size.

Interest rate: Interest rate has a direct and immediate effect on the profitability of the plant. Although huge differences are not expected, smaller size may lead to lower interest rate thanks to lower risk of smaller projects, and lower financial needs.

O&M costs: O&M costs have a direct and immediate effect on the profitability of the plant. It is expected that smaller plant will have higher O&M costs (personnel costs might lead to increasing costs because of mandatory requirements currently in force, such as security personnel, operation personnel… Alternative such as fully automated operation are foreseen, but currently not accepted by regulators worldwide)

The following table summarizes the economic parameters and their influence on the profitability:

Economic parameter	Influence on profitability for smaller units
HTR Constructions costs	⬂
Decommissioning costs	⇨
Fuel costs	⇨
Lifetime	⇨
Electricity price	⇨
Heat price	⇨
Availability	⇨
Tax rate	⇨
Interest rate	⬀
O&M costs	⬂

Table 3: Variation of the profitability for smaller units

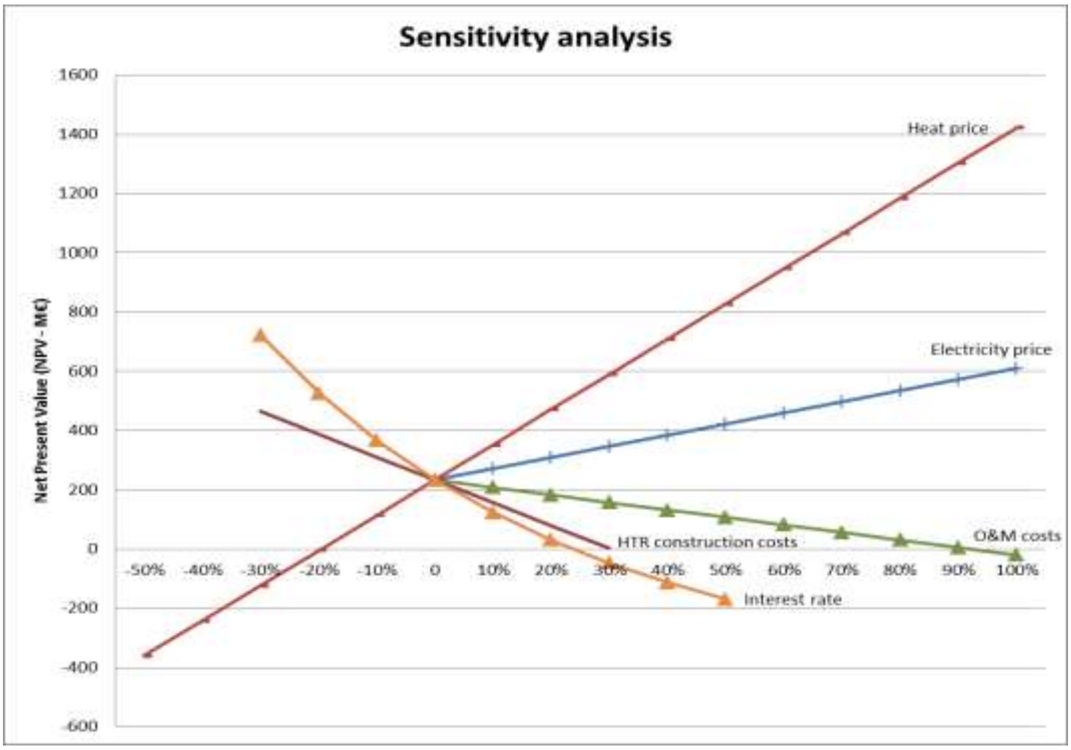


Figure 16 - Most influent parameters for different power level

Only heat and electricity prices are expected to increase the profitability. However, the interconnected grid in Europe offer limited possibilities for higher prices in electricity, and use heat in remote area, despite possible was not highlighted in the end-users requirements.

A dedicated study in §4 Simulation of the main parameters evaluates different configurations, based on real sites identified in deliverable (NC2I-R - D4.21, 2015) **to identify a minimum power level and an optimum Thermal to Electricity ratio.**

3.3 Industrial applications for cogeneration

The competitiveness of cogenerated industrial heat in HTR reactor has been estimated against the heat produced in gas, oil or coal-fired heat-only boilers. The cost of heat production in HTR cogeneration process has been calculated by valuing the simultaneous electricity production against the estimated wholesale electricity prices. Therefore the heat production costs have a strong dependence on prevailing wholesale market prices.

Based on the fuel price forecasts the heat provided by HTR could be competitive against the heat produced in coal and natural gas fired heat-only boilers around 2025.

Deliverables (NC2I-R - D4.11, 2015) and (NC2I-R - D4.31, 2015) analyze different applications suitable for HTR development and their potential for deployment in the next decades.

Expected mid to long-term solutions for the utilization of electricity and heat provided by HTR are:

- Industrial consumer with on-site CHP unit or need for one and sites with aging steam boilers. The main processes identified to be compatible with HTR were:
    - refinery distillation steam,
    - refinery distillation superheated steam,
    - petrochemicals - reaction enthalpy,
    - steam as utility for industrial complex,
    - paper steam (drying)
    - Carbon Capture and Storage

  Potential configuration and related economics are studied in §4 Simulation of the main parameters

- Coal-to-Liquid as conversion of bituminous or sub-bituminous coals to a liquid fuels like gasoline or diesel. Although this technology is generally more expensive than producing fuels from crude oil, it is potentially very attractive as the coal reserves are more than ten times more abundant, and are more evenly distributed than oil reserves. In addition, CTL enable higher energy independence for countries with large coal reserves.
  Potential configuration and related economics are studied in §5 A European HTR in support of a South African CTL Plant and §6 SYNKOPE: Synergetic coupling of energy sources for efficient processes

3.4 Grid stabilization aspects

Main economic drivers of the business model are presented in (NC2I-R - D4.11, 2015).

This sections aims to evaluate the benefit of energy storage for grid stabilization purposes under the form of chemicals or other cogeneration use.

As preamble, it is necessary to propose a representation of the HTR market, and identify the influences on the products and the revenues.

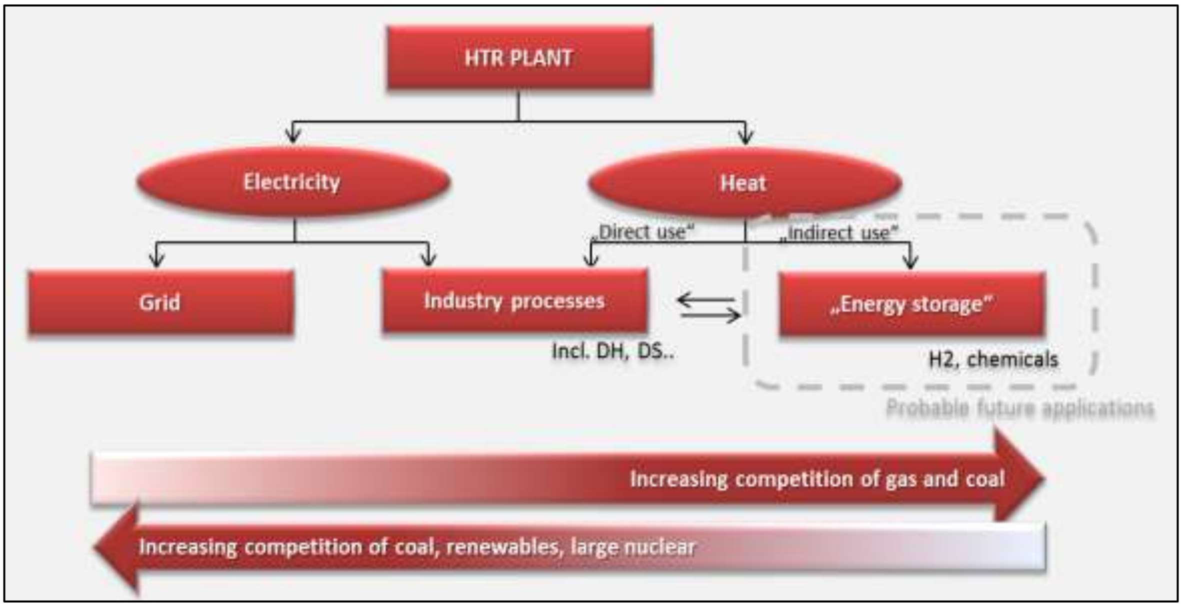


Figure 17 - Basic representation of an HTR market

As presented in **Figure 17**, an HTR (or more generally a cogeneration plant) can produce energy under different forms with different variability.

3.4.1 Electricity production and consumption

Solutions for energy storage are currently limited. Therefore, the network operator shall always ensure a balance between electricity production and electricity consumption.

- Electricity consumption depends of several factors such as human activity, transportation, season (if electrical heating is largely developed). Potential large variations with cycles (daily and yearly cycles) may be observed. The main possibilities to influence the electricity consumption are:
  - Contractual clauses with prices varying with the demand (with notice period for price changes between few hours and few days)
  - Intermittent consumers to “absorb” an excess of production (e.g. water storage, water splitting by electrolysis...)
  - Shadowing (planned or forced) of the customers

- Electricity production depends on the power at which the generation plant is operated. When the fossil-fuelled and nuclear plants have a high degree of predictability, wind-generated electricity may challenge the equilibrium.

In the last decades, balance between electricity production and electricity consumption was mostly adjusted by varying the production means with the highest variable cost, as presented in Figure 18.

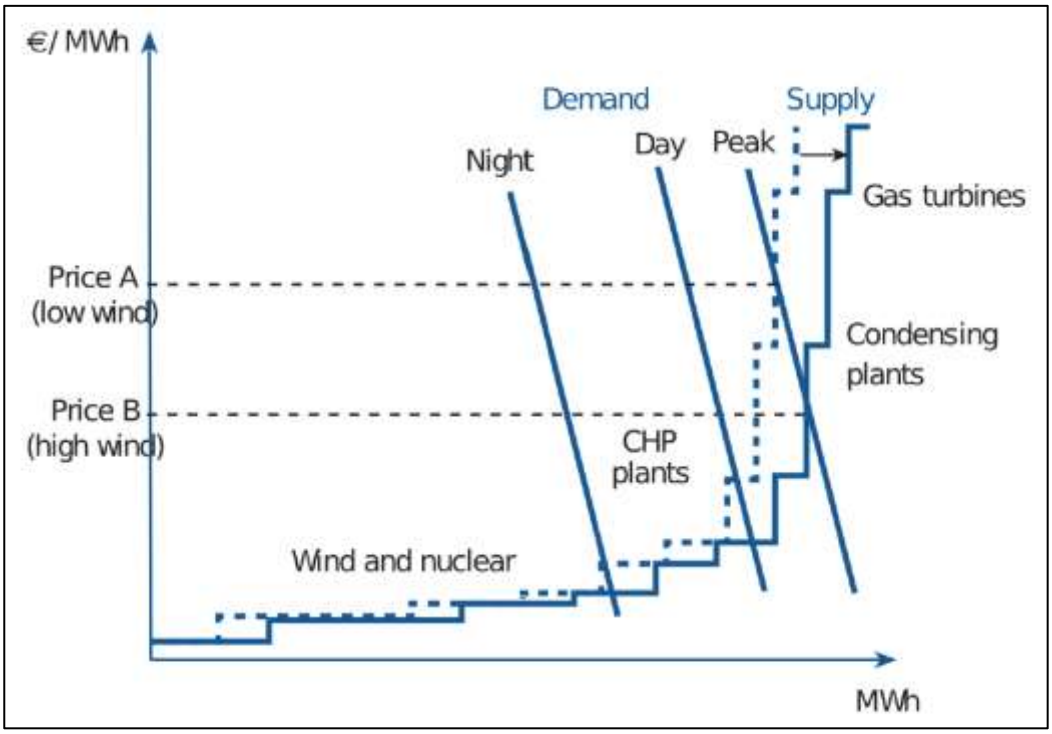


Figure 18 - Merit Order and pricing in a competitive electricity market at different wind levels

This growing share of renewables is likely to increase price volatility on the electricity market, and might impose other sources -as large nuclear power plants- to reduce their production for grid stability or feed-in priority purposes (as shown in **Figure 19**).

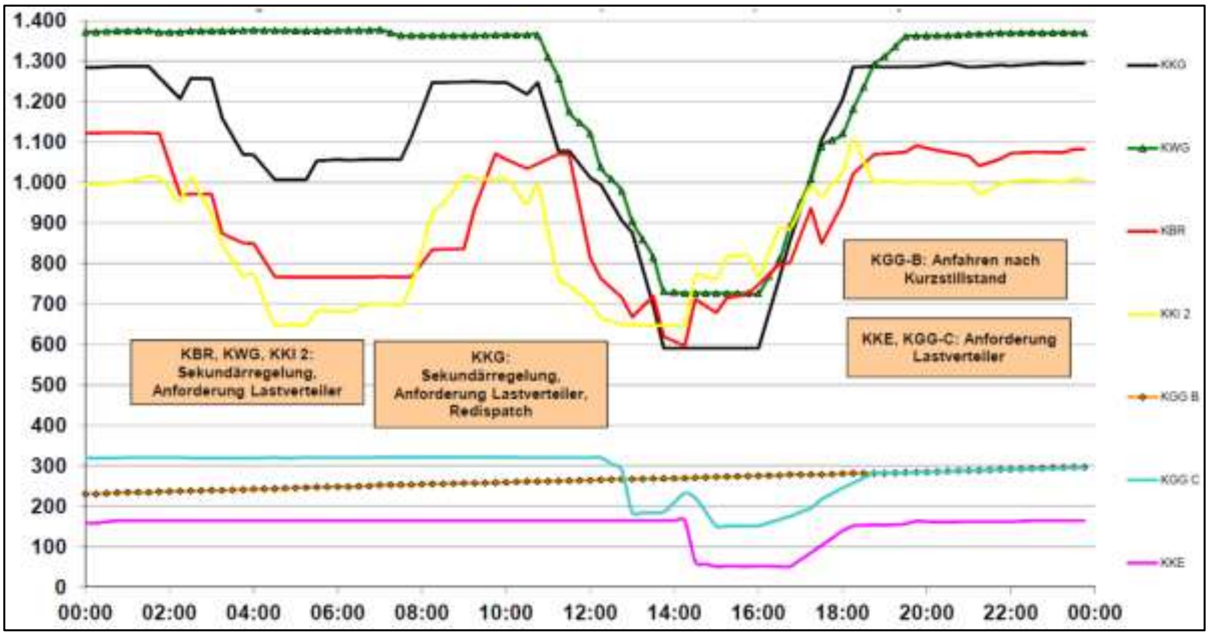
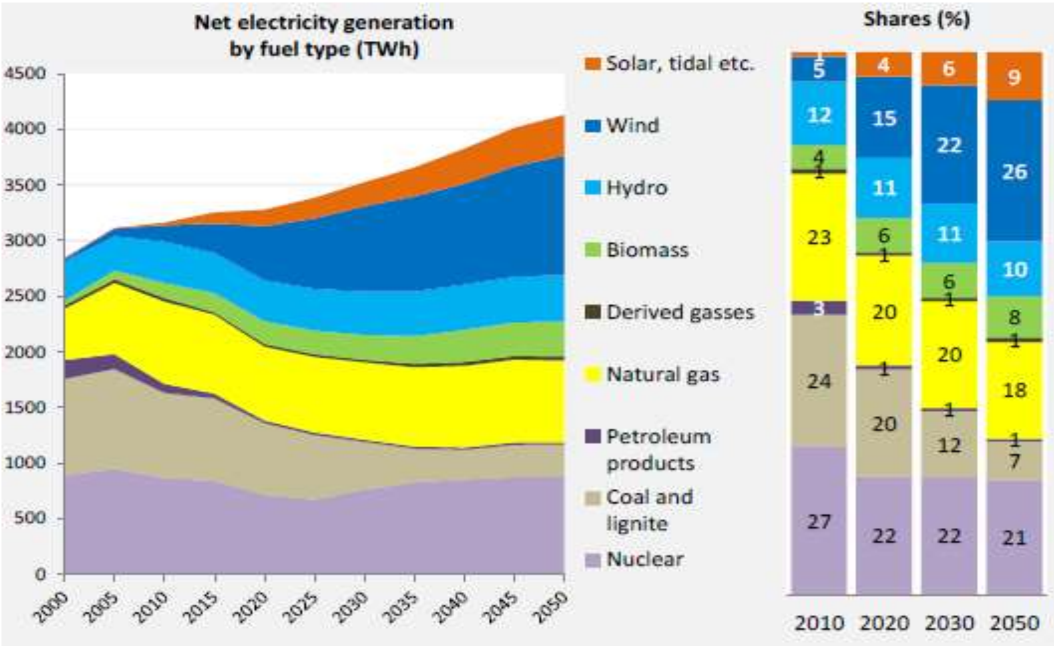


Figure 19 - Power control due to fluctuating wind and solar power (29/03/2013)

As consequence, availability factor of nuclear power plants might be affected. (OECD-NEA, 2011) about load-following aspects mentions that intermittent energy impacted the French nuclear fleet in an order of magnitude of 1,2% (as reminder, wind production was less than 5% in 2010, when it is expected to be several times higher within the next decade, according to **Figure 20**).



Source: EU energy, transport and GHG emissions – trends to 2050

Figure 20 - Electricity generation per fuel type

An HTR designed to produce an important share of electricity sold on the market would also suffer from reduced revenues:

- Reduced availability if the plant power level is decreased during period of low electricity demand. It is important to note that availability factor was identified as one of the most significant factor in the profitability of an HTR cogeneration project in NC2I-R deliverable (NC2I-R - D4.11, 2015). In addition thermal stress, inherent to load variations, would affect the expected lifetime of the plant.
- Reduced income if electricity is delivered to the grid whatever is the electricity price (also called “fatal production”). Such production regime shall however be agreed by the national grid operator, and therefore may challenge the authorization of the plant to be connected to the grid.

Additionally, regulations applicable for connecting generators to the grid (ENTSO-E, 2015) may – depending on the configuration of the power unit and agreement with the local Transmission System Operator- request load-following capabilities.

3.4.2 Impact of electricity prices volatility on economics of an HTR cogeneration plant

Figure 21 gives an overview of the repartition for electricity prices (hourly basis) on the main European competitive gross markets (Germany, Netherlands, France, Belgium, and Sweden) over the period 2009-2013.

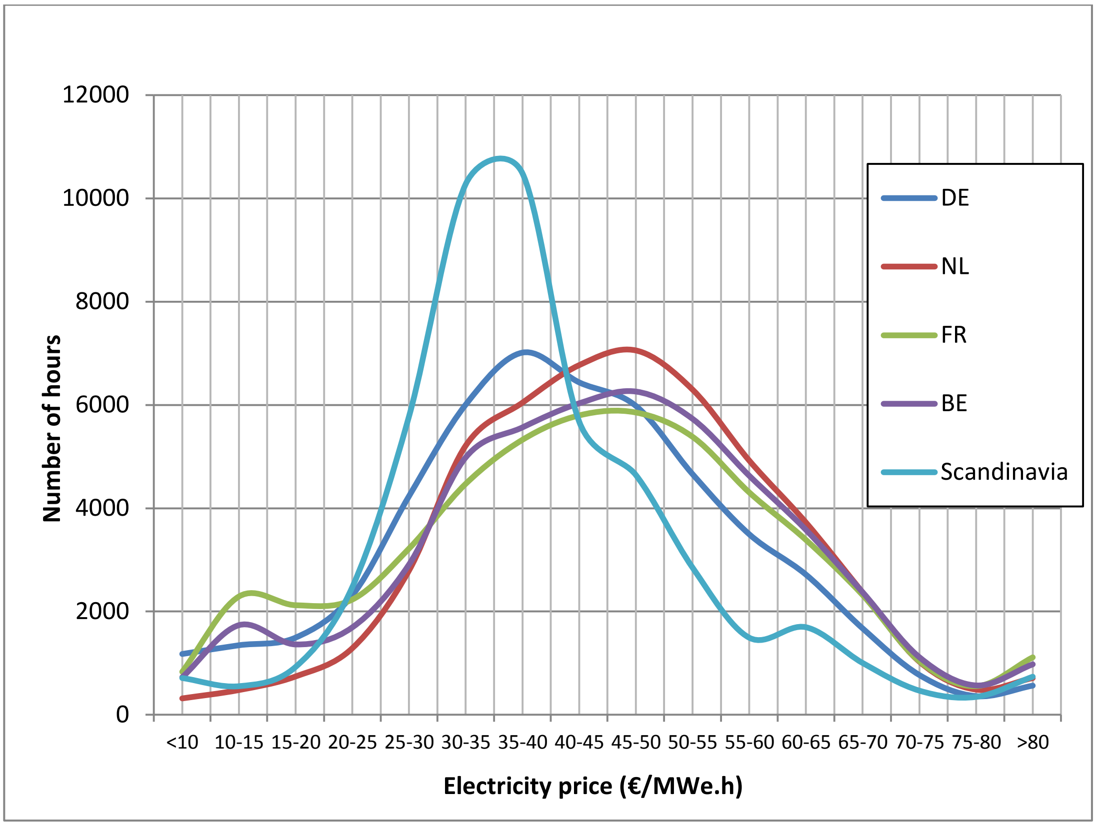


Figure 21 - Repartition of the electricity prices other the years 2009-2013
Source: Electricity price data EEX, APX, Powernext, Belpex, Nordpool-Elspot

Given the variations requested by the grid operator and the variations in electricity prices, Hybrid energy systems are considered in (NC2I-R - D4.31, 2015) as a potential for HTR deployment by improving he flexibility in the system, decrease the constraints in the grid and allow the operation of both renewable and nuclear power sources at levels that maximize economic benefit.

The benefit of a disposition to maintain full production by varying the ratio between heat used in a chemical process, and electricity production could therefore be studied in §**Error! Reference ource not found. Error! Reference source not found.**.

4 Simulation of the main parameters

This chapter is a contribution of BME to Deliverable D4.41

BME has undertaken a sub-task in WP4 as “Simulation of the main parameters for economical optimization”. This document contains the research results which satisfy the above mentioned sub-task.

4.1 Introduction to the coupled heat schema – economic analysis

The main objectives of this investigation aim at identifying the optimal ration between Thermal and Electrical production (T/E ratio) and reactor size for a HTR unit and evaluate the economics of selected sites (identified in the European Site Mapping task) with different configurations.

To reach these objectives, a coupled heat schema –economic model has been developed at the BME NTI. A 1D heat schema simulation program has been used to calculate the heat schema of the primary and secondary circuits of the HTR unit and the heat output circuits (which transport the process steam toward the industrial site) while the Net Present Value (NPV) was used to evaluate the economics of the same unit.

Based on the reference case for each site and concrete configuration, a parameter study has been carried out with 16 parameters (for e.g.: inflation rate, life time, availability of the HTR, price of released heat and electricity, etc.). Thus the comparison of the configurations for a given site or the different sites has become possible. Finally, the economics of two special cases of the HTR unit has been evaluated assisted by the coupled model.

4.2 The coupled heat scheme - economic model

In order to simulate the main parameters for economical optimization in case of a HTR unit operating in cogeneration run, BME NTI has developed a coupled heat scheme – economic model (its workflow can be seen in **Figure 22**). This model consists of a strong coupling between the heat schema and economic part which means that both model parts have an effect on the other.

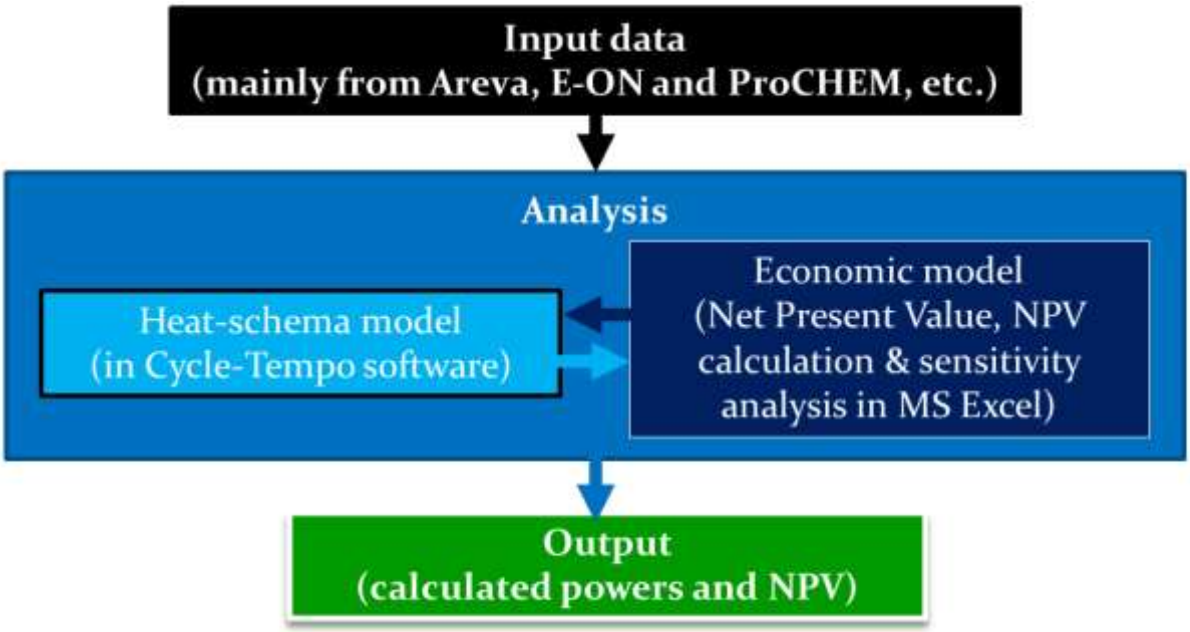


Figure 22 - The workflow of the coupled heat schema – economic calculations

4.2.1 Input data to the coupled model

Four different sites were investigated by the coupled model. The first is the so-called NC2I-R reference site (NC2I-R - D4.11, 2015). This is the only case where the heat schema data was not calculated by BME assisted by the Cycle-Tempo. The input data of the NC2I-R reference site is based on a Siemens KWU (nowadays AREVA GmbH) project for the chemical industry in the mid 80’. Technical data are provided in the reference (AREVA GmbH, 2014), and was the basis for other studies within NC2I-R project, such as the economic assessment study (NC2I-R - D4.11, 2015).

The second site is the Chemelot site (EUROPAIRS - D2.1, 2011), which is in the Netherlands. This case was used to investigate the effect of HTR size on the economics. The medium sized third and the small sized fourth sites have been identified by the European site mapping task (Task 4.2) performed within the framework of the project (NC2I-R - D4.21, 2015). They are in Poland, at Gdansk (medium size) and Trzebinia (small size).

These two Polish sites were used to investigate the economics of different sized but real sites.

Most of the input data and main assumptions of this study are based on data provided by Areva GmbH (AREVA GmbH, 2014) .A reference case and a parameter study has been described in detail in the document of D4.11 (NC2I-R - D4.11, 2015) (which investigates the effect of the variations in the main input parameters on the NPV).

That is the reason why a detailed description of the input data, calculation method and main assumption are not given here. A summary of the reference case and variations applied in the input data can be seen in **Table 4**. The data of reference case were used to this study as well, but the range of the variations was extended which can be seen in **Table 5**.

Item	Reference case	Variation min	Variation max	Min value	Max Value
HTR construction costs in year 0 **(Nominal capacity)** **(Released thermal power)** **(Released electrical power)**	930.8 M€ (2x250 MW) (387.63) (98.25)	- 30%	+ 30%	651.6	1210.0
O&M costs in year 0	23.4 M€/year	0	+ 100%	23.4	46.8
Decommissioning costs in year 0	115 M€	0	+ 200 %	115	345
Fuel costs in year 0	27.1 M€/year	- 30%	+ 100%	19.0	54.2
Lifetime	40 years	- 30%	+ 30%	28	52
Electricity price in year 0 **(Electricity price increment)**	50 €/MW_e (2%/year)	0	+ 100%	50	100
Steam price (incl. CO2) in year 0 **(Heat price increment)**	40 €/MW_{th} (2%/year)	- 50%	+ 100%	20	80
HTR Availability	85%	- 20%	+ 10%	0.68	0.94
Construction time	4 years	0	+ 50%	4	6
Delay during commissioning	0 year	0	+ 2	0	2
Tax rate	20%	- 10%	+ 40%	18	28
Interest rate **(Inflation rate)** **(Alternative cost of capital)**	8% (2%) (6%)	-30%	+ 50%	5.6	12
Design and licensing duration	0 year	0	+ 2	0	2
Design and licensing cost	0 M€	0	+ 300	0	300

Table 4: The main input data and variations of the parameters in the NC2I-R reference case (AREVA GmbH, 2014) (NC2I-R - D4.11, 2015)

Some deviations from the reference case were needed in the set of input data in case of the Chemelot, Gdansk and Trzebinia sites. These deviations will be defined in the next paragraphs.

Item	Reference case	Variation min	Variation max	Min value	Max Value
HTR construction costs in year 0	930.8 M€	-40%	+50%	558.48	1396.2
(Nominal capacity)	(2x250 MW)	(-80%)	(+300)	(2x50)	(2x750)
(Released thermal power)	(387.63)	(-97.5%)	(-22.3%)	(10)	(300)
(Released electrical power)	(98.25)	(-99.6%)	(+338%)	(0.434)	(430.8)
O&M costs in year 0	23.4 M€/year	-40%	+140%	14.04	56.16
Decommissioning costs in year 0	115 M€	-25%	+200%	86.25	345
Fuel costs in year 0	27.1 M€/year	-40%	+140%	16.26	65.04
Lifetime	40 years	-40%	+50%	24	60
Electricity price in year 0	50 €/MW_e	-40%	+140%	30	120
(Electricity price increment)	(2%/year)	(-50%)	(+40%)	(1%)	(2.8%)
Steam price (incl. CO2) in year 0	40 €/MW_{th}	-40%	+140%	24	96
(Heat price increment)	(2%/year)	(-50%)	(+40%)	(1%)	(2.8%)
HTR Availability	85 %	-30%	+15%	59.5%	97.75%
Construction time	4 years	-50%	+100%	2	8
Delay during commissioning	0 years	-0%	+0%	0	0
Tax rate	20%	-40%	+140%	12%	48%
Interest rate	8%	-45%	+90%	4.4%	15.2%
(Inflation rate)	(2%)	(-60%)	(+120%)	(0.8%)	(4.4%)
(Alternative cost of capital)	(6%)	(-60%)	(+120%)	(2.4%)	(13.2%)
Design and licensing duration	0 years	-0%	+0%	0	0
Design and licensing cost	0 M€	-0%	+0%	0	0

Table 5: The extended range of variations for parameters

4.2.2 The coupled model and its output

As it can be seen in **Figure 22**, the coupled model consists of two sub-models. First a heat schema model was developed which represents the primary, secondary and process steam circuits of the HTR unit (see **Figure 23** and **Figure 24**).

In **Figure 23**, the red rectangles indicate the primary circuits of the two HTR (nominal capacity 500 MW each which was modelled as a 500 MW heat source in the CT) while the green rectangle frames the main live steam branch (mass flow rate is 480 kg/s, live steam parameters are: 169 bar, 570°C) which collects the live steam from the two helium-water steam generators.

This live steam goes to a Siemens high pressure turbine. One of the first taps provides steam with high state variables (140 bar and 336°C) to the first heat output circuit (framed by red rectangle in **Figure 24**). The live steam expands in the high pressure turbine then goes through a reheating heat exchanger. The reheated steam goes into a Siemens low pressure turbine. Two taps of this turbine provide further steam to the second and third heat output circuits. The second heat output circuit (framed by blue rectangle in **Figure 24**) needs steam with intermediate state variables (45 bar and 257°C) while the third (framed by green rectangle in **Figure 24**) needs steam with relatively low pressure and temperature (18 bar and 207°C).

During the CT modelling a heat source based modelling has been applied. Furthermore, it is worth to mention that the three heat output circuits are stand-alone circuits which connect to the secondary loops of the HTRs with heat exchangers. It is an important fact for safety of the HTRs.

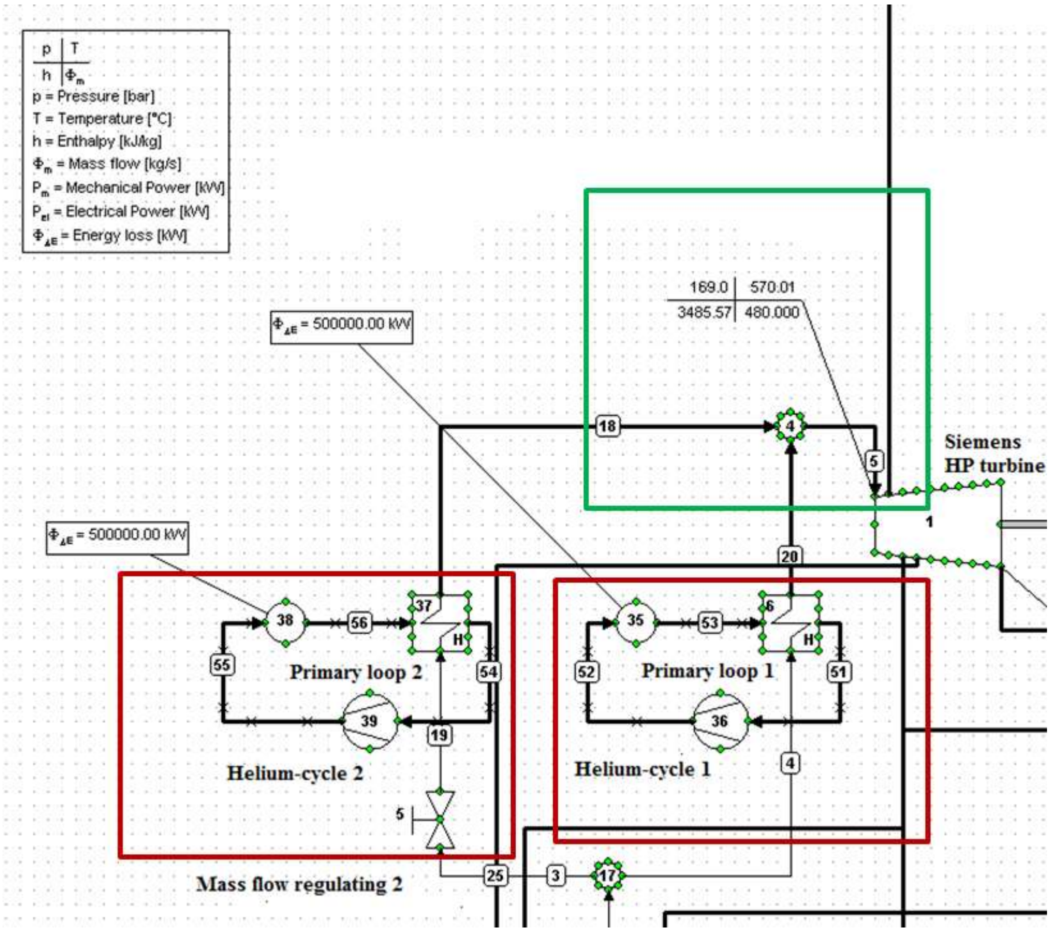


Figure 23: The primary circuit of a 2x500 MW twin HTR unit (marked by red rectangle) which provide process steam and electricity for the Chemelot site (EUROPAIRS - D2.1, 2011)

One can design, analyse, optimize and monitor the thermodynamics of an energy system in Cycle-Tempo (CT) (The ASIMPTOT homepage, 2015). CT enables full-featured “exergy” analysis for the correct optimization of the design and operation of a concrete system. There is a possibility of real-time integration with existing plant-wide data monitoring systems for performance analysis and trouble-shooting by CT (The ASIMPTOT homepage, 2015). The simulation of a concrete system works in 1D based on energy and continuity equations solved in the CT (The ASIMPTOT homepage, 2015)].

The BME NTI had total freedom in the design phase of primary and secondary circuits but where it was possible the previous plans (NC2I-R - D4.11, 2015), (EUROPAIRS - D2.1, 2011), (AREVA GmbH, 2014) have been taken into consideration. So, only the gaps between previous plans were filled by the own experience and expertise of BME NTI in the CT model. If more complete and precise plans of primary and secondary circuits will be available then the CT modelling could be updated and recalculated.

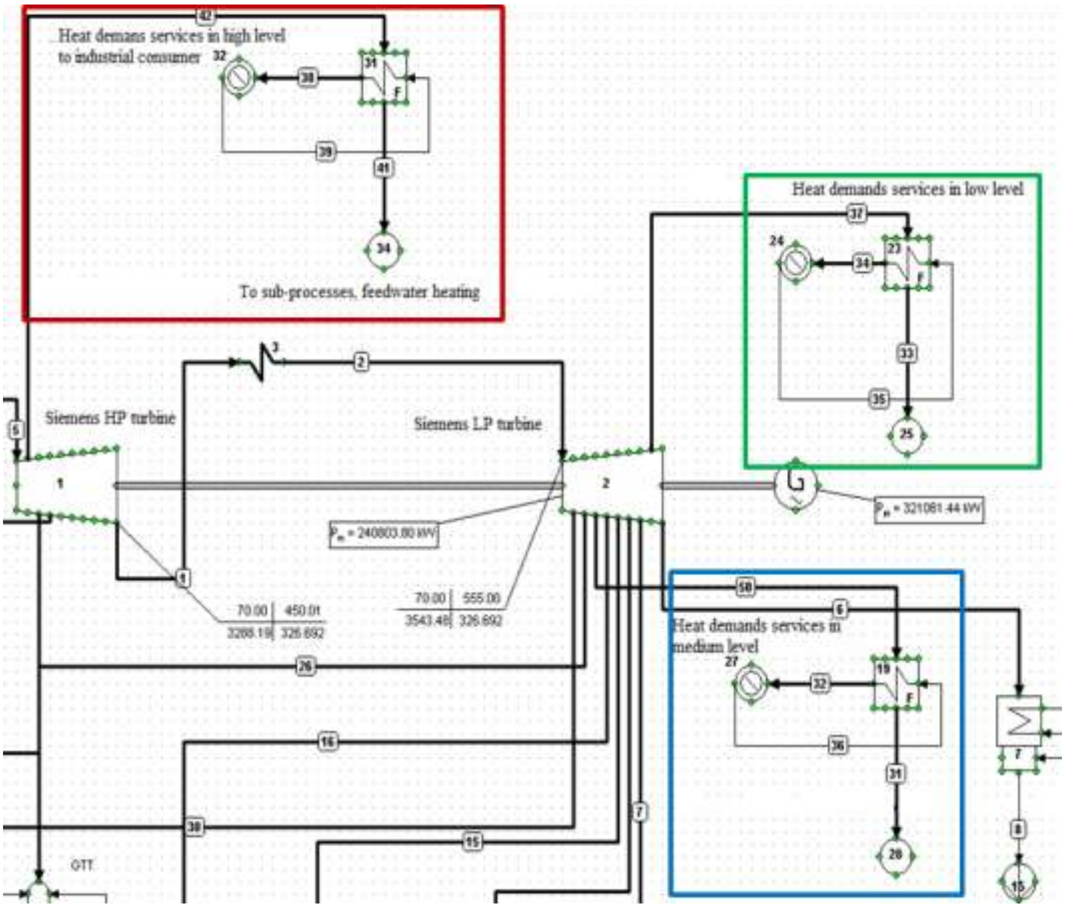


Figure 24: The secondary circuit of a 2x500 MW twin HTR unit and the three heat output circuits (marked by red, green and blue rectangles) for the Chemelot site [2]

This heat schema model was built in the Cycle-Tempo software (The ASIMPTOT homepage, 2015) (see a screen shot about the GUI of Cycle-Tempo in **Figure 25**).

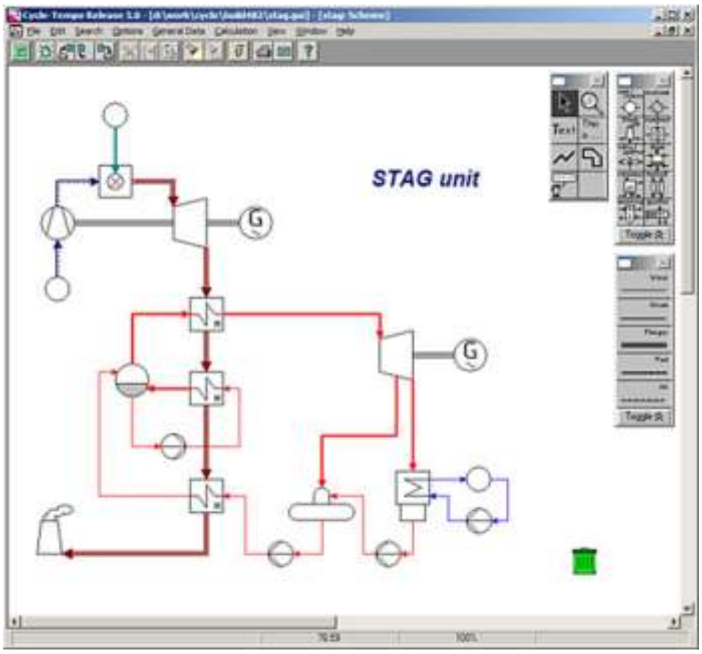


Figure 25: The general user interface of Cycle-Tempo software (The ASIMPTOT homepage, 2015)

The following simplifying assumptions were applied at the heat schema model:

- Concentrated losses (consolidated losses in turbines),
- Fixed parameters (e.g.: live steam pressure and temperature, levels of heat output circuits pressure, equipment efficiency),
- The model was made for nominal operating conditions (design mode) due to lack of data on other type of operating conditions (for e.g. off-design conditions).

The following input data are required for CT simulation:

- the number and type of reactors (the heat source(s)),
- the schema of primary and secondary circuits if available,
- the number and required parameters of heat output circuits,
- etc.

The calculation with this heat schema model provides the following results for a given twin HTR unit configuration[1]:

- the released thermal (MWth) and electrical power (MWe),
- the mass flow rate (kg/s), temperature (°C) and pressure (bar) of the live steam,
- the temperature (°C) and pressure (bar) of the coolant in the reheater and condenser,
- the temperature (°C) and pressure (bar) of the fluid in the low, intermediate and high pressure heat output circuits,
- etc.

In the second step, an economic model (NC2I-R - D4.11, 2015) was applied to calculate the Net Present Value (NPV) of the supposed investment into a HTR unit operating in cogeneration run. The previously calculated released thermal and electrical powers were used (next to many others see in **Table 4** and **Table 5**) as input parameters in the economic calculations. The verification of the economic model used for this study has been performed in collaboration with two partners: the E-ON and NWU (see its results later). The calculation with the economic model provides the following results:

- the NPV for the reference case,
- the parameter study on the NPV defined by the variations showed in **Table 4** and **Table 5**,
- the overview figure about the NPV versus the variations (see for e.g. **Figure 26**).

4.2.3 The verification of the applied economic model

To ensure good agreement in results got with the same input parameters, verification calculation has been performed between the economic model of three participating partners of the project (E-ON, NWU and BME). For this purpose, the reference case showed in **Table 4** was used. The resulting NPV values were very close to each other (see **Table 6**).

Partner	NPV [M€]	Discrepancy from E-ON result [%]
E-ON	**233**	**0%**
NWU	**231**	**0.86%**
BME	**230.94**	**0.88%**

Table 6: The result of the verification

[1] The listed results depend on many parameters, for e.g. the nominal capacity of the twin HTR unit (see its variation in **Table 4** and **Table 5**).

Difference between models is caused by rounding of intermediate calculation. Response to different input data shows a similar behaviour of the models. Therefore output results from the 3 models are consistent for comparison.

The overview figure about the sensitivity analysis of BME can be seen in **Figure 26**. As it can be seen, the sensitivity of 16 parameters (see in **Table 4** and **Figure 26**) was investigated in the predefined variation ranges (see in **Table 5**). Each curve represents different cases corresponding to the variation of its parameter. Only one parameter was changed at each curve. The horizontal axis represents the variation in % while the vertical axis represents the NPV in M€ of a given case. All curves go through the point representing the reference case (0% and 230.94 M€). The NPV of the reference case shows a positive value and it is 230.94 M€. It means that the project would increase the shareholder value and therefore should be carried out. This statement is only valid under the above given assumptions and input variables. Therefore a deeper analysis of the sensitivity of the NPV to changes in the input variables is necessary and has been carried out (see **Figure 26**).

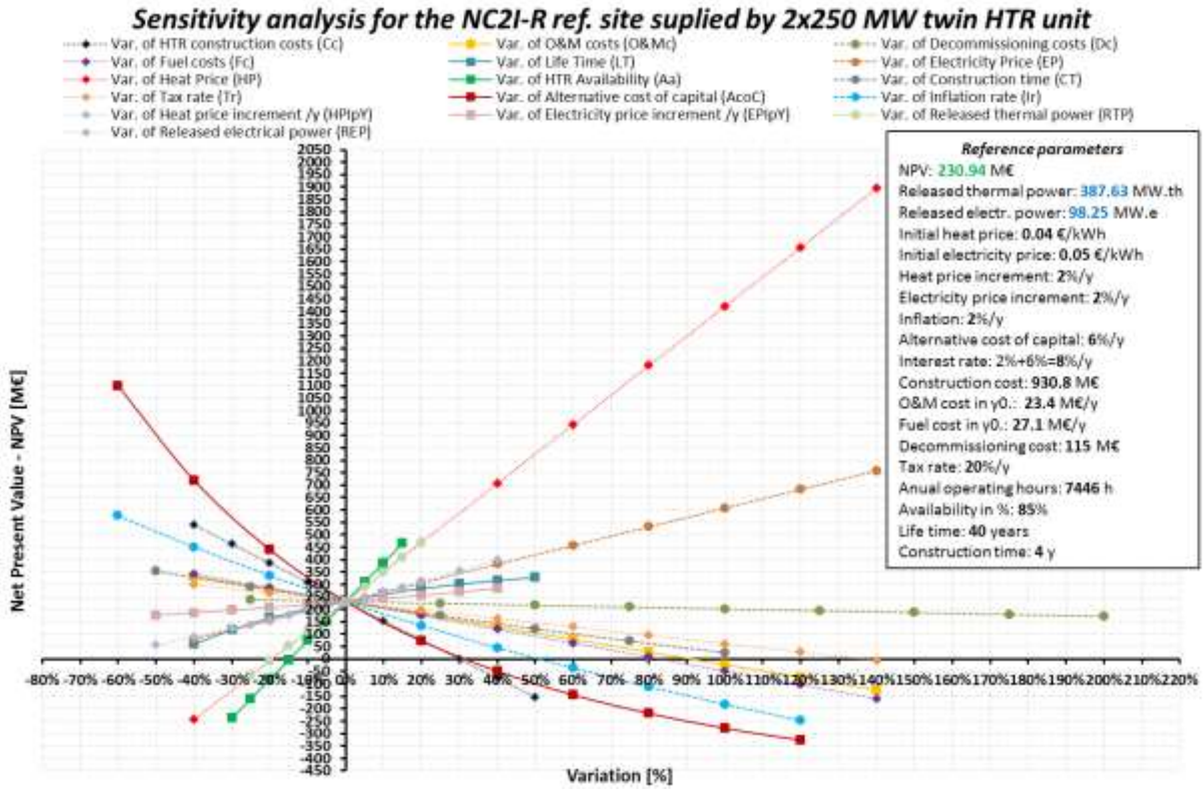


Figure 26: The overview figure about the results of BME economic model verified to the economic model of NWU and E-ON [1]

The costs, interest-, inflation- and alternative cost of capital rates and tax rate have a negative effect on the NPV. An increase in one of the above mentioned variables leads to a decrease of the NPV. A variation of the decommissioning costs has almost no effect on the NPV (see the almost horizontal green curve in **Figure 26**) due to its location at the end of the overall life-cycle of the twin unit, whereas a relative change of the inflation or alternative cost of capital rate have a very significant effect on the NPV (see the corresponding curve in **Figure 26**). This behaviour can be explained by the low costs of decommissioning for each MWh of generated energy and by the important role that the interest rate plays for discounting all cash flows when calculating the NPV. These findings coincide with the outcome of the economic assessment study (NC2I-R - D4.11, 2015).

The lifetime, the availability and the energy prices (for heat or electricity) show the opposite, a positive effect on the NPV (see in **Figure 26**). An increase in one of these variables causes an increase of the NPV. Close to the values of the reference case, a variation of the lifetime has the least impact on the NPV, while a variation of the availability has the largest effect on the NPV (see in **Figure 26**). A change of few percent of the availability from the initial assumption (85%) represents a significant change in absolute terms and, hence, has an immense impact on the NPV (NC2I-R - D4.11, 2015).

In order to assure a positive NPV, all parameters that cannot be influenced by the plant operator (such as the market price of electricity and heat or the tax rate) should be carefully watched and eventually the respective risks should be hedged (e.g. thanks to Long-term Power Purchase Agreement) (NC2I-R - D4.11, 2015). Furthermore, the plant operator should try to influence the other parameters (such as availability, efficiency or construction time) to increase the NPV, e.g. by altering some details in the plant design. A technical and economic study shall evaluate if the costs of modifications lead to a sufficient increase of the NPV (NC2I-R - D4.11, 2015).

With the assumptions of the reference scenario or case, Internal Rate of Return (IRR) was calculated and it is around 9.9% (NC2I-R - D4.11, 2015). When all power is converted to electricity under the conditions of a coal plant, the Levelized Cost of Energy is 81.6 €/MWe. Therefore, under the assumptions of the reference scenario, a HTR heat source, used for electricity generation only, would hardly compete with current fossil or large nuclear generation conditions (NC2I-R - D4.11, 2015). When all power is converted to heat, the Levelized Cost of Energy is calculated 34.7 €/MWth. Therefore, under the assumptions of the reference scenario, a HTR heat source could compete with gas fired power plants under current conditions. Coal remains a cheaper option, as long as CO_2 price remains low (NC2I-R - D4.11, 2015).

4.3 The effect of HTR size on the T/E ratio and the economics

In order to determine the optimal size (nominal capacity) of the twin HTR unit (if exists at all), the previously described coupled model has been applied for a case study. Two aspects were investigated: the effect of HTR size on the thermal versus the electrical (T/E) ratio and the economics (NPV).

The selected site for this case study is the Chemelot site (EUROPAIRS - D2.1, 2011). It is a chemical complex in the Netherlands and consists of 50 different chemical units. The current energy demands are satisfied by natural gas-based cogeneration which provides 180 MWe electrical and 220 MWth thermal powers (as process steam through two heat output circuits with different levels of temperature and pressure).

Two different cases were studied:

- **Case 1**: when the maximal thermal power is constant (300 MW_{th}), which is more realistic than Case 2,
- **Case 2**: when the electrical power demand is constant (144 MW_e).

The nominal capacity was handled as a parameter and has been changed in both Cases 1 and 2 with the following values (in MW):

- 2x200,
- 2x250 (Reference case for the economics),
- 2x300,
- 2x400,
- 2x500 (Reference case for the T/E ratio),
- 2x750.

4.3.1 The effect of HTR size on the T/E ratio

Table 7 and **Figure 27** show the results of CT simulations for Case 1. As it can be seen, the released electrical power increases monotonically while the released thermal power reaches its maximum value (300 MWth) at the configuration of 2x400 MW. This 300 MWth satisfies the process heat demand of the Chemelot site and the supposed district heat demand of the neighbourhood of the site.

	Heat Source (MW)					
Parameters / Configuration	2x200	2x250	2x300	2x400	**2x500**	2x750
Mass flow (kg/s)	192	240	288	384	**480**	720
Released electrical energy (MW_e)	91.63	96.4	109.5	146.1	**227.4**	430.8
Live steam pressure (bar)	169	169	169	169	**169**	169
Live steam temperature (°C)	570	570	570	570	**570**	570
HP heat output circuit pressure (bar)	140	140	140	140	**140**	140
HP heat output circuit temperature (°C)	336.6	336.6	336.6	336.6	**336.6**	336.6
MP heat output circuit pressure (bar)	45	45	45	45	**45**	45
MP heat output circuit temperature (°C)	257.44	257.44	257.44	257.44	**257.44**	257.44
LP heat output circuit pressure (bar)	18	18	18	18	**18**	18
LP heat output circuit temperature (°C)	207.12	207.12	207.12	207.12	**207.12**	207.12
Released P_{th} in the 1st circuit (MW_{th})	30	50	100	150	**150**	150
Released P_{th} in the 2nd circuit (MW_{th})	50	50	50	100	**100**	100
Released P_{th} in the 3rd circuit (MW_{th})	30	50	50	50	**50**	50
Released thermal power (MW_{th})	110	150	200	300	**300**	300

Table 7: The simulation results of CT for Case 1 (reference case marked by bold text)

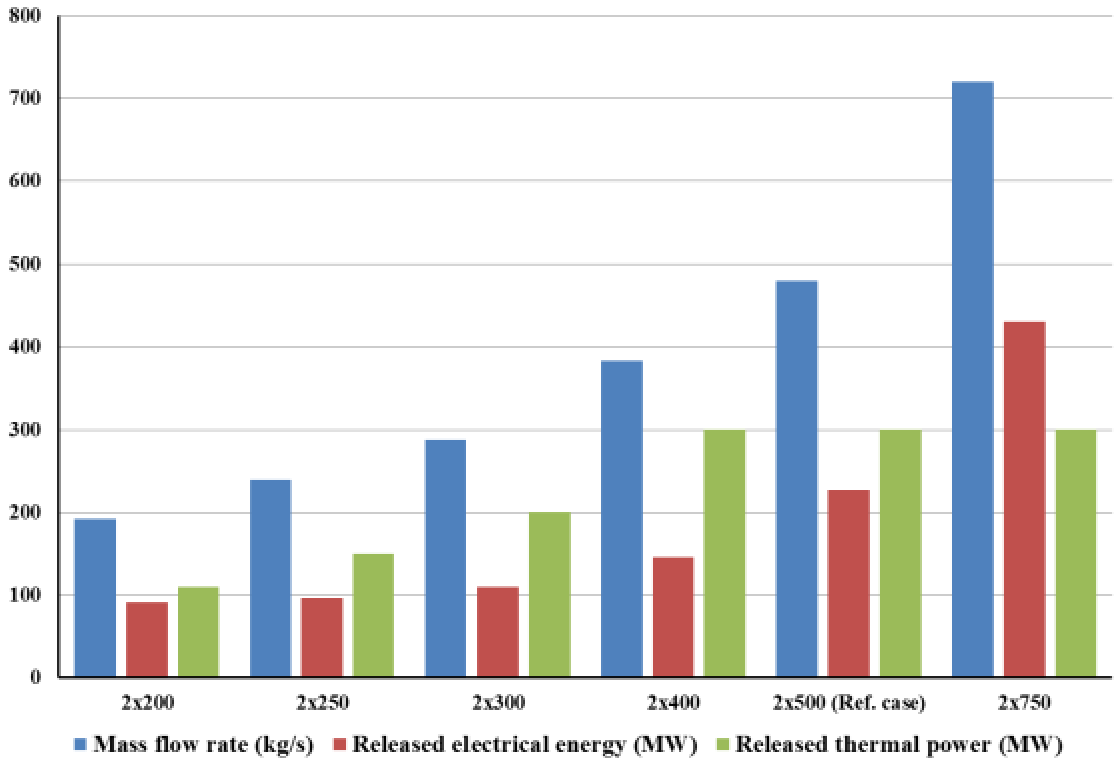


Figure 27: The mass flow rate, released electrical and thermal power for Case 1

Table 8 and **Figure 28** show the results of CT simulations for Case 2. It can be seen that the released electrical power is constant (144 MWe) while the released thermal power increases monotonically (see in **Figure 28**). This case is not as realistic as Case 1.

	Heat Source (MW)					
Parameters / Configuration	2x200	2x250	2x300	2x400	**2x500**	2x750
Mass flow (kg/s)	192	240	288	384	**480**	720
Released electrical energy (MW_e)	144	144	144	144	**144**	144
Live steam pressure (bar)	169	169	169	169	**169**	169
Live steam temperature (°C)	570	570	570	570	**570**	570
HP heat output circuit pressure (bar)	140	140	140	140	**140**	140
HP heat output circuit temperature (°C)	336.6	336.6	336.6	336.6	**336.6**	336.6
MP heat output circuit pressure (bar)	45	45	45	45	**45**	45
MP heat output circuit temperature (°C)	257.44	257.44	257.44	257.44	**257.44**	257.44
LP heat output circuit pressure (bar)	18	18	18	18	**18**	18
LP heat output circuit temperature (°C)	207.12	207.12	207.12	207.12	**207.12**	207.12
Released P_{th} in the 1st circuit (MW_{th})	0	30	30	187.5	**375**	750
Released P_{th} in the 2nd circuit (MW_{th})	0	0	50	100	**100**	100
Released P_{th} in the 3rd circuit (MW_{th})	0	0	30	50	**50**	50
Released thermal power (MW_{th})	0	30	110	337.5	**525**	900

Table 8: The simulation results of CT for Case 2 (reference case marked by bold text)

Case 2 plays rather a demonstrative role for comparison. While the spare generated electricity can be sold through the electrical grid on a lower price in Case 1 till the spare amount of heat could hardly be sold out in the vicinity of the site in such huge amount as in case of 2x500 or 2x750 configurations. The transport of process steam on a long distance is not feasible either due to the high heat and pressure losses. Some configurations (e.g. Helium loop) for heat transportation could allow higher distances, however the technical and economic aspects have not been investigated due to lack of data for such evaluation.

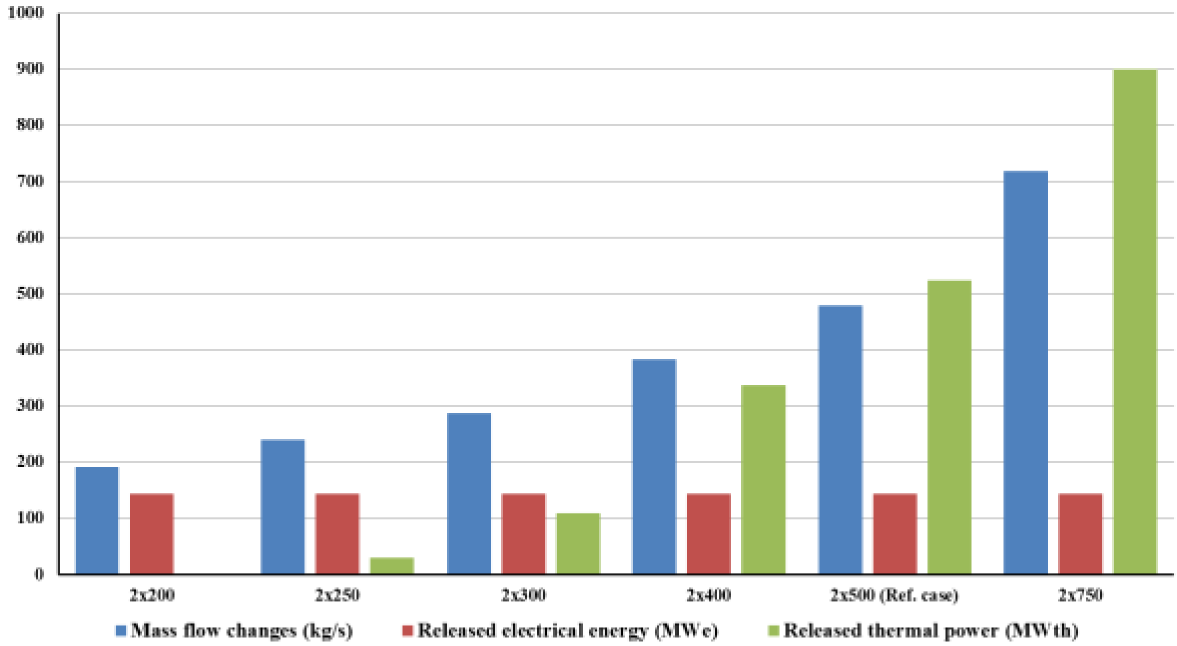


Figure 28: The mass flow rate, released electrical and thermal power for Case 2

Figure 29 shows the thermal versus the electrical (T/E) ratio for the two cases. For Case 1 (blue curves in **Figure 29**) the optimal T/E ratio is around 3 in case of a 2x500 MW twin HTR unit configuration (the T/E ratio is maximal here, R2 >0.95). For Case 2 (red curves in **Figure 29**) the optimal T/E ratio is around 2.75 in case of 2x400÷2x500 MW twin HTR unit configurations (R2 >0.99).

Summarizing the above findings, the optimal nominal capacity is in the range of [2x400 2x500] MW where the T/E ratio optimal which means T/E reaches its maximum value (see **Figure 29**).

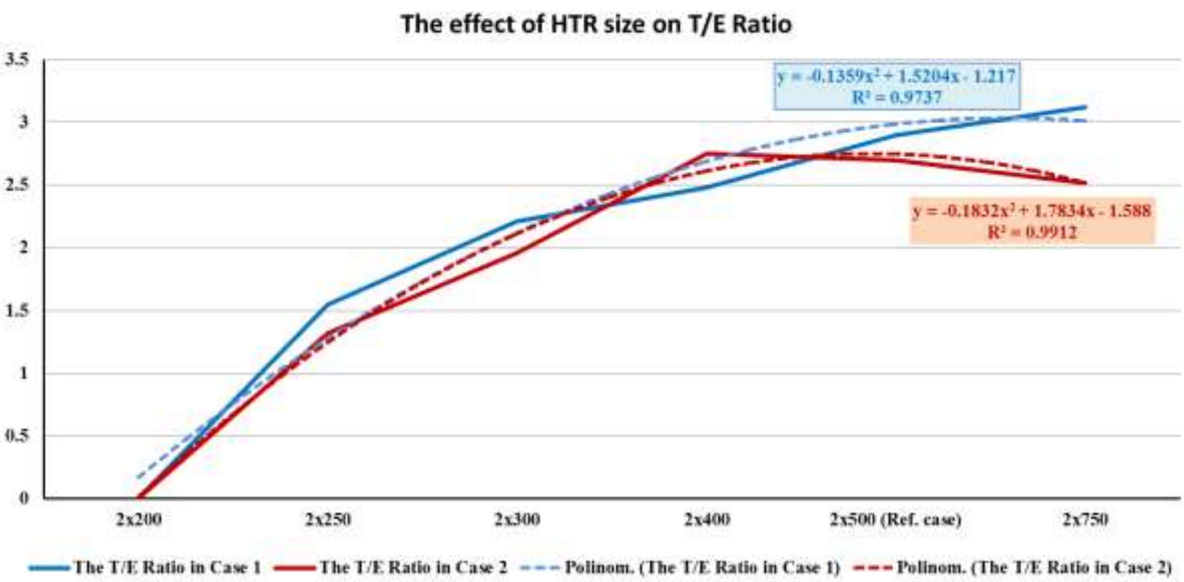


Figure 29: The effect of HTR size on the T/E ratio

It means that if the heat demand increases for a short time period then in case of the 2x400 and 2x500 configurations less electrical power fall occur than in case of smaller twin unit size. Regarding the AREVA HTR design (nominal capacity 625 MW, 1 or 2 units), its size seems close to optimal (see **Figure 29**). So, in the sense of T/E ratio the AREVA HTR design represents a good chose.

4.3.2 The effect of HTR size on the economics

Because Case 2 is rather a theoretical case for comparison purpose, only Case 1 has been used to investigate the effect of HTR size on the economics. The released thermal and electrical powers can be seen in **Figure 30** for Case 1.

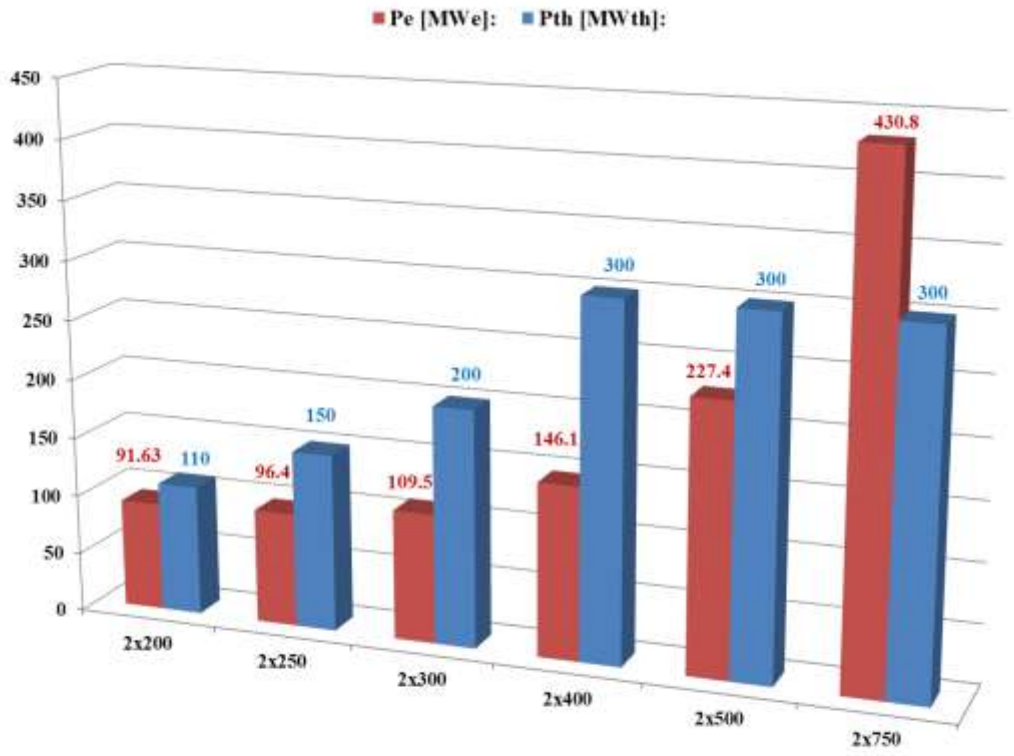


Figure 30: The released thermal and electrical power in case of the six configurations

Only one nominal capacity (of the 2x250 configuration) equals to the reference configuration of the economic assessment study (see in **Table 4**). Thus, many parameters, mainly the costs of the other five configurations differ from the reference case defined in **Table 5**. **Table 9** lists the differences.

The different colours in **Table 9** indicate certain changes compared to the reference configuration (marked by grey background). One exception is the blue mark which means no change or equivalence to the reference parameters. Red mark means the parameter is lower while green mark means the parameter is higher than the corresponding reference parameter. The percent value after the different parameter value shows the deviation from the reference parameter in percent. The "+2% inf. 10 y" text means that all indicated parameter values were increased 2% of inflation over 10 year (see in **Table 9**). The difference in heat and electricity prices was not listed in **Table 9**, because it is defined in **Figure 31.**

Figure 31 shows the NPV values for the six different configurations. Here the parameter is the heat and electricity prices which cause big differences between the points of different price scenarios. It is worth to note that the „rules" that drive the electricity prices (mostly driven by capacities and electricity market) are different from the rules for heat price (mostly driven by CO2 and fuel costs).

Parameter	2x200	2x250	2x300	2x400	2x500	2x750
HTR construction costs in year 0	**1-4: 791.18 -15% 5-6: 964.4 -15% +2% inf. 10 y**	**1-4: 930.8 0% 5-6: 1134.64 +2% inf. 10 y**	**1-4: 1070.42 +15% 5-6: 1304.84 +15% +2% inf. 10 y**	**1-4: 1349.66 +45% 5-6: 1645.23 +45% +2% inf. 10 y**	**1-4: 1628.9 +75% 5-6: 1985.62 +75% +2% inf. 10 y**	**1-4: 2327 +150% 5-6: 2836.6 +150% +2% inf. 10 y**
O&M costs in year 0	**1-4: 19.89 -15% 5-6: 24.25 -15% +2% inf. 10 y**	**1-4: 23.4 0% 5-6: 28.52 +2% inf. 10 y**	**1-4: 26.91 +15% 5-6: 32.8 +15% +2% inf. 10 y**	**1-4: 33.93 +45% 5-6: 41.36 +45% +2% inf. 10 y**	**1-4: 40.95 +75% 5-6: 49.92 +75% +2% inf. 10 y**	**1-4: 58.5 +150% 5-6: 71.31 +150% +2% inf. 10 y**
Decommissioning costs in year 0	**1-4: 97.75 -15% 5-6: 119.157 -15% +2% inf. 10 y**	**1-4: 115 0% 5-6: 140.2 +2% inf. 10 y**	**1-4: 132.25 +15% 5-6: 161.212 +15% +2% inf. 10 y**	**1-4: 166.75 +45% 5-6: 203.267 +45% +2% inf. 10 y**	**1-4: 201.25 +75% 5-6: 245.32 +75% +2% inf. 10 y**	**1-4: 287.5 +150% 5-6: 350.461 +150% +2% inf. 10 y**
Fuel costs in year 0	**1-4: 23.035 -15% 5-6: 28.08 -15% +2% inf. 10 y**	**1-4: 27.1 0% 5-6: 33.03 +2% inf. 10 y**	**1-4: 31.165 +15% 5-6: 37.99 +15% +2% inf. 10 y**	**1-4: 39.295 +45% 5-6: 47.9 +45% +2% inf. 10 y**	**1-4: 47.425 +75% 5-6: 57.81 +75% +2% inf. 10 y**	**1-4: 67.75 +150% 5-6: 82.59 +150% +2% inf. 10 y**
Released thermal power	**110**	**150**	**200**	**300**	**300**	**300**
Released electrical power	**91.63**	**96.4**	**109.5**	**146.1**	**227.4**	**430.8**

Table 9: The differences between the reference case (its column marked by grey background) and the other configurations

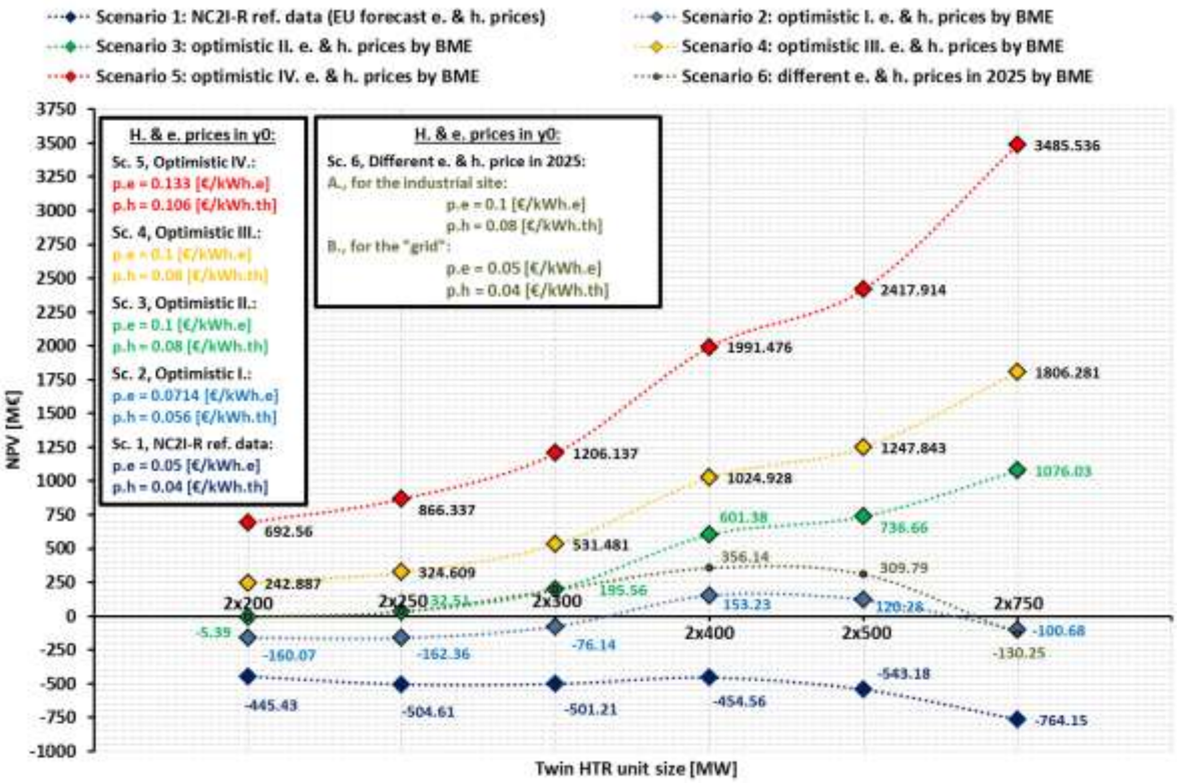


Figure 31: The dependency of NPV on the heat (h.) and electricity (e.) prices in case of the Chemelot site (NL)

The NC2I-R reference data (see **Table 4** and in (European Commission, 2013)) seem to be the most pessimistic in the sense of the average heat and electricity prices. These prices equal to the average heat and electricity prices reported in (European Commission, 2013) for the EU. This data gives the lowest NPV values for each configuration (dark blue points in **Figure 31**). Here, the highest NPV appears at the 2x200 and 2x400 configurations.

If the optimistic I average heat and electricity prices are used (see the light blue points in **Figure 31**) then the NPV values at 2x400 and 2x500 configurations exceed 0 and rise into the positive range. Here, the highest NPV appears at the 2x400 and 2x500 configurations which coincide with the final outcome of the previous investigation about the effect of HTR size on the T/E ratio and NPV.

If the optimistic II, III or IV average heat and electricity prices are used (see the green, yellow and the red points in **Figure 31**) then the NPV values exceed 0 and lay in the positive range. Here, the highest NPV appears at the 2x400, 2x500 and 2x750 configurations.

If we make difference between the heat and electricity prices for the industrial site (generally these prices are higher by saving the transmission costs, which can be higher that 40% of the total price) and for the spare energy sold through the grid, then we get a more realistic picture of the economics (see the little dark green points in **Figure 31**). Here the NPV values for 2x200 and 2x250 configurations are close to 0. The NPV for the configuration of 2x300 is around 185 M€. The NPV reaches its maximum value at the configuration of 2x400. Further increase in the nominal capacity of the configuration causes a fall in the NPV value (see for e.g. the 2x500 and 2x750 configurations in **Figure 31**) due to the increasing construction-, fuel- and O&M costs. The NPV value falls down significantly in case of 2x750 configuration, because the spear electricity (above the 180 MWe demand of the site) has been sold on a much lower electricity price (0.05 €/kWh) and give only lower addition to the NPV while the costs (construction-, fuel- and O&M-) are the highest for this configuration.

So, based on the most sophisticated prices (“Scenario 6: different e. & h. prices in 2025 by BME” in **Figure 31**) and the HTR250 design (AREVA GmbH, 2014) it can be pointed out that the optimal HTR size in the sense of economics is around the 2x400÷2x500 configurations. This finding coincides with the final outcome of the investigation for optimal T/E ratio.

Furthermore, based on the overall picture shown in **Figure 31**, a HTR unit can be profitable but it depends strongly on the heat and electricity prices what the produced heat and electricity sold to the industrial site and the neighbourhood through the electrical and district heating grids.

4.4 The economics of potential sites

Based on the European site mapping task (Task 4.2) of the project (NC2I-R - D4.21, 2015), two Polish sites have been chosen for further investigation assisted by the coupled heat schema-economic model.

The first site is at Gdansk which has the bigger energy demand both in the dimension of process heat and electricity (see in **Table 10**). The second site is at Trzebinia. Its energy demand is much lower than that of Gdansk (see also in **Table 10**).

Site location	Electric power consumption after 2016	Thermal power usage after 2016	p_1 [bar]	p_2 [bar]	p_3 [bar]	T_1[°C]	T_2[°C]	T_3[°C]	Mass flow rate [kg/s]
Gdańsk	22	246	1.9	1.9	0.45	340	250	200	152
Trzebinia	4.4	39	1.96	1.6	0.6	270	250	170	24.306

Table 10: The heat and electricity demand of the two Polish sites [3]

Four-four different heat and electricity price pairs have been used to both sites. One extra pair of prices was used for Gdansk site which is equal to the sixth pair of price at the Chemelot site ("Realistic with different e. & h. price in 2025 by BME" in **Figure 31**).

4.4.1 The investigation for the Gdansk site

First, the Gdansk site was analysed. Two configurations were selected based on the energy demand for this site, the 2x250 (realistic) and the 2x300 (for comparison purpose to parameter study) configurations. Each configuration has been evaluated with two different sets of heat schema parameters:

- the first set represents lower thermodynamic values (see in **Table 11**),
- the second set represents higher thermodynamic values (see in **Table 12**).

Parameters	Gdansk 2x250	Gdansk 2x300
Mass flow (kg/s)	152	182.4
Live steam pressure (bar)	79	79
Live steam temperature (°C)	510	510
Released electrical energy (MW_e)	30.38	38.21
Released thermal power (MW_{th})	232	282

Table 11: The lower thermodynamic parameters for Gdansk site

Parameters	Gdansk 2x250	Gdansk 2x300
Mass flow (kg/s)	240	288
Live steam pressure (bar)	169	169
Live steam temperature (°C)	570	570
Released electrical energy (MW_e)	131.78	159.69
Released thermal power (MW_{th})	232	282

Table 12: The higher thermodynamic parameters for Gdansk site

The higher heat schema parameters (which can be seen in **Table 12**), can be considered as optimized parameters for higher released electrical power (see in **Figure 32** for comparison). As it can be seen in **Figure 32**, 90 bar and 60°C increment in the state variables of the live steam parameters cause more than 100 MWe rise in the released electrical power. This rise increases the NPV which is very desirable.

It was mentioned previously that five different pairs of energy price have been applied and investigated for the Gdansk site. The first pair of prices equal to the prices used in the economic assessment study (NC2I-R - D4.11, 2015) (see in **Figure 33** and **Figure 34** as “NC2I-R reference h.&e. price, lower p&T”).

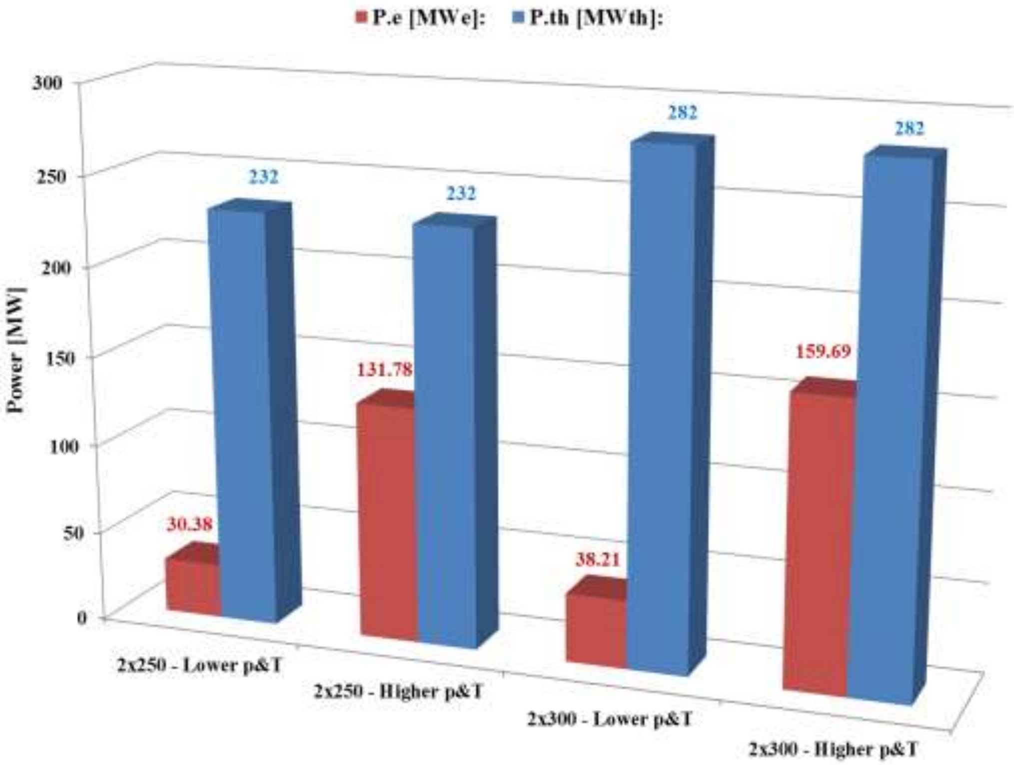


Figure 32- The released heat and electrical power in case of Gdansk site

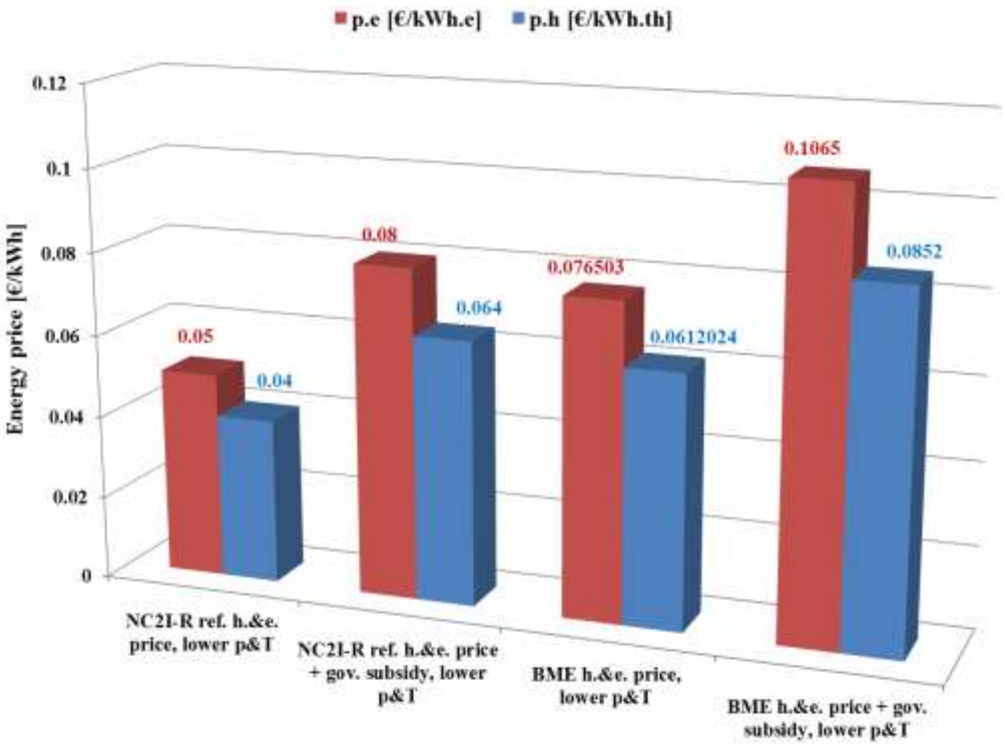


Figure 33- The pair of energy prices for the Gdansk site

At the second pair of energy prices, governmental subsidiary was assumed. Thus, a +0.03 €/kWh subsidy (+60%) was added to the price of electricity. A proportional (+60%) heat price was assumed here resulting in 0.64 €/kWh as heat price (see in **Figure 33** and **Figure 34** as “NC2I-R reference h.&e. price + gov. subsidy, lower p&T”).

The third pair of energy prices came from a very optimistic estimation of BME NTI on the average energy prices in the EU in 2025 (see in **Figure 33** and **Figure 34** as “BME h.&e. price, lower p&T”).

The fourth pair of energy prices has been derived from the third adding +0.03 €/kWh to the electricity price similar to the second case. The heat price was defined here as the 80% of the current electricity price (see in **Figure 33** and **Figure 34** as “BME h.&e. price + gov. subsidy, lower p&T”).

The fifth pair of prices has already been used in case of the Chemelot site. It was the sixth pricing method where different pairs of prices have been used in case of provided energy to the industrial site and to the grid (see in **Figure 31** as “Scenario 6: different e. & h. prices in 2025 by BME”).

The above defined five different pairs of prices can be seen in **Figure 33** and **Figure 34**.

The values of the costs for the 2x250 configuration are the same than it can be seen in **Table 4**. For the other configuration, the costs are equal to the values which can be seen in **Table 9** at the configuration of 2x300 in the lines for the 1-4 prices (for e.g. the construction cost equals to 1070.42 M€).

Figure 34 shows the NPV values for the different pairs of prices in case of the lower and higher thermodynamic parameters. The points are above 0 M€ except the two lower p&T cases calculated with the NC2I-R reference pair of prices. All other points are above 0 M€, which means the investment will produce some profit and worth to invest money into the installation of twin HTR unit.

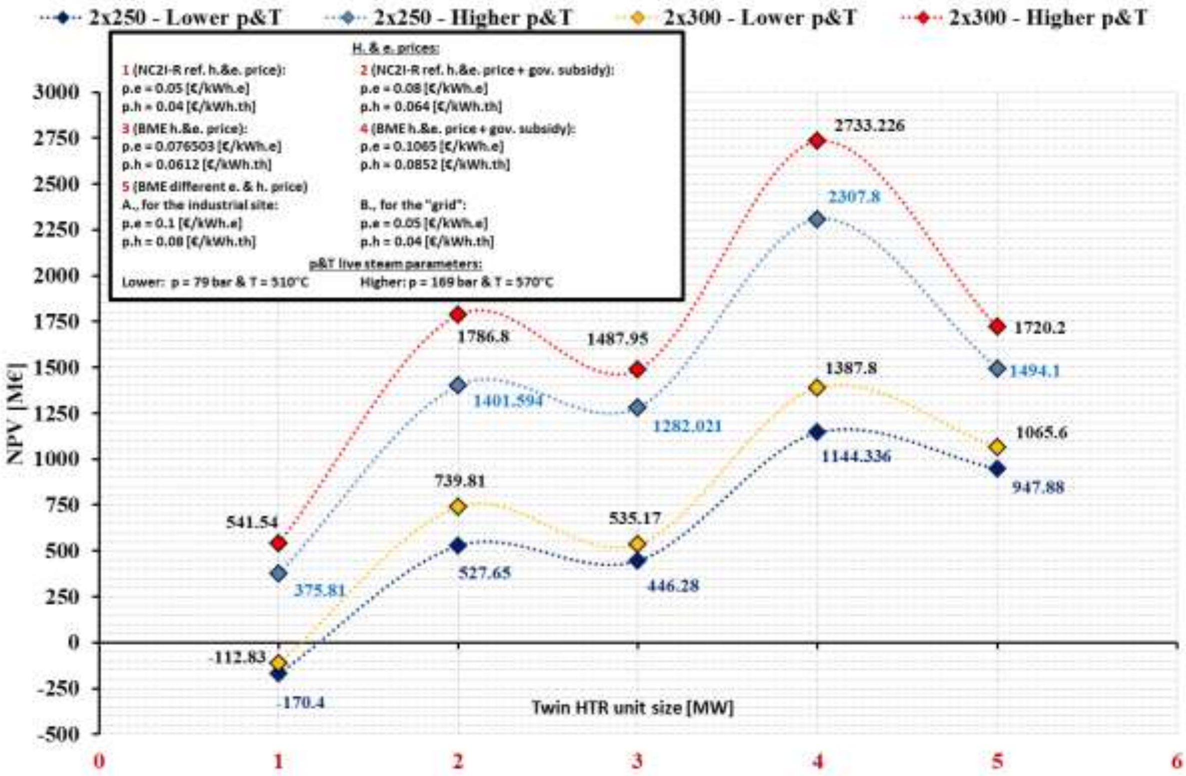


Figure 34- The dependency of NPV on energy prices and p&T live steam parameters in case of Gdansk site (PL)

The governmental subsidy helps a lot to the profitability of the investment (see in **Figure 34** to **Figure 38**). As it can be seen the subsidy pushes the points away from the horizontal axis (compare the points of the 1st-2nd and 3rd-4th prices). So, subsidy paid by the government is a very effective measure to make a twin HTR unit attractive for potential investors.

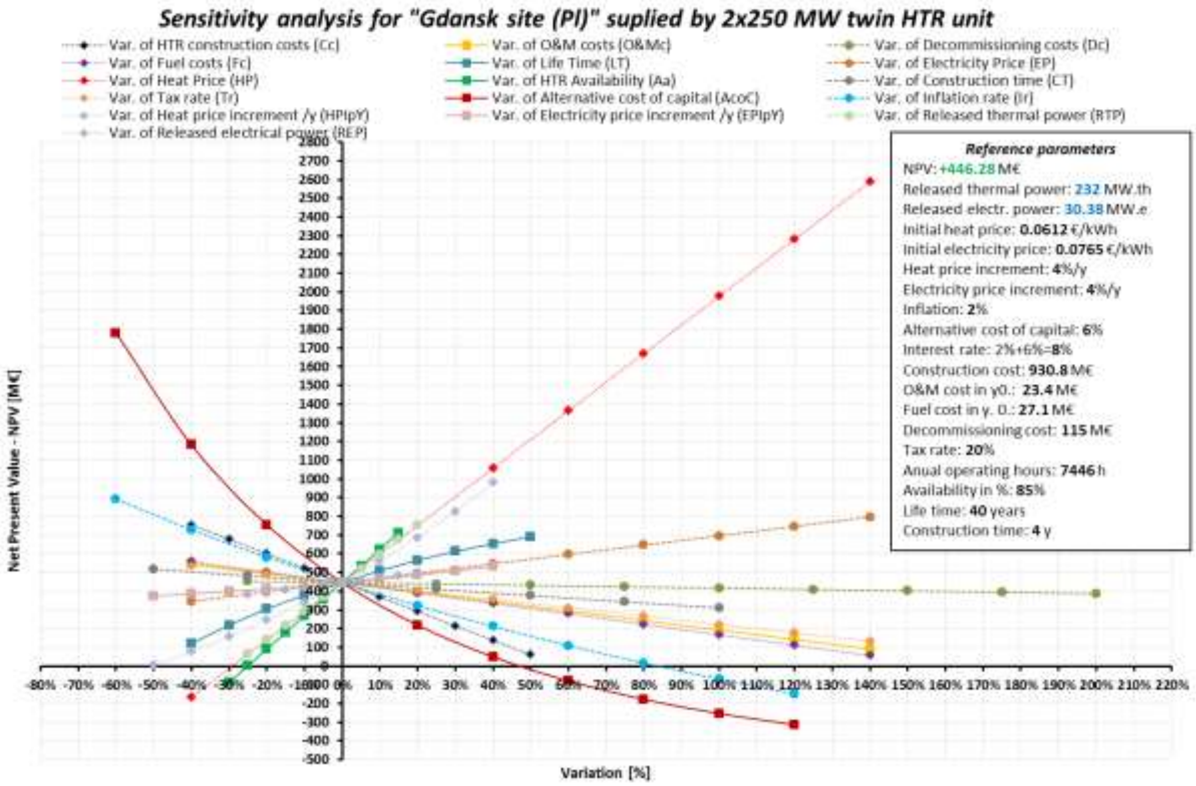


Figure 35- The sensitivity of NPV in case of a 2x250 configuration at the Gdansk site (“BME h.&e. price, lower p&T” in Figure 34)

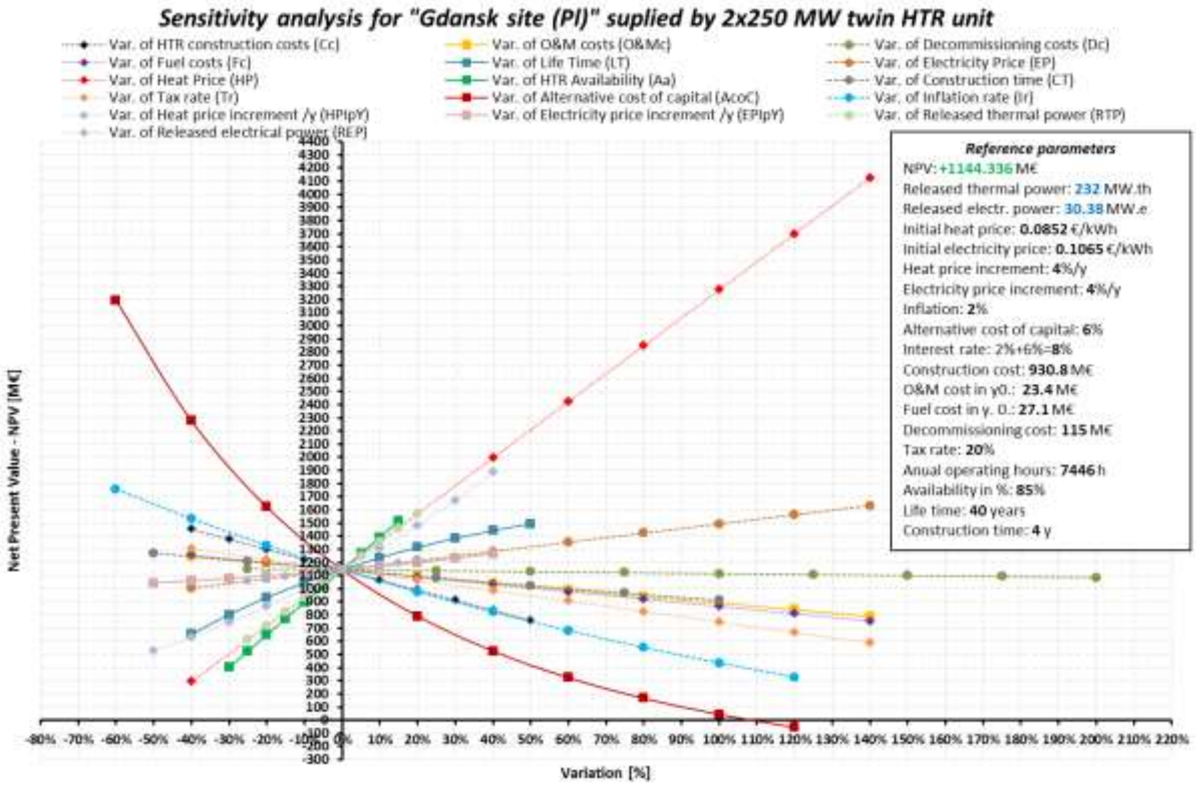


Figure 36- The sensitivity of NPV in case of a 2x250 configuration at the Gdansk site (“BME h.&e. price + gov. subsidy, lower p&T” in Figure 34)

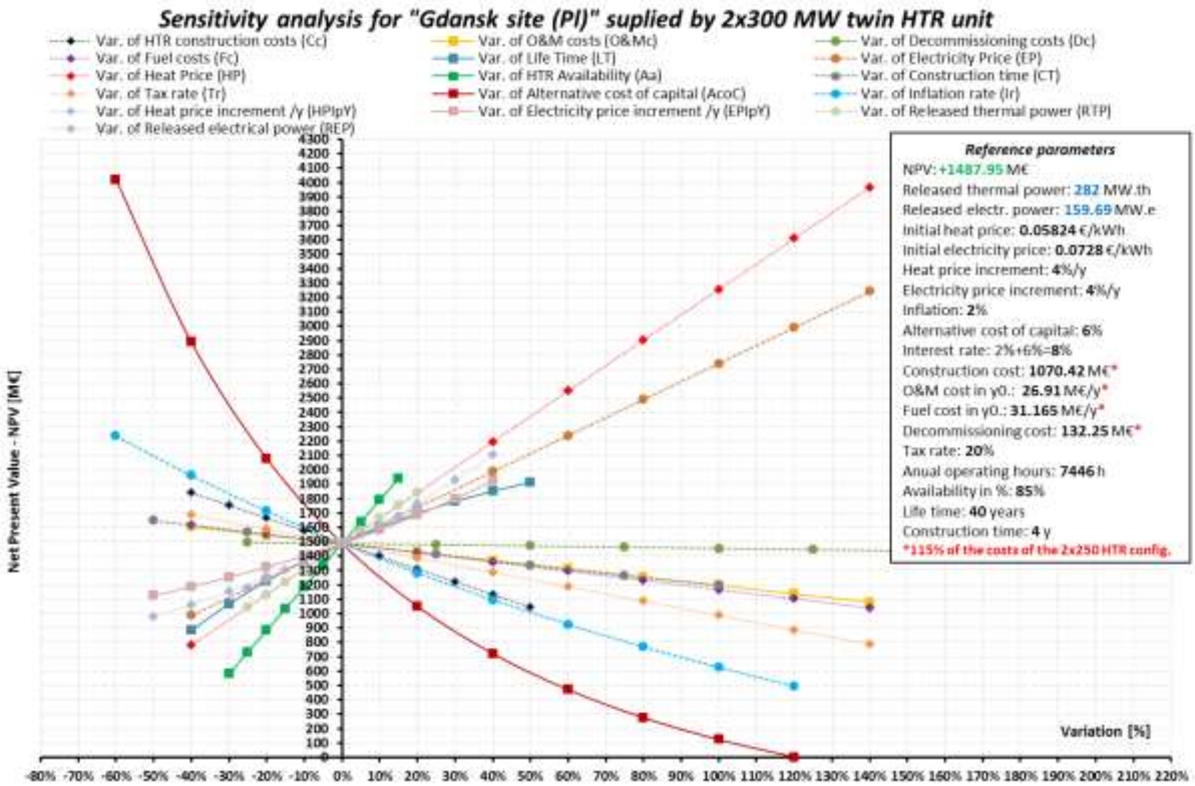


Figure 37- The sensitivity of NPV in case of a 2x300 configuration at the Gdansk site (“BME h.&e. price, higher p&T” in Figure 34)

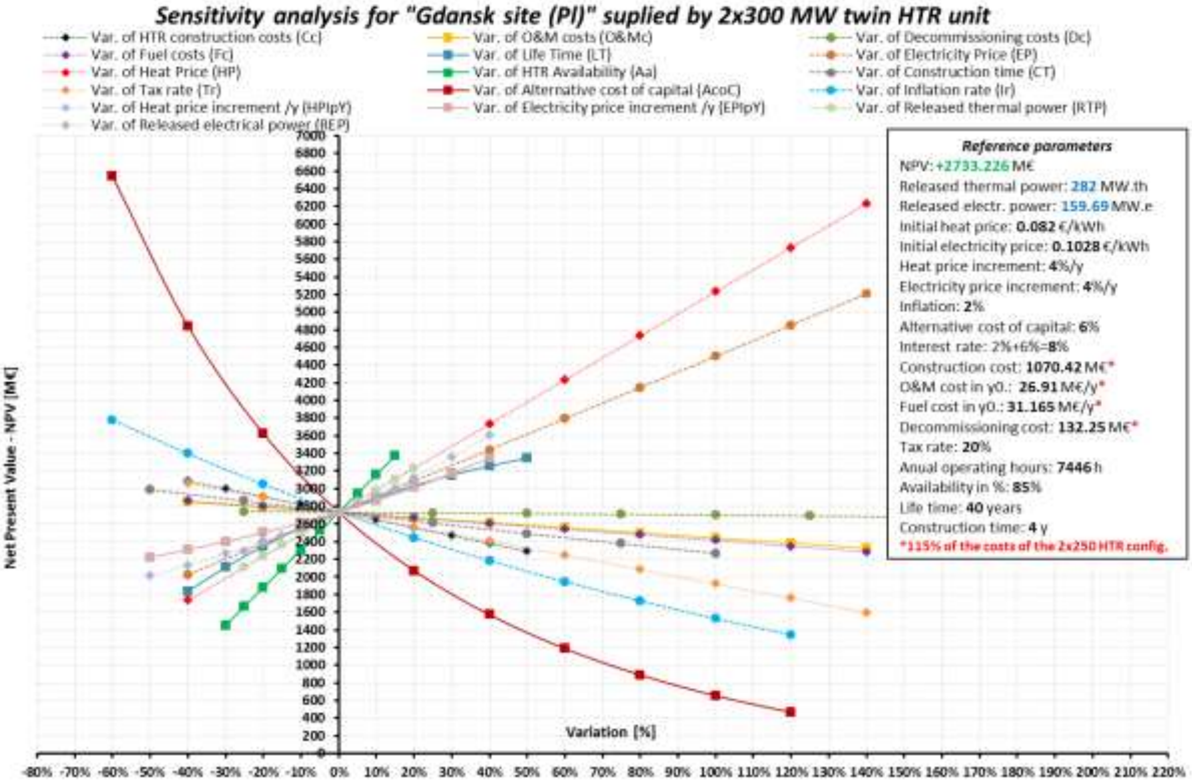


Figure 38- The sensitivity of NPV in case of a 2x300 configuration at the Gdansk site ("BME h.&e. price + gov. subsidy, higher p&T" in Figure 34)

If the HTRs operate with higher thermodynamic parameters then the NPV values are higher with 58÷400 M€ (see in **Figure 34**). The higher the energy prices the bigger the NPV increment. It means that the planed HTRs should work on as high thermodynamic parameters as possible to increase the released electrical energy which generates extra revenue after sold electricity on the grid (even if its price lower than the electricity price what the industrial site pays).

The results got with the fifth pair of prices show lower NPV values compared to the results got with the fourth (see in **Figure 34**), but it is more realistic and closer to the real case. But what is more important these NPV values are very high (between 947.88÷1720.2 M€) which can be very attractive for potential investors even if the fifth pair of energy price seems a bit too optimistic as well as the costs considered (see **Table 4** and **Table 5**).

4.4.2 The investigation for the Trzebinia site

The second Polish site is at Trzebinia. Here the industrial energy demand is about one sixth of the demand at Gdansk. Five configurations were selected for investigation based on the energy demand for this site: the 2x50, 2x100, 2x150, 2x200 and the 2x250 configurations. Each configuration has been evaluated with two different set of heat schema parameters similar to the Gdansk site:

- the first set represents lower thermodynamic values (see in **Table 13**),
- while the second set represents higher thermodynamic values (see in **Table 14**).

Parameters	**2x50**[2]	**2x100**[2]	**2x150**[2]	**2x200**[2]	**2x250**[2]
Mass flow (kg/s)	7	14	21	28	35
Live steam pressure (bar)	39	39	39	39	39
Live steam temperature (°C)	390	390	390	390	390
Released electrical energy (MW_e)	0.434	1.29	2.162	2.857	4.84
Released thermal power (MW_{th})	10	20	28	37	43

Table 13: The lower thermodynamic parameters for Trzebinia site

Parameters	**2x50**	**2x100**	**2x150**	**2x200**	**2x250**
Mass flow (kg/s)	48	96	144	192	240
Live steam pressure (bar)	169	169	169	169	169
Live steam temperature (°C)	570	570	570	570	570
Released electrical energy (MW_e)	27.54	68.16	108.78	149.4	190.02
Released thermal power (MW_{th})	43	43	43	43	43

Table 14: The higher thermodynamic parameters for Trzebinia site

Similar to the Gdansk site, the higher heat schema parameters (which can be seen in **Table 14**), can be considered as optimized parameters in order to increase the released electrical power (see in **Figure 39** for comparison). As it can be seen in **Figure 39**, 130 bar and 180°C increment in the state variables of the live steam parameters cause a huge rise in the released electrical power. The bigger this rise, the bigger the nominal capacity of the HTR. This increment increases the NPV as well.

[2] The efficiencies for these configurations are very low, less than 10%, which would very likely cause problem in heat provide

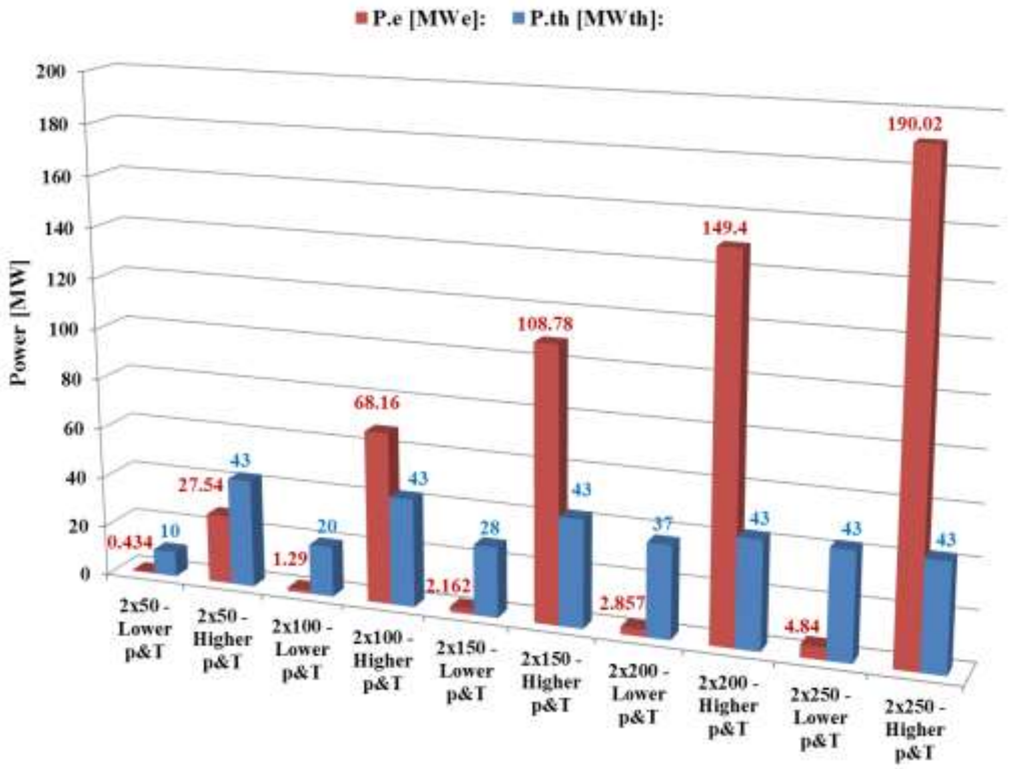


Figure 39- The released heat and electrical power in case of Trzebinia site

Five different pairs of energy price have been applied and investigated for the Trzebinia site similar to the Gdansk site (see in **Figure 33** and **Figure 34**).

The values of the costs for the five configurations can be seen in **Table 15**. The configuration of 2x250 has the same costs as the reference case in the economic assessment study (NC2I-R - D4.11, 2015) while the others have decreased costs by 15%, 30%, 45% and 60% respectively.

Parameter	2x50	2x100	2x150	2x200	2x250
HTR construction costs in year 0	372.32 -60%	511.95 -45%	651.56 -30%	791.18 -15%	930.8
O&M costs in year 0	9.36 -60%	12.87 -45%	16.38 -30%	19.89 -15%	23.4
Decommissioning costs in year 0	46 -60%	63.25 -45%	80.5 -30%	97.75 -15%	115
Fuel costs in year 0	10.84 -60%	14.905 -45%	18.97 -30%	23.035 -15%	27.1

Table 15: The used pair of prices for Trzebinia site

Figure 40 shows the NPV values for the different pairs of prices in case of the lower and higher thermodynamic parameters. As it can be seen the points are below or above the horizontal axis. It means that the profitability of the investment is not univocal and strongly depends on the energy prices and live steam thermodynamic parameters. So, for a site with lower energy demand like Trzebinia, it seems that the HTR is not the only and best option. In case of higher energy prices, high thermodynamic parameters applied and long term governmental subsidy, the investment could be worth for realization (zero or positive NPV) but still represents high risks.

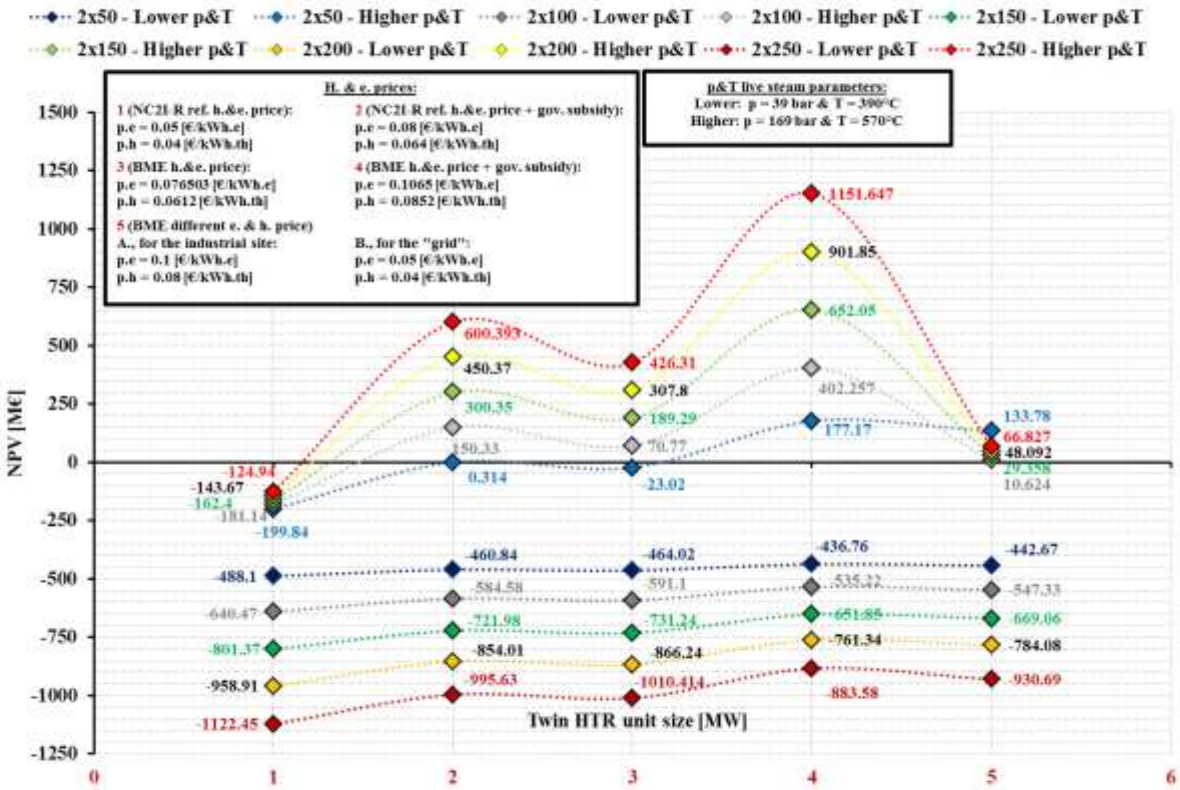


Figure 40- The dependency of NPV on energy prices and p&T live steam parameters in case of Trzebinia site (PL)

These risks can be seen in the further figures (see **Figure 41** to **Figure 44**). It is obvious that the cases with the lower pressure and temperature parameters are neither good solution in engineering sense nor economically attractive (see **Figure 41** and **Figure 42**). Only the cases with higher parameters seem to be economically viable (see **Figure 43** and **Figure 44**).

One more interesting fact can be seen in **Figure 40**. It is that the higher the nominal capacity the lower the NPV values in case of lower p&T cases due to the increasing construction-, fuel and O&M costs (see in **Table 15**) and hardly increasing released and sold energy (see in **Figure 39**).

If the HTRs operate with higher thermodynamic parameters then the NPV values are higher with 288÷2000 M€ (see in **Figure 40**). The higher the energy prices the bigger the NPV increment. It means that the planed HTRs should work on as high thermodynamic parameters as possible to increase the released electrical energy which generates extra revenue after sold electricity on the grid (even if its price is lower than the industrial electricity price) similar to the Gdansk site.

The results got with the fifth pair of prices show lower NPV values compared to the results got with the fourth (see in **Figure 40**), but it is more realistic and closer to the real case. Here, the NPV values are very low and close to 0 (between 10.624÷133.78 M€) which can be moderately attractive for potential investors. The reason for the low NPVs in case of the fifth pair of price is that the spare energy sold through the grid adds limited value to the NPV while the costs increase significantly towards the bigger configurations (bigger nominal capacity). And the top of all that, the fifth pair of energy price seems to be a bit too optimistic which further decreases the attractiveness of this case for investors.

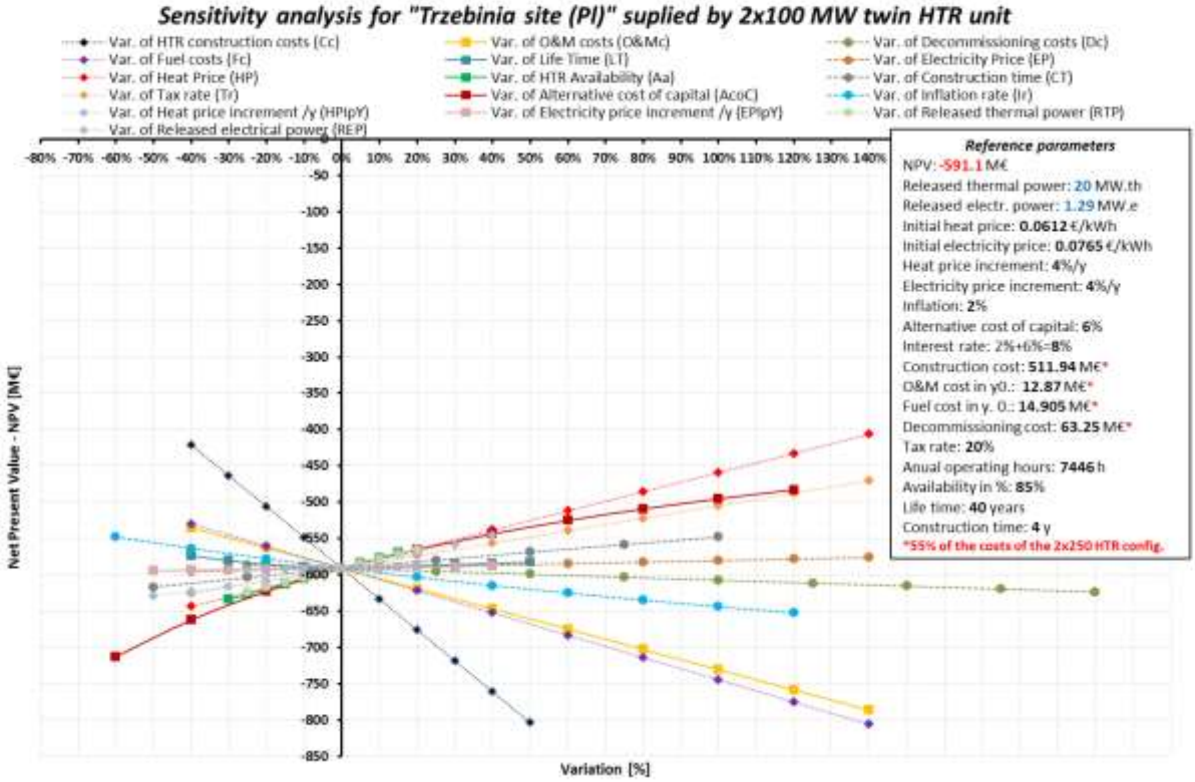


Figure 41- The sensitivity of NPV in case of a 2x100 configuration at the Trzebinia site (“BME h.&e. price, lower p&T” in Figure 40)

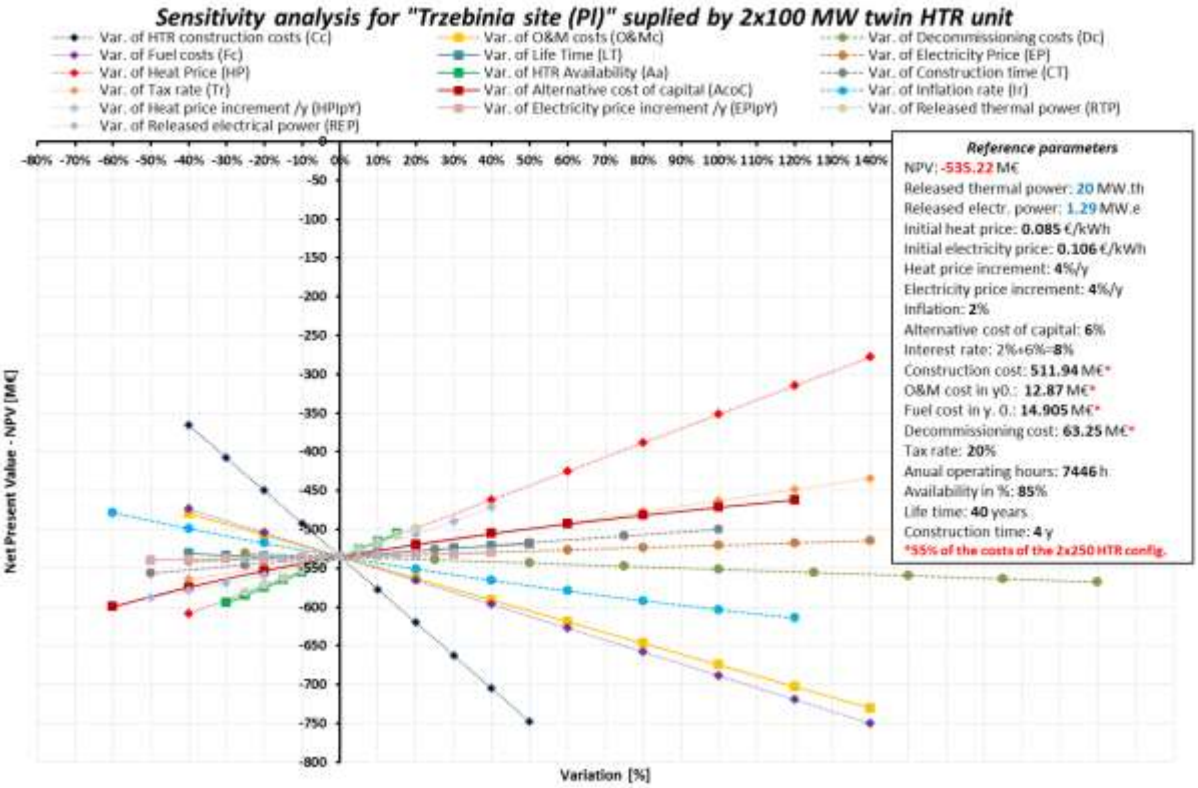


Figure 42- The sensitivity of NPV in case of a 2x100 configuration at the Trzebinia site (“BME h.&e. price + gov. subsidy, lower p&T” in Figure 40)

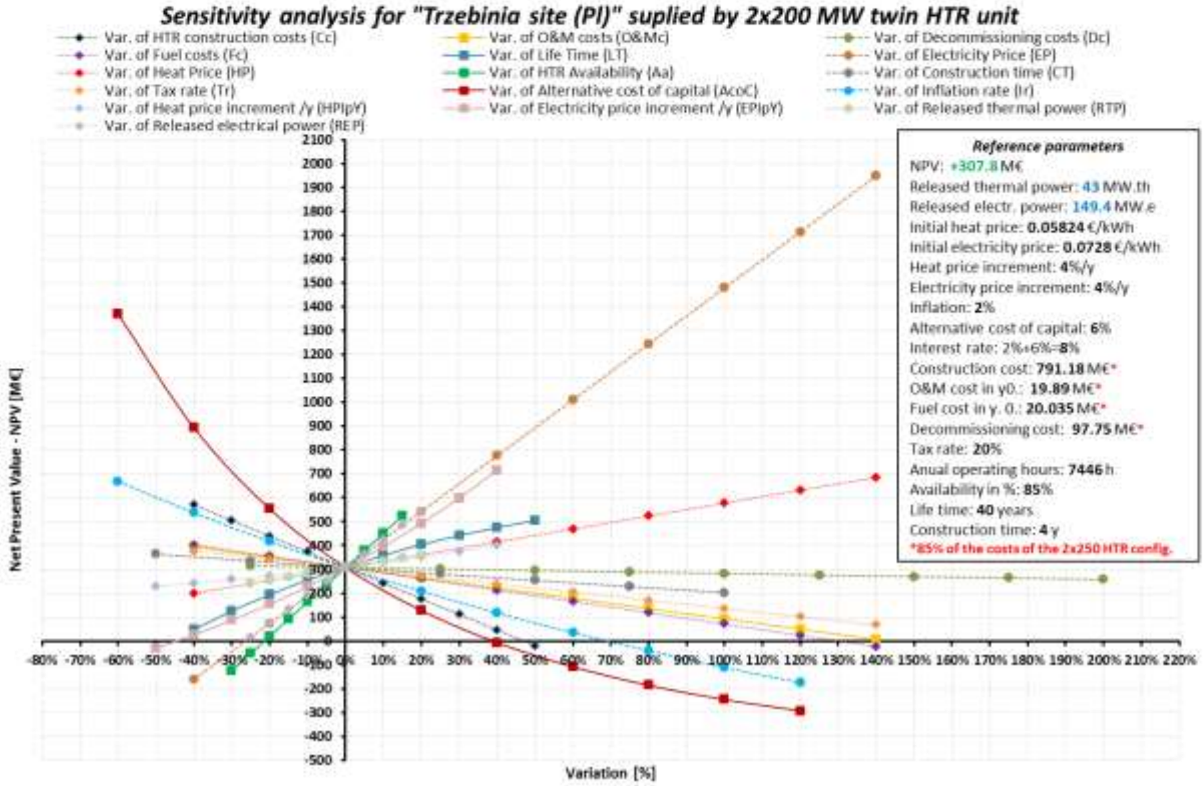


Figure 43- The sensitivity of NPV in case of a 2x200 configuration at the Trzebinia site (“BME h.&e. price, higher p&T” in Figure 40)

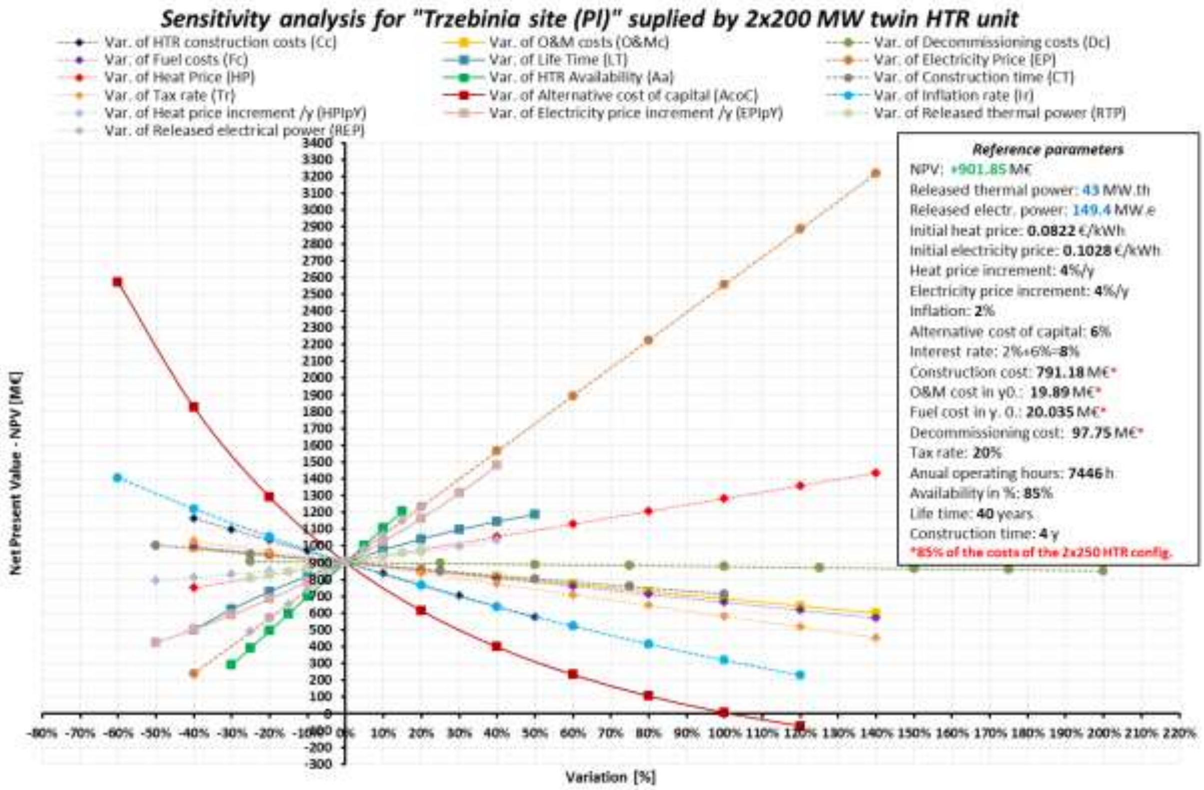


Figure 44- The sensitivity of NPV in case of a 2x200 configuration at the Trzebinia site (“BME h.&e. price + gov. subsidy, higher p&T” in Figure 40)

4.5 The evaluation of the two specific concepts

Two specific concepts were investigated to improve the economics of a twin HTR unit site. The first one is about a dynamic rate change between released thermal and electrical power depending on the current electricity price on the market. The second concept aims to store the energy produced by the twin HTR unit when the demand falls down and the electricity is cheap.

4.5.1 The dynamic handling of released energy ratio

This concept is based on the idea to change dynamically the ratio of released thermal and electrical energy depending on the value of the electricity price. If the electricity price is relatively high (during the top electricity demand period) then the twin HTR unit stops to release heat to the industrial site because it generates only electricity for both the site and the spare amount goes to the grid (see in **Table 16** and **Figure 45** as case A). In this case a back-up gas fired boiler starts and releases the required amount of heat to satisfy the heat demand of the industrial site.

Energy type / case	case A	case B	case C
Electricity price in year 0 [€/kWh]	0.053	0.036	0.049
Heat price in year 0 [€/kWh]	0.04		
Released electrical power [MW_e]	203.32 (*106.92**)	96.4	130 (*33.6**)
Released thermal power of HTR/gas fired boiler [MW_{th}]	0/150	150/0	80/70

Table 16: The energy prices of case A, B and C (*released to the grid)

If the electricity price descends below a certain (let's call it maximum) value (this period is in between two top demand periods, see in **Figure 45**) then the unit produce more heat than electricity for the site (see in **Table 16** and **Figure 45** as case B). If the electricity price falls below a certain minimum value (it is generally after the evening and before the morning top demand periods) then the unit releases more electricity than heat for the site and the neighbourhood while the spare amount (mainly electricity) goes to the grid (see in **Table 16** and **Figure 45** as case C).

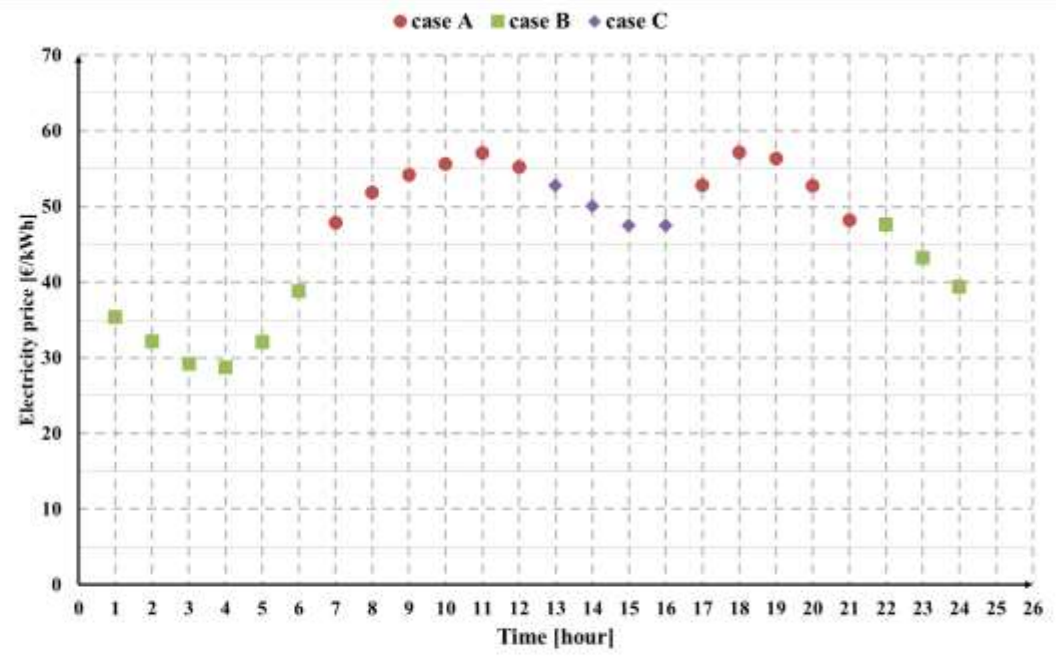


Figure 45- The daily distribution of the three cases based on the daily electricity price diagram
(data source: the period of 2009-2013, the Netherlands)

The imagined HTR unit would work discretely in one of the above mentioned three modes (one after the other) and in a predefined work schedule (see for e.g. in **Figure 45**).

The investigation has been performed for the 2x250 configuration. Due to the data of **Figure 45** relays on information from the Netherlands, it is obvious that an imaginary site located in the Netherlands has been assumed and used for this investigation. Therefore the Chemelot site was selected to serve as a basis for this case study.

Figure 46 and **Figure 47** shows the results of NPV sensitivity study for 16 parameters. These two figures are based on the parameters of the same site. The only difference between them is in the energy prices.

Figure 46 shows the sensitivity of NPV in the most pessimistic scenario for energy prices in case of the Chemelot site. Its reference value is -504.61 M€ (see in **Figure 31** as well). In case of higher energy prices (more fortunate scenarios) the NPV value is in between -162.36 and 866.337 M€ (see in **Figure 31** at 2x250 configuration).

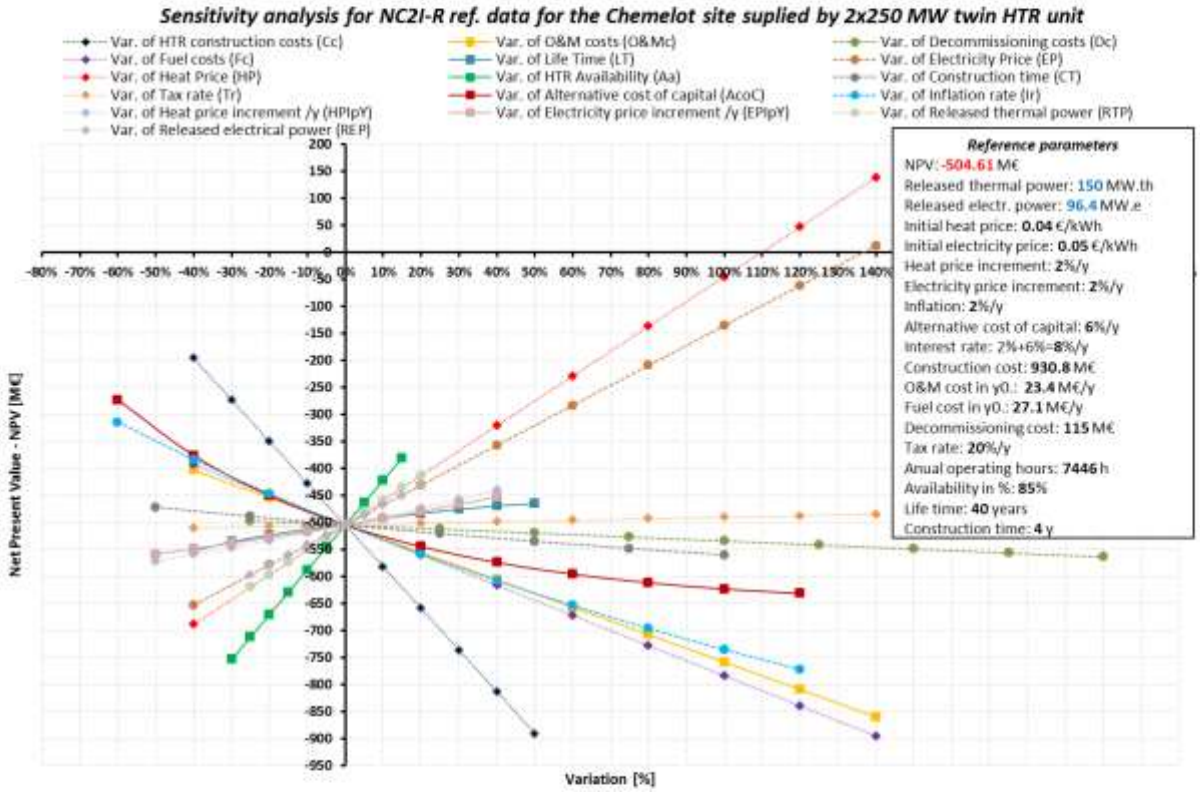


Figure 46- The sensitivity of NPV in case of a 2x250 configuration at the Chemelot site in normal run (“Scenario 1: NC2I-R ref. data (EU forecast e. & h. prices)” in Figure 31)

Figure 47 shows the sensitivity of NPV in case of the dynamic energy type change run. The reference value of the NPV in this case is -493.967 M€ which is slightly better than in normal run, but still disappointing. The increment between the investigated two types of run is only +10.643 M€ while the NPV still remains in very negative region. So, this type of run helps practically nothing in the sense of the NPV.

Based on the sensitivity of the NPV in both the normal and the dynamic energy type change runs, it seems unlikely that the investment in a twin HTR unit become profitable. Furthermore, the impact of the idea to increase the NPV by the dynamic energy type change run is very marginal.

It is worth to mention that the construction and the O&M costs of the gas fired boiler which can substitute the twin HTR unit has not been considered yet. Only the price of used amount of gas fuel has been taken into consideration in the economical calculation. If one considered these above mentioned costs (which occur in the reality) then the reference value of NPV of that dynamic energy type change run scenario would be worse than the current value and that of the normal run (see in **Figure 46**).

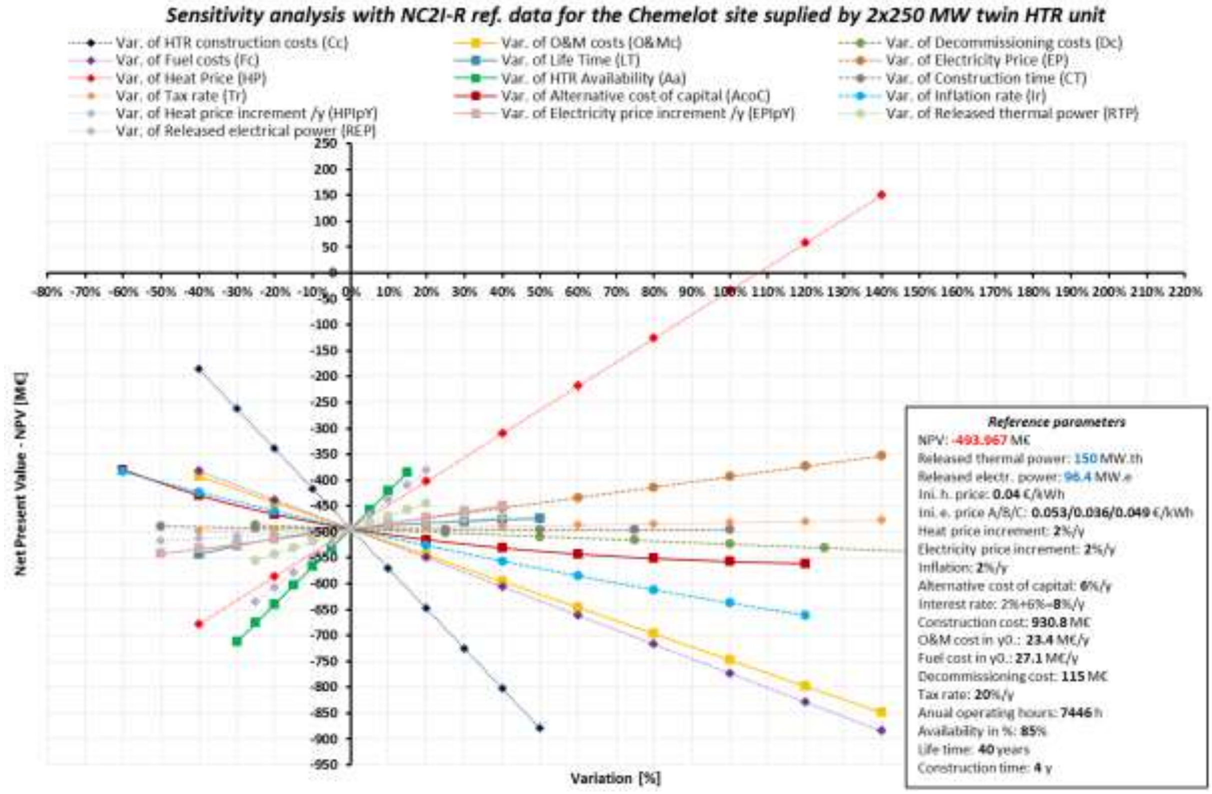


Figure 47-The sensitivity of NPV in case of a 2x250 configuration at the Chemelot site in dynamic energy type change run

4.5.2 The energy storage scenario

The second specific scenario is based on the idea to store the spare energy (mainly electricity during periods with low electricity price) into energy storage chemicals (for e.g.: hydrogen, methanol, ethanol, etc.) instead of releasing to the grid. After the disappointing result of the first specific scenario, this second one did not reached the phase of coupled heat schema – economic calculations due to the following reasons:

1. The efficiency of energy storage chemicals production has to be far less than 100% which decrease further the overall efficiency compared to the previous special case (the dynamic handling of released energy ratio). Thus the production of energy storage chemicals is very likely that would lead to a less profitable scenario (lower NPV) than the previous one.
2. This concept requires a very expensive new facility (for e.g.: a hydrogen-, methanol-, ethanol producer plant, or a pumped-storage plant, etc.) next to the twin HTR unit. The construction-, O&M costs of this new facility would decrease the overall NPV further.
3. Based on current practise and literature, the construction cost of an energy storage chemical producer or a pumped storage plant would transcend (or at least equal to) the cost of a gas fired boiler.
4. The market for energy storage chemicals either does not exists or very small.

4.6 Conclusions

The coupled heat schema – economic model has enabled us to identify the optimal T/E ratio and reactor size for a twin HTR unit and evaluate the economics of different sites (identified in the European Site Mapping task) with different configurations. Thus the creation and development of this coupled model is in itself a result of this work.

First, the verification of the coupled model has been carried out with good results. The economic models of E-ON, NWU and BME have given almost the same NPV values. They fall within the very narrow range of 1%. Furthermore, the difference between models is caused by rounding of intermediate calculation. Response to different input data shows a similar behaviour of the models. Therefore output results from the 3 models are consistent for comparison. So, the coupled model has been considered as suitably verified.

Next, in order to determine the optimal size of the twin HTR unit, the coupled model has been applied for a case study of the Chemelot site. Two aspects were investigated: the effect of HTR size on the thermal versus the electrical ratio (T/E) and the economics (NPV). The optimal nominal capacity is about 2x400, 2x500 MW where the T/E ratio optimal which means T/E reaches its maximum value around 2.75÷3. Concerning the economics, based on the most sophisticated prices it can be pointed out that the optimal HTR size in the sense of economics is around the 2x400÷2x500 configurations. This finding coincides with the final outcome of the investigation for optimal T/E ratio. It seems that a twin HTR unit can be profitable but it depends strongly on the costs (mainly on the construction cost), heat and electricity prices what the produced heat and electricity sold to the industrial site and the neighbourhood through the electrical and district heating grids.

Based on the European site mapping task of the project, two Polish sites have been chosen for further investigation assisted by the coupled heat schema-economic model. The first site is at Gdansk which has the bigger energy demand both in the dimension of process heat and electricity. The second site is at Trzebinia. Its energy demand is much lower than that of Gdansk. Four-four different heat and electricity pairs of prices have been used at both sites. One extra pair of prices was used which is equal to the sixth pair of price used previously at the Chemelot site.

First, the Gdansk site was analysed. Two configurations were selected based on the energy demand for this site, the 2x250 (realistic) and the 2x300 (theoretical) configurations. Each configuration has been evaluated with two different sets of heat schema parameters: the first set represents lower, while the second set represents higher thermodynamic values. The NPVs are above 0 M€ except the two lower pressure and temperature cases calculated with the pessimistic NC2I-R reference pair of price (“NC2I-R ref. h.&e. price”). All other points are above 0 M€, which means the investment will produce some profit and worth to invest money into the installation of twin HTR unit at Gdansk site.

The governmental subsidy in case of the Gdansk site helps a lot to the profitability of the investment because it pushes the NPV away from the horizontal axis. So, subsidy paid by the government is a very effective measure to make a twin HTR unit attractive for potential investors. Indeed, it is the trend observed for currents projects, where investors are edging the financial risks thanks to political support (subsidies, feed-in tariffs, long-term PPA, etc.). If the HTRs operate with higher thermodynamic parameters then the NPV values are higher with 58÷400 M€. The higher the energy prices the bigger the NPV increment. It means that the planed HTRs should work on as high thermodynamic parameters as possible to increase the released electrical energy which generates extra revenue after sold electricity on the grid (even if its price lower than the electricity price what the industrial site pays). The possible construction cost increasing effect of the need for more expensive structural materials due to the higher thermodynamic parameters has not yet investigated and taken into consideration. The results got with the fifth pair of prices (different prices for the energy provided to the industrial site and to the grid) show lower NPV values compared to the results got with the fourth (equal prices of energy provided to the site and to the grid), but it is more realistic and closer to the real case. But what is more important these NPV values are very high (between 947.88÷1720.2 M€) which can be very attractive for potential investors in case of a site with middle class energy demand just like the Gdansk site.

The second Polish site is at Trzebinia. Here the industrial energy demand is about one sixth of the demand at Gdansk. Five configurations were selected for investigation based on the energy demand for this site: the 2x50, 2x100, 2x150, 2x200 and the 2x250 configurations. Each configuration has been evaluated with two different sets of heat schema parameters similar to the Gdansk site. The five different pairs of energy price applied at the previous Gdansk case have been applied and investigated for the Trzebinia site as well. The NPVs are below or above the horizontal axis for this site. It means that the profitability of the investment is not univocal and strongly depends on the costs, the energy prices and live steam thermodynamic parameters. So, for a site with lower energy demand like Trzebinia, it seems that the HTR is not the only and best option. In case of higher energy prices, high thermodynamic parameters applied and long term governmental subsidy, the investment could be worth for realization (zero or positive NPV) but still represents high risks due to the wide spread of NPV values in the parameter study. Only the cases with higher thermodynamic parameters seem to be economically viable. If the HTRs operate with higher thermodynamic parameters then the NPV values are higher with 288÷2000 M€. The higher the energy prices the bigger the NPV increment. It means that the planed HTRs should work on as high thermodynamic parameters as possible (its effect on the construction cost has not been investigated due to lack of data on prices of different structural materials) to increase the released electrical energy which generates extra revenue after sold electricity on the grid similar to the Gdansk site. So, this last conclusion seems to be general. The results got with the fifth pair of prices show lower NPV values compared to the results got with the fourth, but it is more realistic and closer to the real case. Here, the NPV values are very low and close to 0 which can moderately be attractive for potential investors. The reason for the low NPVs in case of the fifth pair of price is that the spare energy sold through the grid adds limited value to the NPV while the costs increase significantly towards the bigger configurations (bigger nominal capacity).

Last but not least, two specific concepts were investigated to improve the economics of a twin HTR unit site. The first one is about a dynamic rate change between released thermal and electrical power depending on the current electricity price on the market. The second concept aims to store the energy produced by the twin HTR unit when the energy demand falls down and the electricity is cheap.

It was found that the impact of the idea to increase the NPV by the dynamic energy type change run is very marginal. It is worth to mention that the construction and the O&M costs of the gas fired boiler which can substitute the twin HTR unit has not been considered yet. Only the price of used amount of gas fuel has been taken into consideration in the economical calculation. If one considered these above mentioned costs (which occur in the reality) then the reference value of NPV of that dynamic energy type change run scenario would be worse than the current value and that of the normal run which was used as reference for comparison purpose.

The second specific scenario is based on the idea to store the spare energy (mainly electricity during periods with low electricity price) into energy storage chemicals (for e.g.: hydrogen or methanol) instead of releasing to the grid. After the disappointing result of the first specific scenario, this second one did not reach the phase of coupled heat schema – economic calculations due to reasonable considerations.

5 A European HTR in support of a South African CTL Plant

This chapter is a contribution of NWU to Deliverable D4.41

5.1 Introduction

The objective of WP4, as stated in the NC2I proposal to the European Commission, is that "WP4 will investigate the economic, business, market, financial aspects of nuclear cogeneration. It will provide the R&D community for nuclear cogeneration with a market focused vision towards the demonstrator by specifying the general parameters of a demonstrator and road mapping the research towards it. This will accelerate the NC2I demonstration program and streamline the deployment of nuclear cogeneration in Europe. Deployment scenarios following this demonstrator will be elaborated and their impacts evaluated. Based on the previous links made by EUROPAIRS, an End-User Group structuring industrial companies and associations interested in nuclear cogeneration will be set up and managed as a key forum interact with NC2I."

North West University was invited by the European HTR-team to submit a RSA proposal to participate in NC2I's WP4 as follow-up of the work that we did for project ARCHER. This was done. NWU succeeded to obtain 80% co-funding from the South Africa Government's under the ESASTAP program. We hereby express our gratitude to the Department of Science and Technology for their support in this regard.

The objective of South Africa's participation in NC2I is much the same as stated in the NC2I proposal to the European commission for WP4, save that we specifically focused on two potential applications of nuclear co-generation in South Africa, namely in support of a Coal-to-Liquid and a Gas-to-Liquid process. Both these technologies are of strategic importance to South Africa. Coal because the country has vast coal resources, and gas because it is expected that the country may have huge shale gas resources.

The work reported in this document is based on extensive process modelling to determine mass and energy balances for the two focus areas. Process modelling outputs served as input to an integrated economic feasibility model, designed from first principles and aimed at the quantification of two key performance indices set for the application of nuclear co-generation in South Africa.

5.2 CTL plant modeling

5.2.1 Mass and energy balances

Most of the work presented in this section was done under project ARCHER. (Stoker PW, 2014). For convenience and later reference, extracts of the study is included herewith:

"The Sasol Synfuels operation in Secunda, Mpumalanga was used as the basis for developing a base case scenario, as this is the only industrial scale Fischer-Tropsch (FT) coal-to-liquid plant currently in operation. Although open literature on the Secunda operations is limited, appropriate assumptions were made in the simulation to ensure the results and operating conditions are logical and confirmable where possible. A typical coal to liquids processing plant was simulated with the help of a process simulator Aspen Plus. The process model included a coal preparation section, an air separation, steam and electricity generation as well as a steam methane reforming sections. The simulation also included a fixed bed coal gasification, Rectisol gas clean-up and Fischer-Tropsch hydrocarbon synthesis section. The Soave-Redlich-Kwong (SRK) equation of stage with Kabadi-Danner (KD) modifications for water-hydrocarbons systems was used as property package for the base case simulation. A typical Mpumalanga -Highveld coal with an ash content of 30% was chosen as feedstock for the gasification and steam boiler simulation. Anderson-Schulz-Flory distribution was assumed to provide a sensible product spectrum for the Fischer-Tropsch reactors. For the FT reactor the Anderson-Schulz-Flory α-value is usually limited to <0.71, with 0.67 a standard modelling value for High Temperature Fischer-Tropsch (HTFT) with fused-Fe catalyst. The simulation results showed good correlation against process information that was available in published data."

"Since the nature of the coal-to-liquid plant is that of a continuous process (for example the supply of utilities such as steam, electricity, or input commodities such as coal, natural gas; or intermediate process streams such as H2, CO, etc.) it was imperative that an overall mass balance be established as input to the economic feasibility model. This was achieved in terms of a mass flow rate balance in tons/hour. The annual input cost of a commodity stream can then be calculated as (cost/ton)*(ton/h)*(h/year). Equally, the annual income associated with a process stream can be calculated as (price/ton)*(ton/h)*(h/year)."

Energy balance of the coal to liquid process was a challenge due to complexity and the lack of "inside" data. A top down allocation process was used in the case of electrical power. The energy balances of steam and process streams were not considered. These areas will require more detailed analysis in the future.

5.2.2 Economic feasibility

Project ARCHER called for the identification of Key Performance Indices (KPI) relating to the application of nuclear co-generation technology to industrial processes. The South African team approached this task by interviewing previously employed senior executives of the Sasol organization. These interviews revealed that the petrochemical industry will not consider investing in a new project unless its real post tax Internal Rate of Return (IRR) is above 6%.

Internal rate of return (IRR) is a cash flow based investment performance metric which, if applied correctly, accounts for practically every dimension of a technology solution over its life cycle and sometimes even beyond. Hence it was decided to use IRR=6% as an investment hurdle rate in the economic analyses.

Interviews further revealed that reduction in CO2 of the CTL process is key to the implementation of any future technology. A target of 40% reduction in current CO2 emission was consequently defined as a second KPI.

A comprehensive economic feasibility model was subsequently compiled with the functionality to trace utility and process streams throughout the CTL plant. The latter was modelled as a sequence of business units.

"A crucial step in the development of the economic feasibility model was the identification and demarcation of various business units which, when combined, would represent the operations of the plant as a whole. The approach followed was to identify the physical battery limits of plant units. Input streams to and output streams from these units were then determined. Engineering judgment was subsequently used to eliminate those input/output streams which were deemed to have minor cost implications for the study, when compared to main process streams. An example of such a minor input/output stream was instrument air."

The economic model applies the IRR hurdle rate principle to each business unit: Any one business unit "buys" utility and process stream inputs from others, somehow adds value them, and "sells" an output stream (or steams) to a next business unit. Selling price is determined such that the business unit delivers a real IRR equal to the hurdle rate. Since many of these financial transactions are internal, one would expect that, if they are consolidated, it would yield the IRR of the business when viewed "from the outside", meaning the IRR of the CTL plant as a whole -

buying coal, electricity, etc. and selling hydrocarbon fuels and chemicals. The model incorporates a consolidation module, serving to verify that all internal transactions have been accounted for.

Using the business unit approach as elaborated above has the advantage that a price can be determined for each internal process and utility stream. This in turn facilitates economic analysis of "plug-and-play" alternatives. It is now possible for example, to compare the cost of buying nuclear steam with the price of steam generated by coal steam boilers in the current CTL plant.

5.2.3 Model validation

"Model validation is a difficult problem. In the final analysis an economic feasibility model can only be validated against the actual financial performance of the plant which the model endeavors to predict. This objective was achieved to some extent in the case of the coal to liquid business, since it is in operation in South Africa. Limited data is available in public domain documents such as overviews of investment analysts and the Integrated Annual Report of the Sasol Group. Both these sources were used to achieve at least a measure of validation."

Where financial performance data were not available from real life plants or approximately similar real life plants, it was not possible to validate the output of the economic feasibility model. Since the quality of output data depends on the quality of input data, input data to the model was carefully assessed using engineering judgment and reference to real life realities.

5.2.4 Modeling scenarios

This section discusses 5 modeling scenarios:

- Reference scenario. Secunda West Plant as is (2012)
- Nuclear hydrogen in support of CTL
- Scenario 1. Replace coal generated steam and electricity with the same from Nuclear Co-gen
- Scenario 2. Replace Steam Methane Reforming (SMR) with Plasma Arc Reforming (PAR). Dry reform CH_4
- Scenario 3. Replace SMR with PAR; Wet reform CH_4.

Results and conclusions regarding study scenarios 1-3 are presented in section 4.

5.2.4.1 Reference scenario. Secunda West Plant (SWP) as is (2012)

The theme of this scenario is the existing SASOL coal-to-liquid process at Secunda. A high level, simplified schematic of SASOL's Coal to Liquid process is shown in Figure 1, taken from a provisional patent filed by NWU. It exhibits nomenclature for various process streams. Component and stream numbers identified in **Figure 48** will be referred to later on in the analyses and discussion of simulation results.

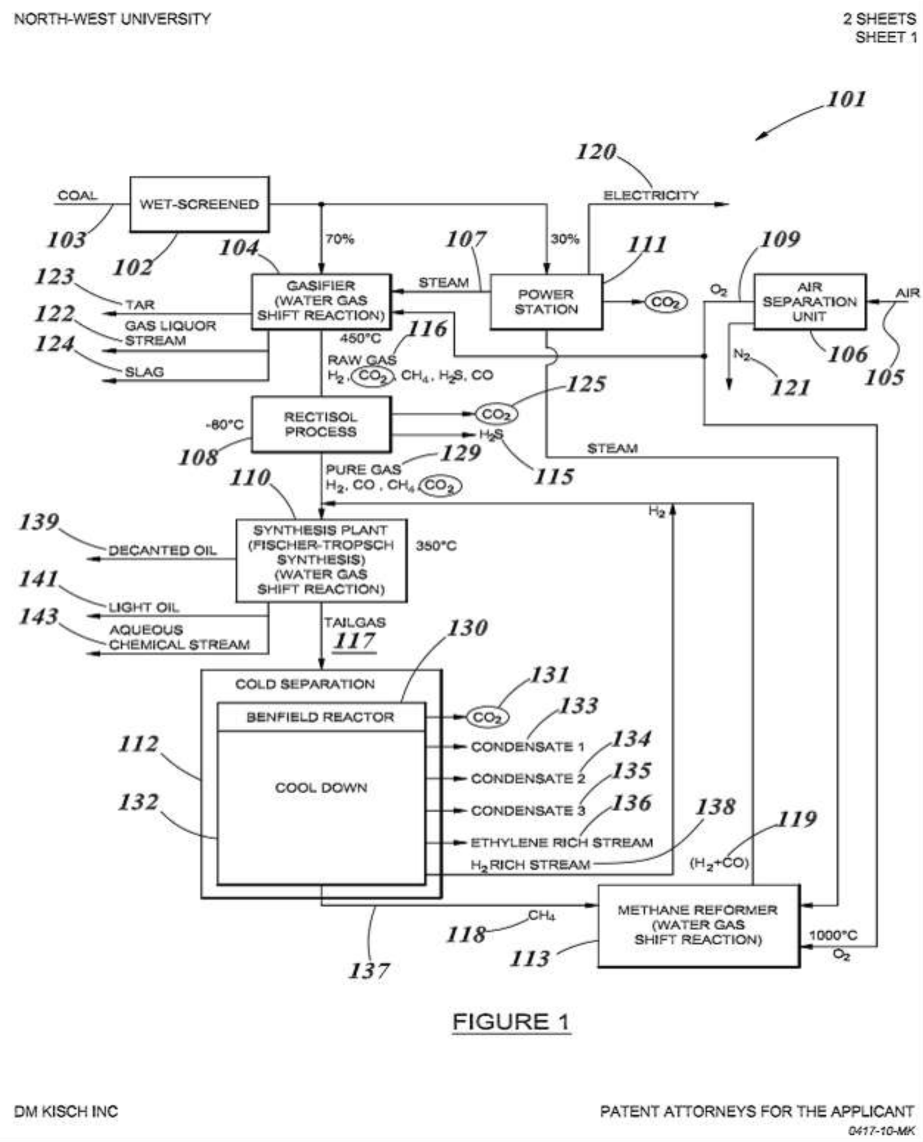


Figure 48 - Simplified CTL process

Secunda site accommodates two identical 80,000 barrel/day syncrude plants. The West Plant was chosen as the reference scenario, hereinafter referred to as SWP.

The ARCHER report elaborates on the model itself, its validation against publicly available product sales (tons produced and associated income) and key findings in respect of economic feasibility. These results will not be repeated here.

For the purpose of the NC2I study it was necessary to extract from the model internal utility and process stream sales data (in Euro). This data is used in subsequent discussions to argue the economic feasibility (or non-feasibility as the case may be) of alternative (nuclear supported) plant configurations.

Construction of the SWP was completed in the in the period 1980-1983, at a reported investment of 2.3 billion Rand (1976) http://www.sasol.co.za/about-sasol/company-profile/historical-milestones. Rand dollar exchange rate during this time was about R1.40/USD. Hence the CTL investment in dollar terms amounted to $1.64 billion ($1.64x10^9 for a 160,000 barrel/day facility). SWP has long been paid off, whereas the numbers reported in subsequent tables are for a 80,000 barrel per day plant to be constructed in 2012 at a total cost of R120 billion (15 billion USD at R8/USD). This represents an annual escalation of construction cost over a 36 year period equal to 8.4% (in USD). This number is way above dollar inflation rates over the period and reflects real cost escalation of complex construction projects due to enhanced safety requirements, much more stringent environmental pollution requirements, higher quality standards imposed on end products and most important, the very competitive price that Sasol was able to negotiate at the time, due to a worldwide decline in major construction projects.

Table 17 shows utility prices for steam, oxygen and electricity. Please remember that these prices were determined such that the business unit which sells the utility achieves a 6% real post tax IRR. It follows that these prices include a profit margin. Note the very low price of “input” coal: 0.91€/GJ (or approximately 3.3€/MWh.) There are two reasons for this: Sasol mines its own coal and can thus set the transfer price to the CLT plant. The price was determined from Synfuels’ income statement as per Sasol’s Annual Integrated Report, 2012. Furthermore the coal has a high ash content and is therefore considered of low quality.

Utility selling prices*			
	R/ton	€/ton	€/GJ**
Steam (107)	170	16.7	5.00
Oxygen (109)	598	58.6	-
	R/MWh	€/MWh	€/GJ
Electricity (own generation,120)	584	57.3	15.9
Electricity (Eskom)	450	44.1	12.3
*Input costs	R/ton	€/ton	€/GJ
cost of coal (103)	211	20.10	0.91
cost of demin water	33.1	3.15	-
**40bar, 450C	3330	KJ/kg	

Table 17: Utility prices, reference scenario with steam-to-electricity efficiency = 43%; 2012 Rand value; R10.5/€

Please note that for the NC2I study, steam conversion to electricity was set at 43%. The ARCHER study set this number at 25%, based on the fact that SWP at the time utilized small generators (approximately 50MW) that are relatively old and is hence rather inefficient. Although this assumption may be accurate when considering replacement of such old technology with an alternative (for example outsourced nuclear electricity) it is not appropriate when one erects a new plant, as considered here. Hence the efficiency was adjusted to 43%, resulting in a reduction in selling price of own generated electricity from R830/MWh to R584/MWh. (Divide by 10.5 to convert to Euro.)

Eskom’s price for electricity is an estimate for what it might have cost SASOL in 2012. Bulk electricity supply to large consumers is negotiated between the parties. Regrettably it is not public knowledge. What is certain is that Eskom’s 2012 prices were not cost reflective. This resulted in annual increases in electricity price in the order of 25% over the past 4 years. It is reported for example by www.nstf.co.za/ShowProperty?nodePath=/.../NSTF/.../EskomMacColl...for that primary energy cost increased by 36.1% from 20.6 RSAc/kWh as at March 2012 to 28.1 RSAc/kWh at 31 March 2013.

www.moneyweb.co.za/archive/eskom-plays-russian-roulette-with-power claims that “Eskom buys electricity at about 90c/kWh” through Power Purchase Agreements (PPAs) with various companies including Sasol. (Since 2012 Sasol has installed gas fired power capacity sufficient to meet its own needs and also sell power to the grid.) A reliable source (E, 2015) reports that “The price currently being paid for (PPA) power is between 52 RSAc/kWh and 88 RSAc/kWh”. The author further notes that short term power purchases’ “pricing cap is currently ~ 94.6 c/kWh”. Note that Eskom buys only a small percentage of its electricity through PPAs. The bulk of its generation capacity is derived from coal fired stations. At the PPA prices for delivery onto the grid as reported here, it is likely that Eskom cross subsidizes PPA prices.

It follows that the estimated internal selling price of Sasol's "own generated electricity" (58.4c/kWh) is well within the PPA price range.

Table 18 shows prices of commodity streams 129, 119 and Sasol Advanced Syntheses (SAS) feed, as calculated by the CTL model, using utilities at the prices indicated in **Table 18**.

Process stream selling prices. Reference scenario: SWP; 43% steam-to-electricity eff.													
Process stream identification and %	Process stream species (ton/h)							€/ton	€/GJ	Allocated to species (in €/GJ)*			
	H2	CO	CH4	C2H6	CO2	other	LHV	(R10.5/€)		H2	CO	CH4	C2H6
	120.1	10.2	49.9	47.2	0	0	MJ/Kg						
Pure gas (129)	74.2	653.9	137.6	6.2	28.8	0.12	25.2	133.1	5.27	2.07	1.55	1.59	0.07
%	8.2%	72.6%	15.3%	0.7%	3.2%	0.0%							
SMR (H2+CO) (119)	42.6	190.6	23.7	0	91.4	295.3	12.8	107.5	8.39	5.21	1.98	1.20	-
%	6.6%	29.6%	3.7%	0.0%	14.2%	45.9%							
SAS feed stream (129+119)	116.8	844.5	161.3	6.2	120.2	295.4	20.1	116.9	5.83	2.64	1.62	1.51	0.06
%	7.6%	54.7%	10.4%	0.4%	7.8%	19.1%							
										(€/GJ)(GJ/ton)/1000=€/Kg			

Table 18: Syncrude process stream selling prices

Note that the model calculates a price for the syncrude process steam. This price was allocated to energy carrying species on the basis of their respective Lower Heat Values (LHV) and are shown in €/GJ. Observe that stream 119 contains approximately 45% water (grouped under "other"), causing its LHV to be about half that of stream 129. CH4 recovered by cold separation (137) is partly sold as heating fuel (35.7 ton/h) and partly reformed (118 at 166 ton/h). In both instances CH4 is sold at R3000/ton (375 $/ton; 7.51$/GJ; 5.78€/GJ). Note the average price of CTL hydrogen: 2.64 €/GJ.

The post-tax real IRR of the reference CTL facility, calculated over a 40 year period, is 9%. Income was estimated for an array of sellable end products, and correlated with data reported in Sasol's (audited) Integrated Annual Report (Synfuels division) 2012, in terms of tonnage and revenues as follows:

- Refined products (tar, LPG, petrol, jet and diesel fuel, and propylene)
- Heating fuel (CH4)
- Gasification products (Phenol, NH3)
- Alcohols and keytones
- Chemical feedstocks including ethylene

Before discussing the opportunity for nuclear hydrogen in support of CTL, a few comments are made regarding practicalities of CTL plants. These subtleties were not modelled:

- CTL plants are subject to a statuary shutdown once in a two year period. Such an outage takes typically 2 weeks.
- An 80,000 bpd plant comprises many similar units operating in parallel. For example 40 gasifiers, 8 synthesis plants, etc. There are 2 bottlenecks: only two trains for Rectisol and 2 for cold separation. A 50% loss in production is to be expected if one of these trains is down. Availability of these modules are high – typically 98%.
- Many parallel modules provide ample opportunity for managing normal maintenance outages in such a way that plant output is not unduly compromised.

- "emergency situations" that would cause a CTL plant to shut down are very rare. As far as the author was able to ascertain it happened on only 2 occasions in the 35 years of SWP operations.
- Regarding hazards brought by the CTL plant, normal hazard and emergency procedures for NH3 and LPG applies. The current study did not investigate this issue. It will obviously come into the picture during a feasibility study, and the latter will only be entered into if the initial framing of the NCTL project shows economic merit.

5.2.4.2 Nuclear hydrogen in support of CTL

As part of WP4, and following through on the recommendations for further investigation put forward in the ARCHER work (Stoker PW, 2014), an in depth investigation was carried out to determine the economic feasibility of introducing nuclear energy into a CTL process using hydrogen as energy carrier.

The study and its findings were reported at the ICAPP 2015 conference in France (Stoker PW, 2015), and are summarized here for convenience:

The aim of the study being an investigation into futuristic CTL processes, two scenarios were of particular interest:

"**Co-gasification**, where gasification was partly achieved by Lurgi-gasifiers and partly by CO2 blown entrained flow coal Shell gasifiers. In contrast to Lurgi gasifiers, which with the help of the water-gas shift and complex devolatilization reactions generate a hydrogen rich syngas (with a high CO2 penalty), Shell gasifiers produce CO2 lean syngas, but with low hydrogen content. The rationale for introducing the Shell gasification process was to not produce CO2 in the first place, and supplement hydrogen shortfall with nuclear hydrogen. Moreover by Using CO2 as carrier gas in the Shell gasifiers, carbon recirculation aided in the mitigation of overall CO2 emissions" and

"**CO2 lean gasification**, where all Lurgi-gasifiers were replaced with Shell gasifiers."

In both scenarios oxygen was outsourced (since it is readily available as a by-product of hydrogen production) and conventional Steam Methane Reforming (SMR) was replaced by Plasma Arc Reforming (PAR).

A Nuclear supported Hybrid Sulphate (NHyS -an electrochemical process) was used to produce hydrogen. The paper reports a projection of hydrogen selling to the CTL facility that would make the NHyS facility economically viable as a function of the overnight cost of the nuclear plant and HyS plant (200 and 250 M$/Kg/sec hydrogen). Refer to **Figure 49**.

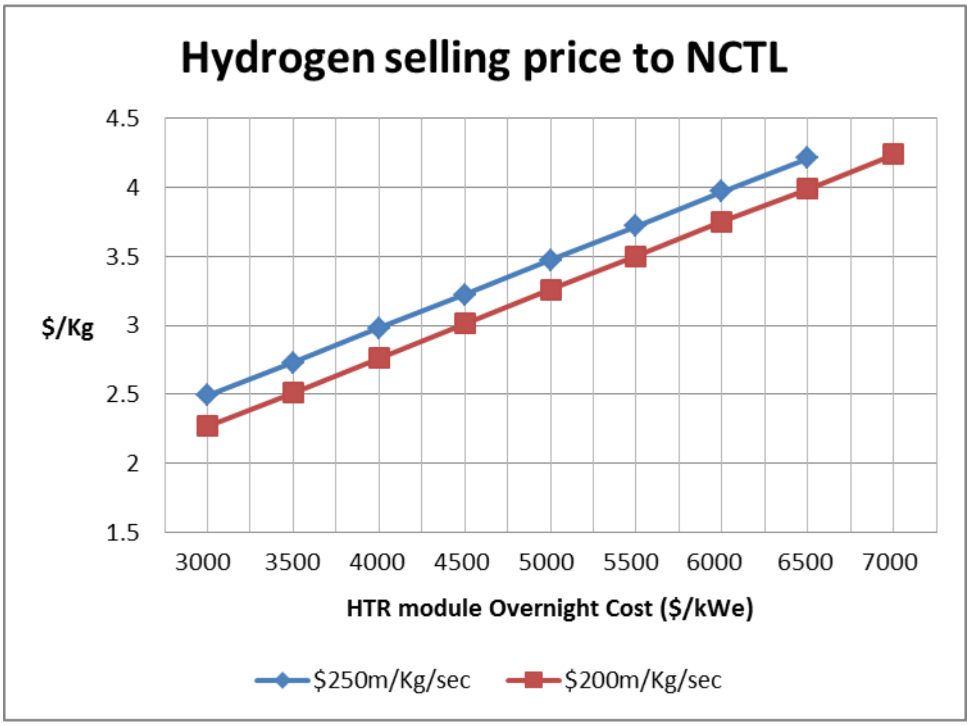


Figure 49 - Nuclear selling price as a function of overnight cost of the nuclear and HyS plants. Energy Conversion: MWe=40%*MWth. 30% of nuclear energy converted to electricity.

It follows from **Figure 49** that the "best" price for nuclear hydrogen is 2.25$/Kg (14.3 €/GJ) and the "worst" 4.25$/Kg (27€/GJ). Compare these numbers with the price of hydrogen from the CLT process (2.64€/GJ). Nuclear hydrogen is 5.4-10 times more expensive than when the commodity is produced by the water gas shift reaction in a conventional CTL plant. The study reports the following conclusions:

- "A HTR plant delivering heat to a HyS plant at 650°C has such a low hydrogen output that it was not considered in this study.
- Although the capital intensity (overnight cost per barrel per hour) of a conventional CTL plant can be reduced from $6.8m/bbl/h to $2.1m/bbl/h if nuclear hydrogen was available, this advantage is cancelled by the increase in capital intensity of the combined CTL/HTR/HyS system, to values far beyond that of a conventional CTL plant. As a consequence it was necessary to increase the selling price of synthesized products (by assuming a higher crude oil price) to make these configurations economically viable.
- A HTR plant with temperature top-up to deliver heat to a HyS plant at 800°C, producing 1.46 kg/sec hydrogen in support of a CTL process, has a small economic viability window, even at oil prices in excess of 150$/barrel. Hence it is not worth pursuing.
- A VHTR plant capable of delivering heat to a HyS plant at 950°C, producing 2.2 kg/sec hydrogen in support of a CTL process, has a reasonable economic viability window when the oil price is above $150/bbl.
- A higher oil price will obviously also cause an increase in the profit margin of a conventional CTL plant. This fact, combined with the increase in capital intensity of a CTL/HTR/HyS solution, makes the introduction of nuclear energy into the CTL process through the nuclear hydrogen path an unlikely future technology.
- Nuclear hydrogen is uncompetitive when compared to the cost of hydrogen production through the water-gas-shift reaction as is currently done in Sasol's CTL process. Future NCTL research should therefore focus on reducing the CO2 footprint of the CTL process through means other than using HyS hydrogen as energy carrier."

In lieu of the last conclusion, the following scenarios were investigated and are reported in this report:

5.2.4.3 Scenario 1. Replace coal steam and electricity with the same from Nuclear Co-gen

Coal used in the Sasol process is quite brittle, leading to approximately 33% of mined coal to break into fines. These fines can't be fed into the Lurgi gasifiers and must therefore either be burned to generate steam or sold to nearby Eskom coal power stations. Consequently, replacing coal steam with nuclear steam has the effect of transferring CO_2 emission to another entity. Hence it was not appropriate to acknowledge CO_2 reduction in the financial modelling effort. Instead coal fines were sold at 50% markup on purchase price

Scenario 1 requires an annual steam supply of 18.35 million ton (40 bar, 450C). Steam is utilized in the process and not returned to the nuclear facility. The plant also requires 5694 GWh electrical energy per annum.

In this scenario power station 111 (comprising steam boilers and generator units) is removed, thereby reducing CTL plant overnight cost by bR20.4 ($2.55 billion, €1.94 billion) and electricity need to 634MW. These utilities must be supplied by nuclear co-generation as follows:

- % of nuclear steam converted to electricity: 43.2%. (See section 3.2)
- Number of reactor pairs required (assuming 85% availability per pair): 8.45
- Hence this scenario requires 16 or 18 reactors depending on the availability assumption

5.2.4.4 Scenario 2. Replace Steam Methane Reforming (SMR) with Plasma Arc Reforming (PAR). Dry reform CH4

Scenario 2 builds on scenario 1 by:

- Replacing Steam Methane Reforming 113 with Plasma Arc Reforming.
- Partly reform CO_2 (stream 125) recovered by Rectisol (unit 108) using methane produced by the CTL process (stream 118). ($CH_4 + CO_2 = 2H_2 + 2CO$)
- Adjust the H_2/CO ratio with the water gas shift reaction to achieve $H_2/CO=2$ (mol/mol) ratio at the input of syntheses plant 110. ($CO + H_2O = 3H_2 + CO_2$)

Figure 50 shows a simplified process flow diagram for scenario 2. Two sub-scenarios are of interest:

- The same amount of CH_4 as reformed by SMR in scenario 1 is now reformed by PAR, with the balance sold as heating fuel. (Scenario 2a)
- All available CH_4 is reformed. (Scenario 2b)

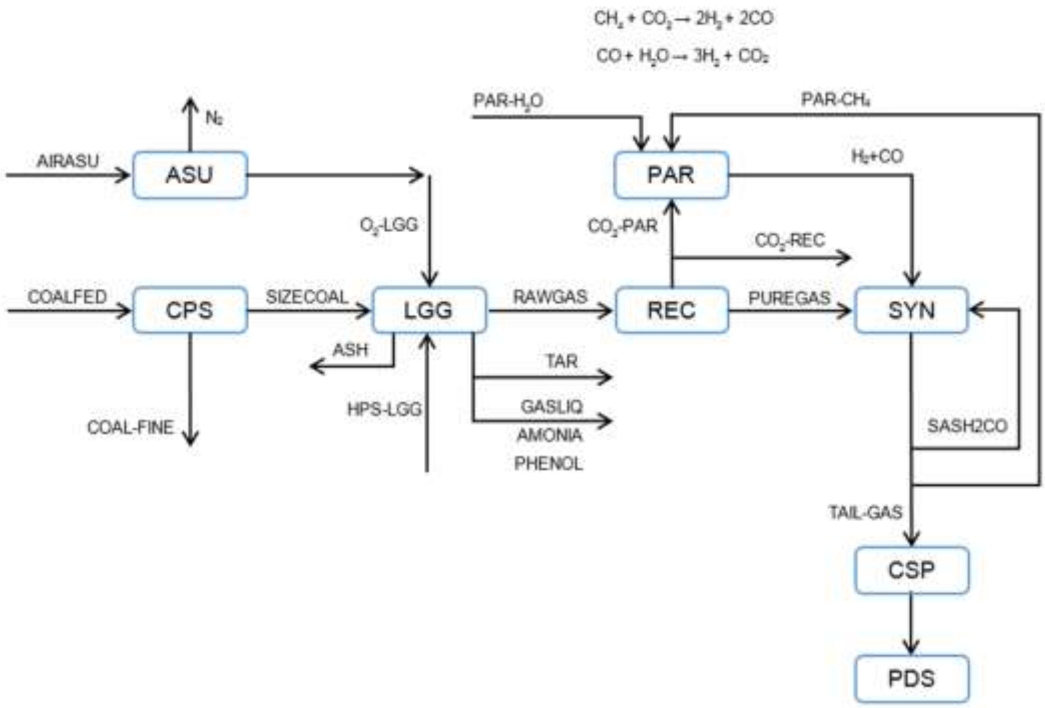


Figure 50 - Simplified process flow diagram for Scenario 2

5.2.4.5 Scenario 3: Replace SMR with PAR; Wet reform CH4.

Scenario 3 builds on scenario 1 by:

- Replacing Steam Methane Reforming 113 with Plasma Arc Reforming
- “Wet” reform CH4 using methane produced by the CTL process (stream 118). (CH4+H2O = 3H2+CO)
- Live with CO2 emission recovered by Rectisol (unit 108)

The rationale behind this scenario is to eliminate CO2 produced by conventional SMR using PAR fired with nuclear electricity. **Figure 51** shows a simplified process flow diagram for scenario 3. As before, two sub-scenarios are of interest:

- The same amount of CH4 as reformed by SMR in scenario 1 is now reformed by PAR, with the balance sold as heating fuel. (Scenario 3a)
- All available CH4 is reformed. (Scenario 3b)

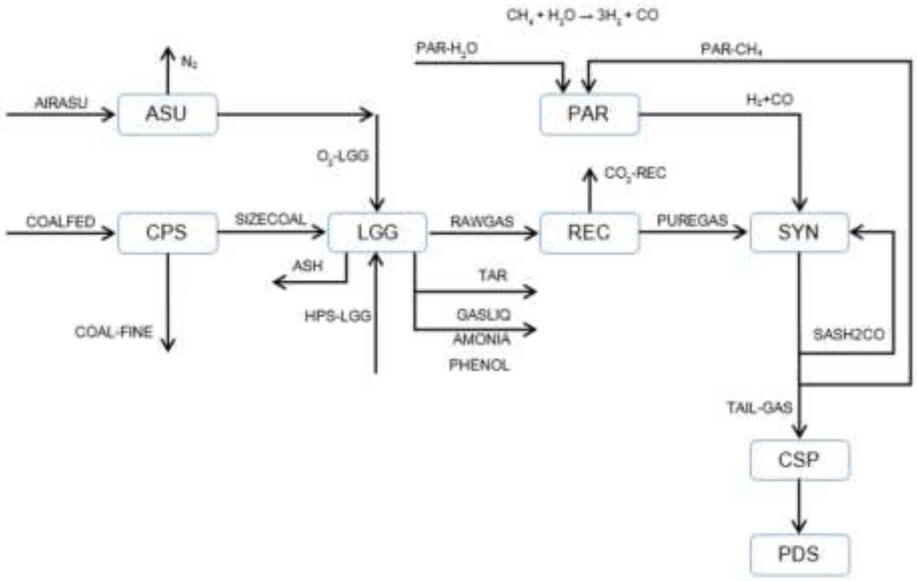


Figure 51 - Simplified process flow diagram, Scenario 3

5.3 Nuclear co-generation modeling

5.3.1 Modeling approach and verification against NC2I economic model

To ensure that the economic feasibility work carried out by the South African team is aligned with the same done by the European team, it was decided to calculate the NPV of the NC2I "reference scenario", using the South African economic model. The South African model follows a different philosophy as follows:

Economic analysis is carried out in an assumed inflation free environment. Price/cost increases over time is only allowed if such

- is expected to increase in **real terms**;
- can be motivated on rational grounds;
- is expected to stabilize at a future time as a consequence of free market forces.

The NC2I model incorporates inflation. Consequently, for the comparison study, all inflation parameters were set to zero in the NC2I model.

The South African model does not rely on NPV as an investment decision criterion. Instead it calculates an investment's Internal Rate of Return (IRR). It is argued that this metric is in real terms, since inflation is not included in any input data. Corporate taxation is included in the model. So is an investment incentive in the form of accelerated amortization of plant and equipment for taxation purposes. To enable comparison with the NC2I model, the South African model was expanded to include a NPV calculation with a user specifiable discount rate. Taxation rate was set to 20% and amortization period to 15 years (straight line), identical to the assumptions made for NC2I's reference scenario.

South African modelling philosophy calls for a user specified target IRR (called a hurdle rate). It then iterates the selling price of nuclear heat (and electricity) to yield an IRR equal to the hurdle IRR. This "output price" is subsequently fed into the CTL model as an "outsourced utility". To facilitate comparison with the NC2I model, a provision was made to "skip" the iteration scheme and use specified heat and electricity output at their respective selling prices instead. It is noted that in the South African model, the nuclear module is fully integrated with the CTL model, which enables coupled system economic analyses.

Finally a flag was programed into the SA nuclear module to receive all input data in Euros.

Other input data called for by the NC2I model is similarly needed in the South African model. **Table 19** shows the detail.

Parameter	**Value**	**Units**
Plant availability	85%	-
Nuclear Fuel	27.1	M€/year
Maintenance & operations	23.4	M€/year
Plant decommissioning	2.9	M€/year for 40 years
Plant economic life	40	Years
Energy output rate (steam)	387.63	MWth
Energy output rate (electricity)	98.25	MWe
Selling price (steam)	40	€/MWthh
Selling price (electricity)	50	€/MWeh

Table 19: Common input data used for comparison

With the above assumptions both models calculated NPV at 8% equal to -1M€. We therefore conclude that the RSA model gives consistent results, serving to validate the codes of both models.

5.3.2 Adaptations to meet CTL requirements and South African conditions

An energy balance over the NC2I nuclear reference scenario revealed the following:

Nuclear energy in: 2x250MW = 500MWth

Steam energy is sold at a rate of 387.63 MWth. Part of this supply is low pressure steam. It was assumed that steam will be condensed in the industrial facility and returned as demineralized water. Electricity is sold at a rate of 98.25 MWe. It follows that only 14.12 MW (2.8%) is not sold, but used in the plant to power blowers, pumps, etc., and also provide for heat exchanger losses, pipe losses and the like.

In the CTL application steam is used in the process and not returned. Furthermore, steam used to generate electricity will have to be condensed by the nuclear plant. Cooling towers (preferably dry, since water is a very scarce commodity in South Africa) must therefore be provided.

Modelling parameters for the NC2I nuclear facility were adapted as follow:

Nuclear energy available in the form of high pressure steam 95%*500MW = 475MW

Percentage of steam converted to electricity is scenario dependent. Assume it is x%. It follows that:

- Steam supply to the CTL facility = 475*(1-x%);
- Steam supply converted to electricity and supplied to the CTL facility = (475*x%*43% - 5), where steam energy is converted to electrical energy at an overall efficiency of 43%, and the plant itself uses 5MW electrical energy.
- The plant's steam loop is replenished with demineralized water at the rate at which steam is supplied to the CTL facility.
- Steam converted to electricity is condensed at the nuclear plant and returned to the nuclear plant's steam loop.
- Line losses associated with transport of steam to the CTL facility are ignored.

Nuclear fuel, O&M and decommissioning costs shown in table 3 were retained. Plant overnight cost was set at 930.8M€ expended equally over 4 construction years. Economic life was taken as 40 years. Steam price was set at 80% of electricity price. Tax rate was set at 28% and plant amortization for tax purposes was taken as 5 years.

5.4 Results and discussion

5.4.1 Scenario 1

Assuming availability of the nuclear plant at 80%, setting a 6% IRR hurdle rate and using the electricity/steam production ratio calculated in section 2.4.3, the model estimated the cost to the CTL facility of nuclear generated steam and electricity in the South African scenario as shown in **Table 20**. At 80% availability the CLT facility would need 18 nuclear reactors of 250MWth. The overnight cost of a two reactor nuclear module was taken a 930.8M€. No provision was made for the economy of scale that should result from constructing 9 such modules on a single site.

Nuclear plant selling prices			
	R/ton	€/ton	€/GJ**
Nuclear steam	443	43.4	13.04
Oxygen (109)	725	71.1	-
	R/MWh	€/MWh	€/GJ
Nuclear Co-gen electricity	798	78.2	21.7
Electricity (Eskom)	-	-	-
**40bar, 450C	3330	KJ/kg	

Table 20: Utility costs to the CTL facility. Scenario 1. Nuclear plant availability = 80%

Nuclear electricity is about 37% more expensive than "own generated" electricity from coal, causing cost of oxygen to increase by 21%. This increase was expected, since Air Separation Unit 106 consumes about 50% of the CTL plant's electricity.

Nuclear steam is a whopping 161% more expensive than "own generated" steam from coal, resulting in a knock-on increase of selling prices of process streams as shown in **Table 21**

.

Process stream selling prices. Scenario 1.													
Process stream identification	Process stream species (ton/h)							€/ton	€/GJ	Allocated to species (in €/GJ)*			
and %	H2	CO	CH4	C2H6	CO2	other	LHV	(R10.5/€)		H2	CO	CH4	C2H6
	120.1	10.2	49.9	47.2	0	0	MJ/Kg						
Pure gas (129)	74.2	653.9	137.6	6.2	28.8	0.12	25.2	194.3	7.70	3.02	2.26	2.32	0.10
%	8.2%	72.6%	15.3%	0.7%	3.2%	0.0%							
SMR (H2+CO) (119)	42.6	190.6	23.7	0	91.4	295.3	12.8	125.1	9.77	6.06	2.30	1.40	-
%	6.6%	29.6%	3.7%	0.0%	14.2%	45.9%							
SAS feed stream (129+119)	116.8	844.5	161.3	6.2	120.2	295.4	20.1	150.6	7.51	3.40	2.09	1.95	0.07
%	7.6%	54.7%	10.4%	0.4%	7.8%	19.1%							
										(€/GJ)(GJ/ton)/1000=€/Kg			

Table 21: Process stream selling prices. Scenario 1. Nuclear plant availability = 80%

Hydrogen, for example, now sells at 3.4€/GJ, up 29% from the reference scenario, but still 4.2 times cheaper than the “best” price for nuclear hydrogen (14.3€/GJ).

The 40 year real post tax IRR of the CTL plant for this scenario is 4.3%, which is below the hurdle rate. It is not a convincing investment opportunity. Note that the IRR of the CTL facility fell 4.7% from the reference case’s 9%.

Repeating the above calculations with 90% availability (16 reactors), gave the following results:

Nuclear plant selling prices			
	R/ton	€/ton	€/GJ**
Nuclear steam	394	38.6	11.60
Oxygen (109)	680	66.7	-
	R/MWh	€/MWh	€/GJ
Nuclear Co-gen electricity	710	69.6	19.3
Electricity (Eskom)	-	-	-
**40bar, 450C	3330	KJ/kg	

Table 22: Utility costs to the CTL facility. Scenario 1. Nuclear plant availability = 90%

Process stream selling prices. Scenario 1.													
Process stream identification	Process stream species (ton/h)							€/ton	€/GJ	Allocated to species (in €/GJ)*			
and %	H2	CO	CH4	C2H6	CO2	other	LHV	(R10.5/€)		H2	CO	CH4	C2H6
	120.1	10.2	49.9	47.2	0	0	MJ/Kg						
Pure gas (129)	74.2	653.9	137.6	6.2	28.8	0.12	25.2	182.3	7.22	2.83	2.12	2.18	0.09
%	8.2%	72.6%	15.3%	0.7%	3.2%	0.0%							
SMR (H2+CO) (119)	42.6	190.6	23.7	0	91.4	295.3	12.8	121.4	9.48	5.88	2.23	1.36	-
%	6.6%	29.6%	3.7%	0.0%	14.2%	45.9%							
SAS feed stream (129+119)	116.8	844.5	161.3	6.2	120.2	295.4	20.1	143.8	7.17	3.25	1.99	1.86	0.07
%	7.6%	54.7%	10.4%	0.4%	7.8%	19.1%							
										(€/GJ)(GJ/ton)/1000=€/Kg			

Table 23: Process stream selling prices. Scenario 1. Nuclear plant availability = 90%

The 40 year real post tax IRR of the CTL plant for this scenario is 5.9%, representing a marginal investment opportunity. However, note that CTL IRR is down 3.1% when compared to the reference case.

Carbon taxation is currently under consideration in South Africa, based on equivalent CO2 emission. A penalty of R120/ton CO2 is proposed, increasing with 10% per year for 5 years. Furthermore, a 60% “basic tax free threshold” is allowed, which has the effect that carbon tax on CO2 emission will be R48/ton (4.6€/ton). The reference scenario was run with this taxation penalty included. It yielded an IRR=7.8% (down from 9%). In this scenario 1, only CO2 emitted by the steam boilers is eliminated (accounting for approximately 50% of SWP’s total annual emission of 29.1 million ton). Imposing the tax penalty on remaining CO2 yielded an IRR=8.4%. Clearly, at the proposed CO2 taxation levels, it would be more economical for the CTL industry to pay CO2 penalties than to switch to nuclear co-gen.

As a further calculation, it was instructive to learn at what nuclear plant price level the CTL facility would yield an IRR=8.4% (reference scenario with tax penalty included). This is achieved when the nuclear module price is 475M€ (approximately 49% down), assuming 90% availability. We conclude that an investment in nuclear co-generation in South Africa, in a scenario where carbon taxation has been introduced and the nuclear option must compete with conventional CTL paying CO2 taxation penalties, nuclear co-generation will only become an investment option if the current target overnight cost of a nuclear module (2x250MW reactors) is reduced by 50%. Such a facility would require 16 reactors and should be operated at an availability of at least 90%.

In a final calculation the effect of the economy of a larger scale nuclear plant module was studied, based on the following assumptions:

- Nuclear module capacity 625MWth.
- Module cost: 70% of the cost of a 2x250MWth plant, namely M€651.6
- Nuclear steam and electricity selling prices to the CTL plant determined such that the nuclear plant achieves a 6% IRR.
- All other assumptions and expenses, as were made for the 2x250MW configuration, were retained.
- Nuclear plant availability was “tuned” to yield an integer number 625MW modules. It turned out that an 80,000bpd CTL plant would need 7 modules, producing at 82% availability. (Or 6 at 95% availability, deemed to be unachievable and not modelled)

Table 24 and **Table 25** show results for the 625MW configuration. CTL IRR in this case was 8.2% (vs. 8.4% for the case when the CTL facility simply pays the CO2 penalty). It follows that this scenario exhibits some economic merit. It is worthy of more detailed analysis.

Nuclear plant selling prices			
	R/ton	€/ton	€/GJ**
Nuclear steam	285	28.0	8.40
Oxygen (109)	584	57.3	-
	R/MWh	€/MWh	€/GJ
Nuclear Co-gen electricity	514	50.4	14.0
Electricity (Eskom)	-	-	-
**40bar, 450C	3330	KJ/kg	

Table 24: Utility costs to the CTL facility. Scenario 1. 625MW Nuclear plant at availability = 82%

		Process stream selling prices. Scenario 1.											
Process stream identification	Process stream species (ton/h)							€/ton	€/GJ	Allocated to species (in €/GJ)*			
and %	H2	CO	CH4	C2H6	CO2	other	LHV	(R10.5/€)		H2	CO	CH4	C2H6
	120.1	10.2	49.9	47.2	0	0	MJ/Kg						
Pure gas (129)	74.2	653.9	137.6	6.2	28.8	0.12	25.2	163.4	6.47	2.54	1.90	1.95	0.08
%	8.2%	72.6%	15.3%	0.7%	3.2%	0.0%							
SMR (H2+CO) (119)	42.6	190.6	23.7	0	91.4	295.3	12.8	113.3	8.84	5.49	2.09	1.27	-
%	6.6%	29.6%	3.7%	0.0%	14.2%	45.9%							
SAS feed stream (129+119)	116.8	844.5	161.3	6.2	120.2	295.4	20.1	131.7	6.57	2.97	1.83	1.71	0.06
%	7.6%	54.7%	10.4%	0.4%	7.8%	19.1%							
										(€/GJ)(GJ/ton)/1000=€/Kg			

Table 25: Process stream selling prices. Scenario 1. 625MW Nuclear plant at availability = 82%

As an extension of the above configuration, the effect was studied of a higher CO2 taxation level. Nuclear co-gen in scenario 1 studies removes only CO2 emanating from the steam boilers (about 50% of total CO2 emission). At tax level about 16€/ton CO2, nuclear supported CTL becomes uneconomical - not because of the cost of nuclear steam and electricity, but because of the high cost of CO2 penalty payable on the portion of CO2 that is NOT eliminated by nuclear. Hence, if we put penalties more than 16€/ton in the South African scenario, it will kill CTL (and NCTL will not come to the rescue).

CO2 recovered by both Rectisol and cold separation is almost 100% pure. Carbon Capture and Storage (CCS) is probably the most economical way to dispose of excess CO2. Although not studied, this route is attractive, since the “capture” part of CCS is reported to account for about 60% of the cost of CCS. This is already done in a conventional CTL process. Of course the challenge of CSS is to find an acceptable repository.

Sasol recently shifted its business focus away from CTL to Gas-To-Liquid (GTL) production. This move was evident from the shelving of a planned new CTL plant in the Waterberg area in South Africa. There were many reasons for this change in direction. It is outside the scope of this report to elaborate on these, save to say that the large CO2 footprint of Sasol’s CTL process played its part.

South Africa (and many other counties) has vast coal resources. If CO2 emission of the CTL process could be economically reduced, these resources offer many more opportunities for CTL projects. The study scenarios below aimed at further reducing CTL’s CO2 footprint.

5.4.2 Scenario 2

Please refer to section §5.2.4.4 for a description of scenario 2. **Table 26** shows some results of the ASPEN process simulation.

	CO2 emitted (million ton/annum)	Electricity demand	Coal gasified (Mton/year)
Scenario 1	14.7	634MW	12.6
Scenario 2a.	13.7	1283MW	12.6
Scenario 2b.	11.2	1559MW	10.4

Table 26: CO2 reduction for Scenario 2

It is clear from **Table 26** that this configuration requires a huge increase in electrical energy for limited reduction in CO2 emission. In the light of the results reported for scenario 1, it is a foregone conclusion that that scenario 2 will not meet the economic feasibility criterion. Hence it was not simulated.

The disappointing reduction in CO2 emission stems from the necessity to introduce the water gas shift reaction to get the desired H2/CO ratio at the synthesis reactor input. This reaction generates significant CO2. Note that coal gasified reduces when additional CH4 is “dry” reformed. Compare scenarios 2a and 2b. Saving thus obtained (2.2 million ton coal per annum at 0.91€/GJ) is insignificant when compared to cost of additional nuclear electricity (276 MW at 19.3€/GJ)

5.4.3 Scenario 3

Please refer to section §5.2.4.5 for a description of scenario 3. **Table 27** shows some simulation results for scenario 3.

	CO2 emitted (million ton/annum)	Electricity demand	Coal gasified (Mton/year)
Scenario 1	14.7	634MW	12.6
Scenario 3a.	13.55	1329MW	12.6
Scenario 3b.	12.1	1654MW	10.9

Table 27: CO2 reduction for Scenario 3

Reduction in CO2 stems from the reduction in coal gasified. Since the latter only reduces marginally as a result of “wet” PAR of CH4, the reduction in CO2 emission is also marginal. In the case where PAR is implemented, syngas with a CO to H2 molar ratio of 1 to 1 is produced during dry reforming. This leads to a shortage in H2 that would be fed to Fischer-Tropsch synthesis where a ratio of 1:2 is generally required. Without resorting to additional hydrogen generated from nuclear energy, steam was introduced to increase this ratio. In doing so the water gas shift reaction is at equilibrium producing the necessary hydrogen, but resulting in the unavoidable production of CO2. As was the case for scenario 2, this comes at a huge cost in the form of nuclear electricity. By the same argument scenarios 3 will not meet the economic feasibility criterion either.

5.5 Conclusions

The study came to the following conclusions:

- The price of nuclear hydrogen, produced by the HyS process, is at least 5.4 and can be as much as 10 times more expensive compared to the price of hydrogen produced by the water-gas-shift reaction in a conventional Lurgi gasifier as done in a typical CTL process. This finding makes the introduction of nuclear energy into a CTL process through the nuclear hydrogen path an unlikely future technology.
- Increasing nuclear plant availability from 80% to 90% has the benefit of having to install 16 instead of 18 nuclear reactors to serve the process heat and electricity needs of a 80,000

barrel/day CTL facility. Such a facility does not rely on process steam and electricity from coal, thereby reducing its CO2 footprint by 50%. When the transfer price of steam and electricity is determined such that the nuclear facility yields a 6% post tax real IRR, the CTL facility IRR drops from 9% for a conventional CTL plant to 5.9%. Reducing CO2 footprint via the nuclear heat and electricity route therefore comes with a severe penalty in the profitability of an investment in CTL.

- If carbon tax is implemented in South Africa it would cause the IRR of an investment in CTL to fall from 9% to 7.8%. It is therefore more economical to pay CO2 penalties than to switch to nuclear co-generation.
- Imposing a CO2 tax penalty on CO2 emission generated by the CTL process other than through CO2 emission from steam boilers, yielded an IRR=8.4%. When the transfer price of nuclear process steam and electricity is set such that the nuclear facility yields a 6% post tax real IRR, the CTL facility achieves an 8.4% IRR when the nuclear module's (2x250MW) overnight cost is reduced by 49% to approximately 475M€.
- Substituting steam methane reforming with plasma arc reforming in a conventional CLT plan significantly increases its electricity demand, with only a modest reduction in CO2 emission. If electricity is to be purchased at a price level that would make a nuclear plant a feasible investment, the CTL facility would be totally uneconomical.
- The overall conclusion from this study is that substitution of coal generated process steam and electricity offers the best opportunity for nuclear co-gen, when compared to all other coupling configurations detailed in this report. The challenge of this technology remains its high cost and the impact of such on the profitability of the conventional CTL route.

6 SYNKOPE: Synergetic coupling of energy sources for efficient processes

This chapter is a contribution of TU DRESDEN to Deliverable D4.41

6.1 Introduction

Goal of the R&D project SYNKOPE (08/2012 – 11/2014) was to design a nuclear cogeneration system for the refinement of coal mined in the tri-border region of the Free State of Saxony (Germany), the Czech Republic and Poland. The project was approved and sponsored by the Saxon Regional Government in Germany (Sächsisches Ministerium für Wirtschaft, Arbeit und Verkehr) in the framework of the European Regional Development Fund. The challenge was to identify future options for exploiting regional coal resources while meeting ambitious CO2 reduction targets. As a result, a process for the efficient transformation of coal into the liquid fuel methanol was designed, yielding a higher value creation per ton of CO2 emitted compared to the steam electric generation currently pursued.

6.2 Achievements

The system needed to comply with two boundary conditions:

- Nuclear heat source with enhanced safety characteristics,
- Compatibility with the quality of the coal mined in the tri-border region.

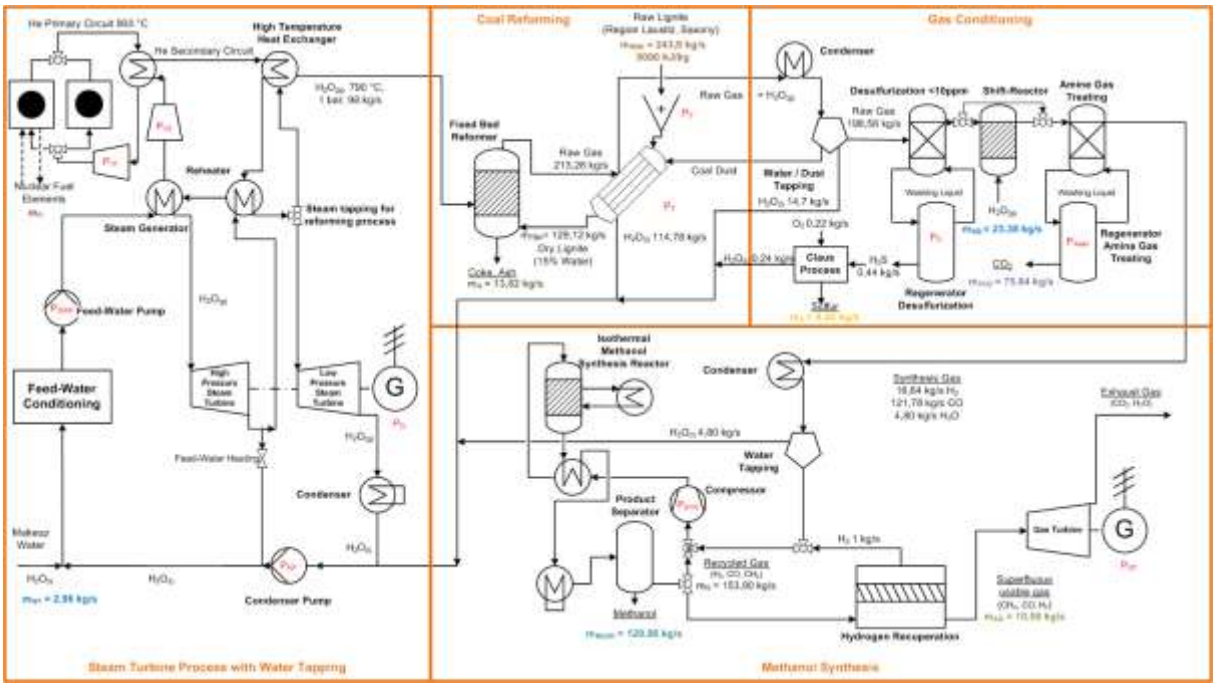


Figure 52 : SYNKOPE Process

Within the project, a steam gasification and liquefaction process as shown in **Figure 52** was identified to be most promising with regard to CO2 reduction potential. High temperature steam is to be provided by a double HTR block consisting of two units rated at a thermal power of

350 MWth and a maximum coolant outlet temperature of 900 °C. The research work was carried out by four Saxon research institutions with the lead of Technische Universität Dresden and support by the Czech Research Centre Rež and the West Pomeranian University of Technology, Poland.

It focused on key issues of the cogeneration system with regard to both technological feasibility and economic viability:

- Thermal hydraulics and heat transfer simulations to confirm the inherently safe decay heat removal during normal and accident operation. The worst case scenario considered was a station blackout with subsequent outage of the helium blowers.
- Preparation and testing of nanocrystalline SiC coatings for use in both structural (SiC composites) and functional (TRISO particles) components.
- Qualification of SiC bulk materials and joints for use in chemically aggressive high temperature process atmospheres.
- Optimization of the refinement process as a function of the quality of the available coal.
- Integration of supplementary refinement technologies for hydrogen generation (ultrasound assisted electrolysis) and CO2 hydrogenation.
- CO2 life cycle analysis of the overall cogeneration system and economic viability study.

The co-generation nuclear heat source was scaled in a way such that it provides all of the heat required by a totally allotherm coal refining process and satisfies most of the electricity requirements. However, if methanol output has to be reduced due to lack of demand, the system may switch to higher electricity generation to supply the off-site electrical grid.

At 100 % methanol production the conversion efficiency of the overall system, defined as:

$$\eta = \frac{h_{LHV,Methanol} \cdot m_{Methanol}}{P_{HTR} + h_{LHV,Coal} \cdot m_{Coal}}$$

was determined to be 84 %.

For a nuclear heat source consisting of two HTR units (total thermal power of 700 MWth), the annual output was determined to be 4.8 Mt at an average capacity factor of 0.9, Specific levelized costs were calculated to be 90 EUR/t, compared to 130 EUR/t in a conventional plant.

Capital costs were assumed to be 12 % in both cases, although they would likely be higher if the first-of-a-kind nuclear cogeneration plant were to be built in a liberalized energy market. However, as life-cycle CO2 emissions in the nuclear cogeneration plant are approximately half of those in a conventional plant (0.7 tCO2/tMethanol and 1.4 tCO2/tMethanol, respectively), the co-generation plant appears to be a viable option for the European energy market, in particular if CO2 emission prices increase due to more ambitious EU targets and methanol prices remain at current levels (350 EUR/t).

Figure 53 shows the share of costs incurred for the production of 1 t of Methanol.

As the nuclear heat source has to be operated in conjunction with a sophisticated chemical plant, possibly in proximity to residential areas, safety aspects were given the highest priority within the project.

The HTR nuclear heat source was not only chosen for its possibility to provide high-temperature heat, but primarily for its robustness in case of station-black-out incidents. Using a coupling of the neutronics code DYN3D and the FEM code COMSOL it was shown that the HTR core would withstand such incidents without reaching critical temperatures even if emergency power was disabled indefinitely. Maximum temperatures would be reached 40–60 min after reactor shut-down and decay heat removal would primarily occur via heat conduction and thermal radiation instead of convection. Thus, large-scale release of radioactive contamination due to station-blackout incidents as happened in the Fukushima accident can be excluded.

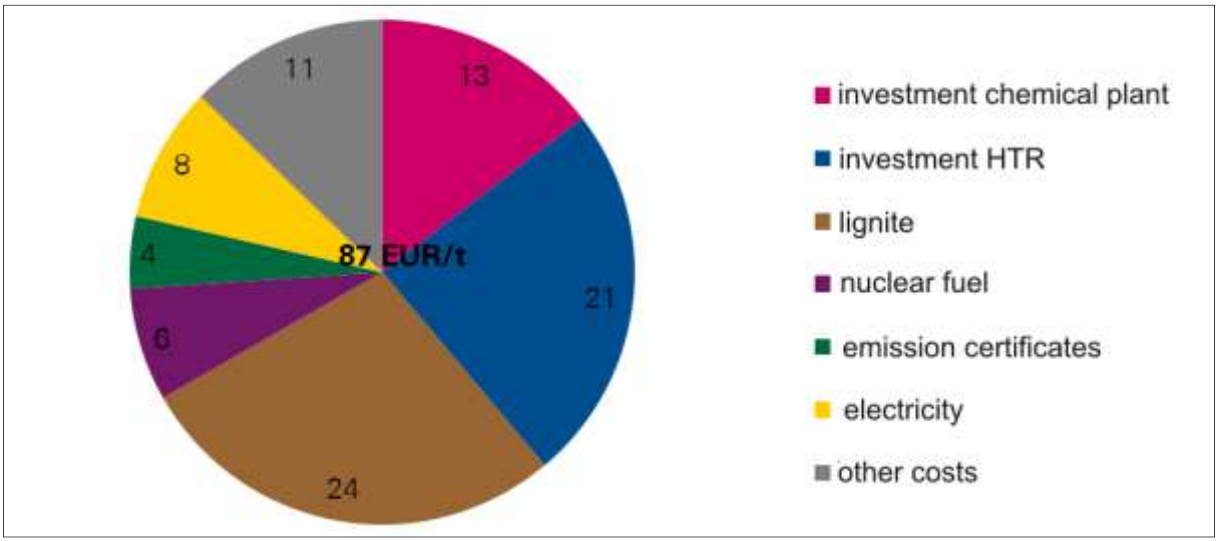


Figure 53: Cost distribution to generate 1 t of methanol using the SYNKOPE process

For regulatory reasons, the minimum distance between nuclear and chemical plant was determined to be 200 m based on the TNT equivalent of the refining process.

The helium/water steam generator was designed accordingly in the project requiring a temperature difference of 110 °C between reactor helium outlet temperature and process steam inlet temperature.

The chemical process was shown to require a steam temperature of no less than 790 °C for effective steam reforming. This yielded the outlet temperature requirement for the HTR of at least 900 °C, beyond the current state of the art of 750 °C.

In order to achieve the envisioned temperature level, two strategies can be pursued:

- Development and qualification of high-temperature ceramic materials allowing higher HTR operating temperatures or
- Keeping the HTR outlet temperature at 750 °C and applying heat pumps on the secondary side to increase the process heat temperature by about 100 °C.

As the latter option would require a large amount of additional electricity weighing on overall process efficiency, only the first option was considered. Therefore, two work packages in the project focused on the enhancement of SiC ceramics used as structural and functional materials both for conventional and nuclear high-temperature applications. SiC coatings and joints, identified as representing the most critical areas of research towards qualification of SiC materials, were prepared and tested under high temperature corrosive conditions.

6.3 Conclusions

In conclusion, the SYNKOPE project showed that nuclear co-generation plants represent a solution for continued use of coal and lignite in the three-border region Saxony – Poland – Chez Republic even if stricter EU CO2 emission targets will be imposed on the energy sector.

The system designed in SYNKOPE, consisting of two HTR units for heat and electricity generation and a refining plant for coal conversion, would account for annual production of 4.8 Mt of methanol, worth 1.3b EUR at current market prices. This represents a value creation of about 300M EUR/a, equivalent to more than 90 % of gross value creation by current steam-electric power generation.

Research results showed that the chosen nuclear heat source exhibits enhanced safety features as it withstands station-blackout incidents without release of radioactive contamination or loss of investment capital. However, further research is needed for enhancement of the heat exchanger system and the qualification of SiC structural materials in order to provide process heat temperatures of at least 790 °C as required for an efficient conversion process.

These aspects will be further examined in the follow-on project SYNKOPE-Flex. In this project, high-value substances such as aromatic hydrocarbons will be considered as potential products as they require lower HTR outlet temperatures and may offer an even higher ratio of value creation per emitted CO2.

7 Analysis of a combined HTR-peak-load hydrogen turbine system

This chapter is a contribution of WUT to Deliverable D4.41

Abstract

The aim of the investigation was to realise a complex calculations of a new water-steam system with peak-load hydrogen turbine to be applied in nuclear units with gas-cooled reactors of GenIV. The maximum temperature of helium was limited to 750 °C. The system's characteristic feature is the presence of two heat sources: a nuclear steam generator; and a hydrogen-oxygen combustion chamber. The main idea is to create a system capable to operate in two modes, with one or two heat sources, which leads to a significant output change. The analysis concerned also the rationality of hydrogen production and utilisation. An additional aim of the research was to determine the optimal solution regarding the system performance and the capability of its technical realisation. The obtained results are promising: the system performance is high; and its operational parameters are technically realisable in today's conditions. In addition, it enables an emission-free, dispatchable electricity generation during the daytime demand peak. However, in order to fully assess the rationality of its implementation, detailed data on the efficiency of hydrogen production utilising nuclear heat of 750 °C is needed.

7.1 Introduction

A growing interest in hydrogen technologies could be observed in recent years. It is caused by the conviction, that the product of combusting hydrogen with pure oxygen does not contaminate the environment. This would be true, weren't organic fossil fuels used its production, and it is not the case today. In addition, the notorious omission or reduction by the supporters of hydrogen applications in the power industry and transport of the importance of two facts – that it is not a primary energy carrier, and that its properties are disadvantageous regarding storage and distribution – is rather confusing.

Hydrogen is the most widespread chemical element on the Earth and in space. However, on our planet it occurs almost exclusively in compound form – it is present in the majority of inorganic compounds (e.g., in water, acids, alkali) and in all organic compounds (e.g., in hydrocarbons, fats, sugars, alcohols, proteins, acids). There are only negligible amounts of its free form (e.g., in the air and natural gas). This means, that hydrogen has to be produced by decomposing its chemical compounds, which requires energy supply. Therefore, in the process of conversion of energy from its primary to final (usable) form, the production and utilisation of hydrogen is an additional stage. The rationality of its introduction could depend on different criteria, but first of the effect on the overall energy conversion efficiency and the total amount of pollutants emitted to the environment should be taken into account.

Since the end of the nineties of the last century, a distinct return of the interest in nuclear power technology is observed. It seems that four main reasons could be distinguished in this case. First of all, because of the high prices of organic fossil fuels, the electricity generation cost in the nuclear power sub-sector became the lowest in the thermal power sector, or comparable to that of the coal power sub-sector. In addition, the standardisation, introduction of modular structure, and project simplification, together with the unification and acceleration of the verification and construction/operation licensing procedures for units with reactors of GenIII, III+ and IV, and the extension of their designed operation lifetime to 60 years are to sustain this tendency.

At the same time, the nuclear safety is a priority in designing reactors of new generation. The development of information systems and automatics, together with the new solutions in the scope of active and passive safety systems cause that today in the NPPs under construction the probability of a severe accident is reduced almost to zero.

The limited sources of organic fossil fuels are also important. Different sources give different data, but the general conclusion is that the terms of their exhaust should be calculated in hundreds of years. In the case of nuclear fuel it is thousands of years, provided wide implementation of fuel breeding.

Another argument in favour of developing nuclear power, connected with the need to reduce the emission of pollutants, is the practical incapability to replace fossil fuels with renewable sources. The utilisation of solar energy, wind energy, biomass, and biofuels is limited by the space, needed for their conversion or production, connected also with the climatic conditions. In addition, the undispatchability of the first two is a negative factor, so is the energy-consuming production of biofuels. It seems that the mechanical energy of water remains the only alternative, but its resources are almost fully utilised in the developed countries, and in the others the gigantic investment costs (and often also environmental costs) are an effective barrier for the development of this energy generation branch.

In the last years, a political argument has been added to the above-mentioned four economical-technical reasons: the energy security. Significant majority of the countries imports needed primary energy carriers and could feel endangered by the permanent high level of their prices, and supply uncertainty. Because of the relatively small volumes, facilitated transport and storage, and multiplicity of potential suppliers, the nuclear fuel is a promising alternative to the organic fossil fuels. Today this concerns mainly the power industry, but projects of using GenIV HTRs to produce hydrogen for coal gasification (methane synthesis) or carbon dioxide sequestration (methanol synthesis) are already developed. The intention is to reduce the import of liquid and gaseous primary energy carriers by the means of the so called “nuclear-coal synergy”.

All known – developed and under investigation – hydrogen production methods lead to a decreased overall energy conversion efficiency. Along with obvious losses, in the case of using organic fossil fuels this means an increase of the pollutant emissions to the atmosphere. Therefore, it seems that the only relevant technology, the implementation of which could be reasonable, are the thermochemical water dissociation cycles supplied with nuclear heat. Together with electrolysis of water, supplied with nuclear-generated electricity, these would be the only emission-free hydrogen production methods.

Simultaneously with the energy inefficiency, hydrogen is effectively eliminated from application in transport by technical problems, connected with medium- and long-term storage, and distribution. More efficient, cheaper, and easier to be realised is here the electric motor. The use of hydrogen in the power industry seems to be rational only under the condition that it will serve to cover peak electricity demand (an emission-free cover of the basic demand could be realised directly by nuclear power units).

The common features of the recently investigated hydrogen turbine systems are: using the hydrogen combustion as an only heat source; and presence of a high-pressure part with supercritical operating parameters and of a low-pressure part with a condenser. Taking this into account, every-day start-up and shut-down of such systems would be either technically impossible/inadvisable or, in case of idle run, too expensive. Therefore, tahy should operate continuously, with a significant load difference between the daytime demand peak and nighttime demand trough periods, which would result in lower net electric efficiency and – more important –

low overall energy conversion efficiency. It has to be noted here that the highest calculated net electric efficiency of such a system equals 59.9%.

The assumption of using hydrogen in the power industry only for covering the daytime peak demand imposed the need of working out a new system, the configuration of which would make every-day quick start-up and shut-down of the hydrogen turbine possible.

7.2 Rationality of hydrogen production

The advantages and disadvantages of using hydrogen as a fuel are well known. Its physical properties (lowest density, highest diffusivity) cause that it mixes perfectly with oxidiser, and than burns completely. Very high efficiency of hydrogen turbine systems are obtainable, assumed pure oxygen is applied and heat is directly supplied to the working medium. At the same time, hydrogen gives relatively low energy density and is difficult to be stored and distributed, especially as a transport fuel.

All the hydrogen production technologies are energy consuming; i.e., the relevant chemical processes are endothermal, and the electrolysis requires electricity supply. This means that the hydrogen fuel is an additional, intermediate stage of the energy conversion process. An advantageous introduction of such an additional stage is possible only if, in result of it, the overall energy conversion efficiency increases compared to the existing technologies using the same primary energy carriers. However, from financial and/or environmental point of view, a solution, in result of which this efficiency does not increase, but the emission of pollutants considerably decreases, could also be profitable. In such cases certain opposition of financial priorities to political ones (connected with environment protection) may appear. The settlement of this opposition could be different in different countries.

The hydrogen production technologies could be divided into two main groups: pure water dissociation; and others. The today most popular technology – steam methane reforming (SMR) – belongs to the second group, as well as the coal gasification using steam. Their efficiencies does not exceed 75% and 60%, respectively. Their common features are that fossil fuels are being used, and oxygen is not being produced.

The first group includes water electrolysis, and thermochemical cycles of water dissociation. In both cases, along with hydrogen, oxygen is being produced. The efficiency of the so called high-temperature water electrolysis exceeds 92%, while that of the thermochemical cycles obtains 52+9% (combined hydrogen and electricity production, respectively) for 950 °C of the supplied heat. Unfortunately, there are no relevant data for 750 °C, so it was impossible to calculate the overall energy conversion efficiency of the proposed system, assumed the heat for the hydrogen production is supplied by HTRs.

Primary energy carrier	Conversion process with hydrogen production			Simple conversion process (without hydrogen production)	
	Hydrogen production installation type	Hydrogen production installation efficiency	Overall energy conversion efficiency	Type of simple system (power unit)	Overall energy conversion efficiency
Coal	Gasification using stem	≤ 60%	**≤ 36%**	Supercritical unit	**45%**
Natural gas	Steam methane reforming	≤ 75%	**≤ 45%**	Combined cycle	**55%**
Water	High-temp. electrolysis	92%	**47%**	Water turbine	**85%**
Nuclear fuel	High-temp. electrolysis	92%	**17%**	PWR unit	**32%**
Nuclear fuel	High-temp. electrolysis	92%	**29%**	HTR unit (950 °C)	**52%**
Nuclear fuel	Thermochem. cycle (S-I)	52+9%	**40%**	HTR unit (950 °C)	**52%**

Table 28: Comparison of energy conversion efficiency with and without a hydrogen production stage for the basic sources in the utility power industry

The univocal conclusion based on a comparison of energy conversion processes using the same primary energy carriers and including or not hydrogen production and utilisation for power generation purposes is that the introduction of hydrogen stage (with assumed hydrogen turbine net electric efficiency of 60%) would always result in decreased overall energy conversion efficiency, increased fuel consumption, and – in the case of organic fossil fuels – increased emission of pollutants. In addition, for coal and natural gas, energy losses for oxygen production should be taken into account, which should result in further decrement of the overall efficiency. The results of this comparison are set in **Table 28**.

The above-presented review does not include solutions, in which the introduction of hydrogen production stage enables replacement of organic fossil fuels with nuclear sources, thus reducing or liquidating the pollutant emissions. Exactly such a case – of replacing in the utility power industry the today-applied peak sources (coal units, gas turbines, Diesel engine systems) with peak-load hydrogen turbines – was subject to this analysis. Despite of decreased overall energy conversion efficiency, such a solution would enable zero-emission covering of the whole electricity demand.

The power industry share in the consumption of organic fossil fuels equals about 40%. Their replacement in the utility power industry with nuclear and hydrogen fuel seems to be much easier than in other industrial branches and transport. The need to apply hydrogen results from the inability to cover the daytime peak electricity demand directly by nuclear units, for the specific nuclear reactor technology precluding every-day neutron power change. At the same time, the concept of zero-emission covering of the whole electricity demand (i.e., using nuclear or renewable primary energy sources) limits the applicable hydrogen production methods to water electrolysis and thermochemical dissociation.

The water electrolysis as a hydrogen production method for electricity generation purposes is the worst possible solution, regarding the overall energy conversion efficiency (**Table 28**). In addition, its application would impose a specific limitation: the hydrogen production and utilisation should take place alternately. This means that hydrogen could be treated as an energy storage medium, and its chemical energy used similarly to the potential energy of water in pumped-storage power stations; i.e., to move the electric energy generated during the nighttime demand trough to the daytime peak period. This concept is illustrated in **Figure 54**.

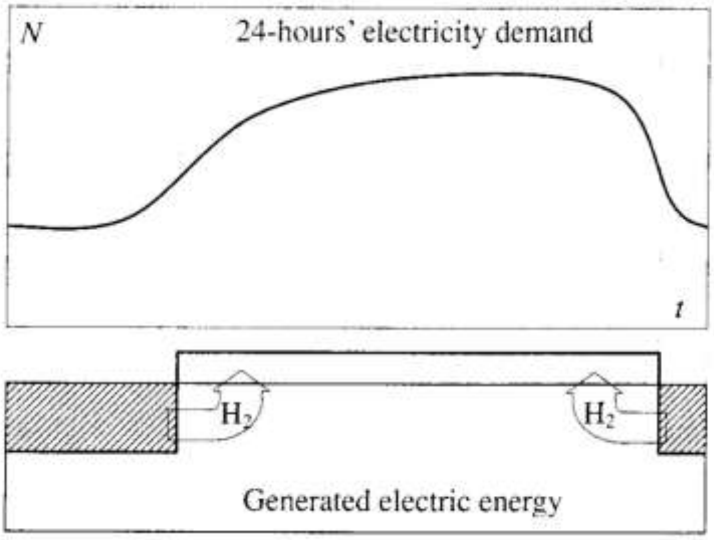


Figure 54 - Concept of a hydrogen energy storage cycle. N: Electric power; t: Time

The storage efficiency, understood as the ratio of the electric energy recovered during the daytime peak and the electric energy generated during the nighttime trough, should be compared to the efficiency of pumped-storage power stations, which reaches about 70%. In the case of hydrogen energy storage cycle, this efficiency would be equal to about 55% (electrolysis efficiency, 92%, multiplied by hydrogen turbine net electric efficiency, 60%).

The above-mentioned limitation does not concern energy conversion chains containing thermochemical water splitting cycles. In such cases, hydrogen could be used for concentrating the electricity generation during the daytime period, which also could be perceived as a form of energy storage. This concept is shown in **Figure 55**. Direct determination of the storage efficiency is impossible here, as the input quantity is not electric energy, but heat generated in a HTR. A more complex analysis of the overall energy conversion efficiency has to be undertaken. An example of a preliminary result of such an analysis is given in **Table 28**. For the system under consideration (750 °C) similar analysis would require data concerning the efficiency of the relevant thermochemical cycle.

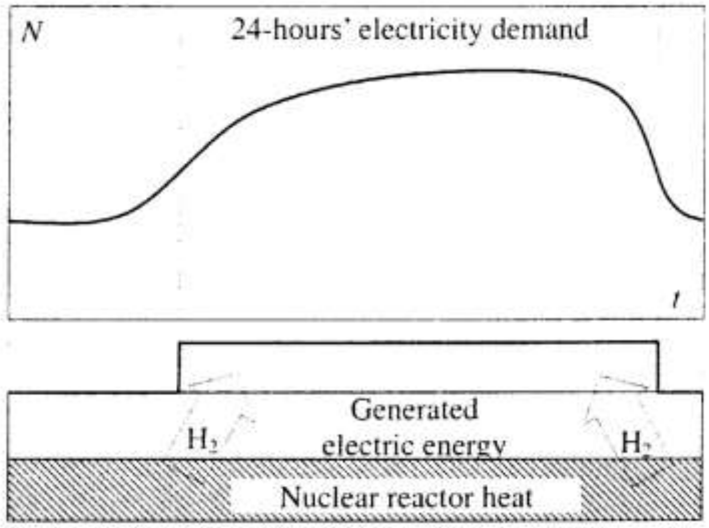


Figure 55 -Concept of electricity generation concentration using hydrogen.
N: Electric power; *t*: Time

7.3 Water-steam system with peak-load hydrogen turbine

The applicability study on the hydrogen turbine systems elaborated up to now shows that none of them could be used in the frames of the above-described hydrogen energy storage cycle. Therefore, a necessity to design a new system appears, the configuration of which would allow every-day quick start-up and shut-down of the hydrogen turbine. The conclusions of that study, and the explicit definition of the new system's purpose allowed to introduce three initial, special requirements related to it:

- The system configuration should provide continuous operation of a maximum number of its components, especially of the high- and low-pressure components, incl. the condenser;
- Working medium parameters realisable in today's conditions should be applied, and application of extreme pressure and temperature at the same point should be avoided;
- In order to obtain a satisfactory overall energy conversion efficiency, the system should provide an efficiency of converting the hydrogen chemical energy (heat of combustion) higher than 60%.

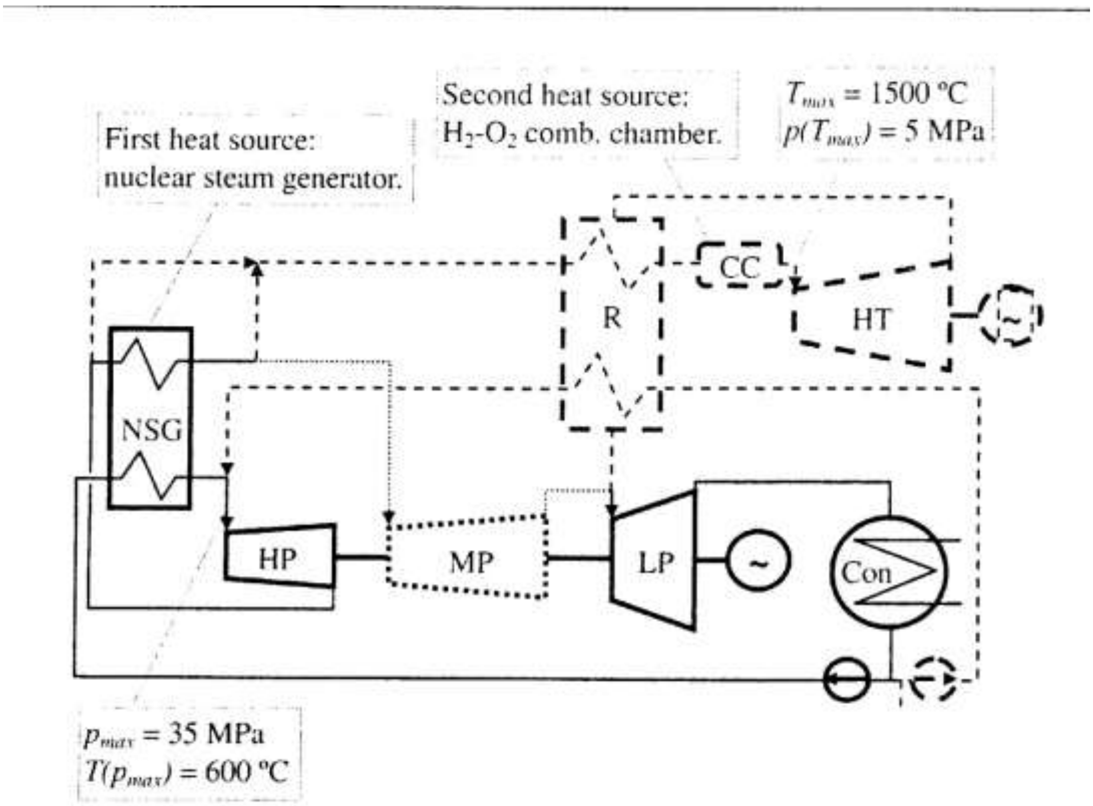


Figure 56 -Concept of the new water-steam system with peak-load hydrogen turbine.

NSG: Nuclear steam generator; CC: Hydrogen-oxygen combustion chamber; HP: High-pressure steam turbine part; MP: Medium-pressure steam turbine part; LP: Low-pressure steam turbine part; Con: Condenser; HT: Hydrogen turbine; R: Recovery boiler. Solid lines: Permanently operating components; Point lines: Components operating in nighttime mode; Dashed lines: Components operating in peak mode

These requirements were met by limiting the range of the hydrogen turbine operating parameters to medium pressure and introducing one heat source more (along with the hydrogen-oxygen combustion chamber) in the form of a nuclear steam generator in order to keep the high- and low-pressure system part in continuous operation. In the matter of fact, this leads to a solution, in which the hydrogen turbine is added to the water-steam loop of a HTR power plant. This concept is shown in Fig. 3. Its main idea is to enable system operation in two modes: basic mode, with one heat source (during the nighttime demand trough); or peak mode, with two heat sources (during the daytime demand peak). The nuclear steam generator (NSG) is the basic source here, supplying heat continuously, and the hydrogen-oxygen combustion chamber (CC) is the peak source. The whole hydrogen part of the system – recovery boiler (R), combustion chamber, and turbine (HT) – is located parallel to the medium-pressure part (MP) of the steam turbine, being a flow path alternative to it. This means that in the nighttime mode all the working medium flows through the MP turbine part, while the hydrogen part is shut down, and in the peak mode all the working medium is directed to the hydrogen part, while the MP part is shut down. In such a system, keeping the shut-down machines and devices hot and their rapid start-up is not difficult. In **Figure 56**. the alternative flow paths are marked with point and dashed lines, respectively. The components operating permanently are marked with solid lines. It is assumed that the nuclear steam generator operates with constant thermal load. The need of cooling the steam downstream the hydrogen turbine (heat recovery), caused by its relatively high temperature, enables heating of an additional amount of working medium. This leads to a higher load of the the high- and low-pressure turbine parts (HP and LP) and the condenser during operation in peak mode.

The following main assumptions were made in relation to the system operating parameters: for material reasons, the temperature of medium heated in heat exchangers should not exceed 600 °C; the working medium temperature at the hydrogen turbine inlet should not exceed 1500 °C; in result of the applicability study on recently elaborated hydrogen turbine systems, the maximum pressure at the steam turbine inlet was limited to 35 MPa, and at the hydrogen turbine inlet to 5 MPa. These assumptions enable implementation of the proposed concept using existing and mastered technologies.

7.4 Investigation results

A detailed simulation-based investigation was realised, incl. preparation of an overall, consistent model of the system. First of all, it was assumed that the forced circulation of helium in the HTR should be realised by a turbocompressor (turbine and compressor of the same power and on the same shaft). Thus, the nuclear steam generator operating parameters were determined, being boundary conditions for the main model; i.e., the model of the proposed water-steam system. Next, its particular calculation modules were prepared, verified, and integrated. The highest attention was paid to the assumptions concerning the heat transfer and expansion conditions in the relevant system components. This concerned especially the high- and low-pressure steam turbine parts, the load of which could differ significantly in the two operating modes (because of the additional amount of working medium, heated in the recovery boiler and generated in the combustion chamber in peak mode). The determination of optimal performance solution was an additional, but important aim.

The basic assumptions, constituting the boundaries of the performed investigation, could be divided into two groups: general ones, concerning material and thermal-hydraulic problems; and special ones, concerning the capabilities of technical realisation. Examples of assumptions of the first group are the applied values of turbine stage group internal efficiency or compressor stage group internal efficiency, and of the second group the limitation of the lowest pressure in the recovery boiler to 1 bar in order to avoid its inclusion to the vacuum part of the system. An example of an assumption, connected with both groups, is the limitation of the heated medium temperature at the outlet of each heat exchanger stage (i.e., the nuclear steam generator stages, and the recovery boiler stages) to max. 600 °C in order to avoid application of expensive alloys as structure materials. The most important assumptions, concerning the parameters of machines and devices and working medium parameters limitations, are set in **Table 29**.

Parameter	Value
Helium temperature at the reactor outlet	750 °C
Maximum temperature of heated medium at a heat exchanger outlet	600 °C
Maximum working medium pressure at the HP steam turbine inlet	35 MPa
Minimum working medium pressure at the HP steam turbine inlet	22.1 MPa
Steam pressure at the HP steam turbine outlet	5.5 MPa
Working medium pressure at the hydrogen turbine inlet	5 MPa
Maximum working medium temperature at the hydrogen turbine inlet	1500 °C
Minimum pressure of the cooled medium at the recovery boiler outlet	0.1 MPa
Condensing pressure	3.6 kPa
Minimum temperature difference in the heat exchangers	20 °C
Maximum temperature effectiveness of a heat exchanger stage	0.75

Combustion chamber efficiency	100%
Gas turbine internal efficiency	90%
Compressor internal efficiency	80%
Hydrogen turbine internal efficiency	90%
HP steam turbine part internal efficiency	90%
MP steam turbine part internal efficiency	89%
LP steam turbine part internal efficiency	80%
Pump internal efficiency	90%
Product of mechanical and electric generator efficiency	97%

Table 29: Assumption, concerning parameters of machines and devices and working medium parameter limitations

Some of the above assumptions require explanation and comment. The every-day operation in two modes, very different regarding the load, is a special feature of the system. At the same time, constant operating conditions should be secured for the nuclear reactor. This means that the nuclear steam generator has to operate under identical load in the two modes. For that reason, constant operating parameters of its heating side were assumed.

A sliding-pressure operation was provided for the HP part of the system. As the maximum pressure at the HP turbine part inlet was set to 35 MPa (i.e., on a supercritical level), its minimum value was set to the critical level. The reason was to avoid the need to separate liquid and gaseous phases, which would cause further complication of the system configuration.

In order to keep the heat exchanger dimensions in a reasonable range, limitations concerning the minimum temperature difference in heat exchanger stages (pinch point) and their maximum temperature effectiveness were introduced. The latter is understood as the ratio of temperature differences of outlet and inlet streams.

Model modules corresponding to the system components were built and tested. Next, proper modules were integrated in two configuration versions: a basic one (for operation in nighttime mode); and a peak one (with the hydrogen part – for operation in peak mode). The operating conditions of the high- and low-pressure turbine parts were critical for the question of capability to technically realise the idea of operation of the same system in two significantly different modes. In order to obtain consistent results for the two configurations, numerous simulations were made for each set of assumed parameters (such as working medium pressure upstream the HP turbine part, or its temperature upstream the hydrogen turbine, etc.), using iteration method. A dependence between the mass flow rate and the turbine stage group inlet and outlet parameters, based on the similarity principles (Stodola law), was used for the calculations. Nominal parameters for the HP and LP turbine parts are the parameters of operation with full load; i.e., in peak mode.

The main research aim was to determine the system performance, and the additional aim was to determine the optimal operating conditions (parameters). They were determined in result of the realised numerous simulations of system operation under different conditions. The optimal parameters are shown in **Figure 57** (basic, nighttime mode) and **Figure 58** (peak, daytime mode). The helium pressure in the HTR equals 4.4 and 4.3 MPa at the inlet and outlet, respectively. The realised water-steam cycles are shown in the form of a T-s diagram in **Figure 59**. The optimal system performance parameters are set in **Table 30**.

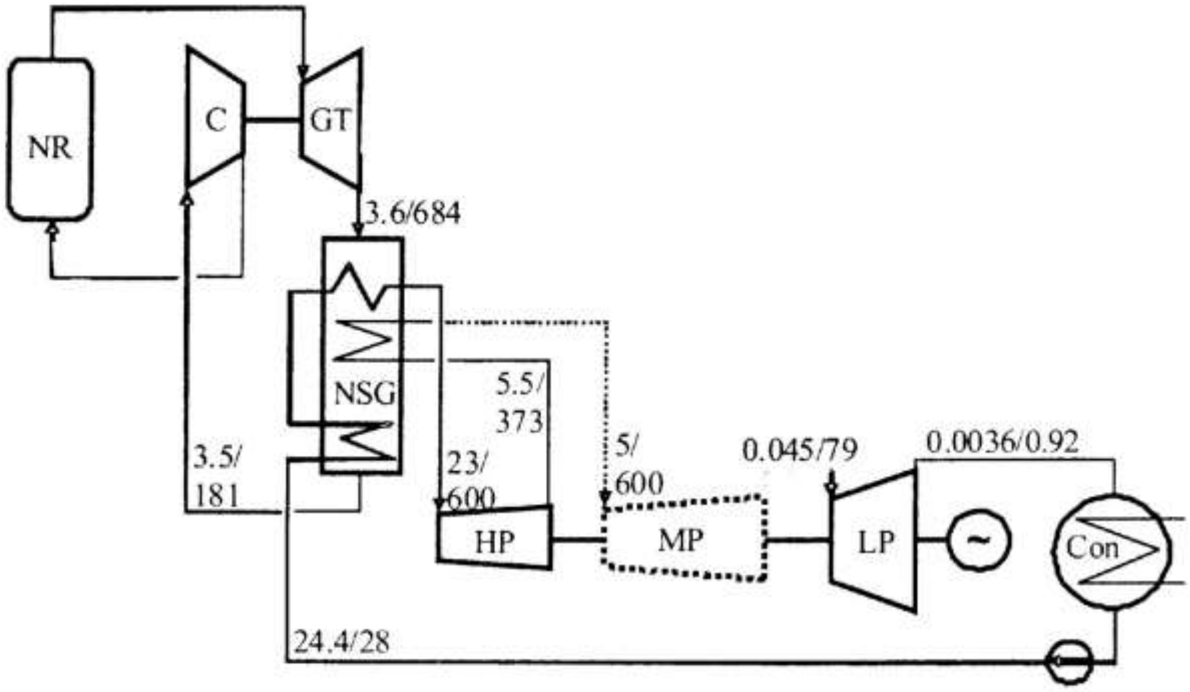


Figure 57- Optimal system operating parameters in basic (nighttime) mode.

NR: Nuclear reactor; GT: Gas turbine; C: Compressor; NSG: Nuclear steam generator; CC: Hydrogen-oxygen combustion chamber; HP: High-pressure steam turbine part; MP: Medium-pressure steam turbine part; LP: Low-pressure steam turbine part; Con: Condenser. Parameters: Pressure [MPa] / temperature [°C] or steam dryness

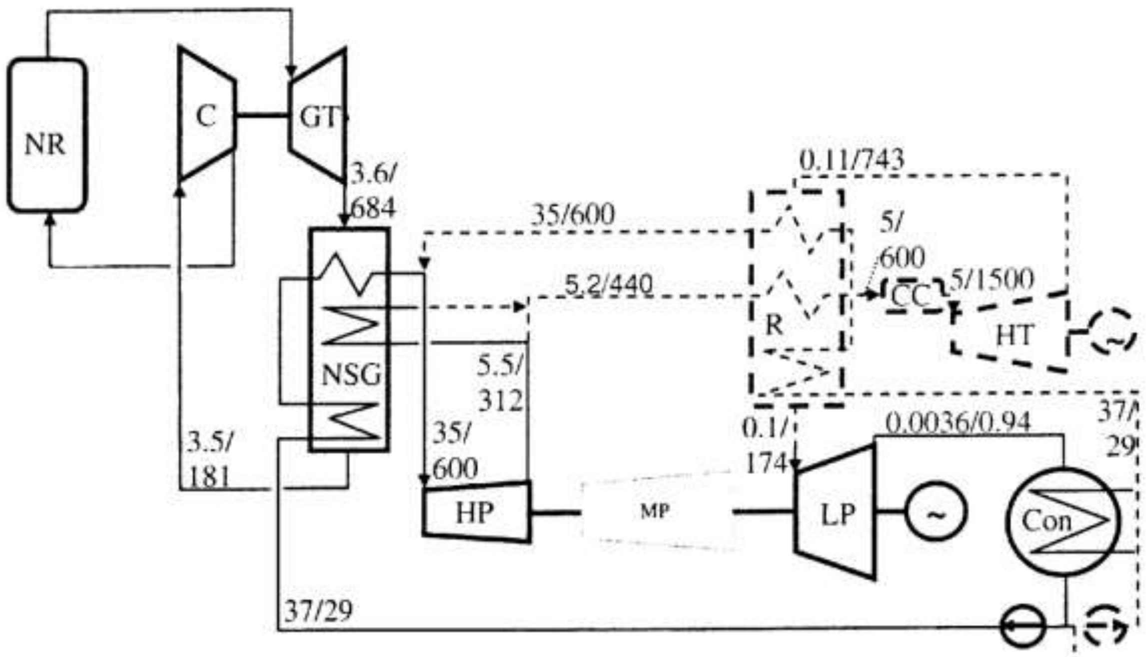


Figure 58 -Optimal system operating parameters in peak (daytime) mode.

NR: Nuclear reactor; GT: Gas turbine; C: Compressor; NSG: Nuclear steam generator; CC: Hydrogen-oxygen combustion chamber; HP: High-pressure steam turbine part; MP (faded): Medium-pressure steam turbine part (shut down); CC: Hydrogen-oxygen combustion chamber; HT: Hydrogen turbine; R: Recovery boiler; LP: Low-pressure steam turbine part; Con: Condenser. Parameters: Pressure [MPa] / temperature [°C] or steam dryness

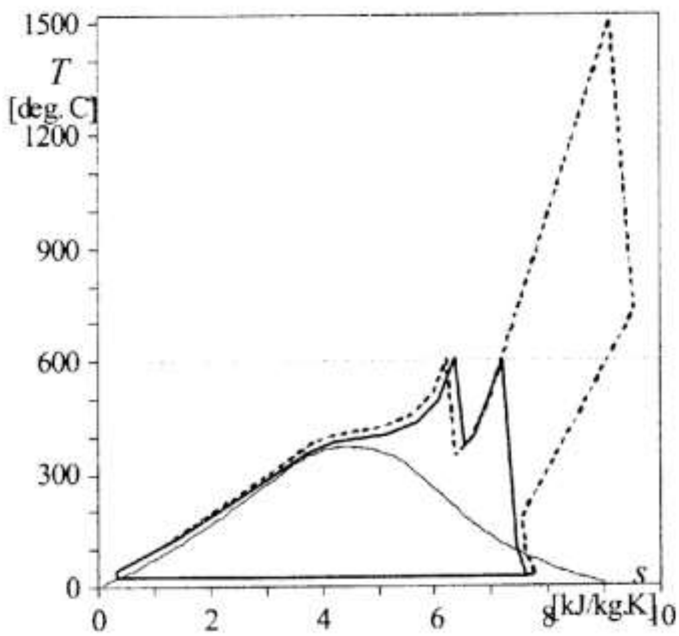


Figure 59 -Realised cycles on a T-s diagram.

Solid line: Nighttime mode; Dashed line: Peak mode

Parameter	Value
System net electric efficiency in nighttime mode	41.3%
System net electric efficiency in peak mode	54.8%
Efficiency of converting the hydrogen chemical energy (heat of combustion) into electric energy (hydrogen efficiency)	63%
Ratio of the mass flow rate through the HP turbine part in peak and nighttime modes	1.6
Ratio of the mass flow rate through the LP turbine part in peak and nighttime modes	1.97
Ratio of the main electric generator power in peak and nighttime modes	0.898
Ratio of the system power in peak and nighttime modes	2.9

Table 30: Performance of the proposed system in optimal operating conditions

It seems that some of the data shown in **Figure 58** and **Figure 59** and **Table 30** require a comment. First of all, the helium pressure in the primary loop (4.4-3.5 MPa) corresponds to the assumptions of the American and South-African engineers (GT-MHR and PBMR), made in order to reduce the dimensions of the particular installation components.

Next, in agreement with the expectations, it appeared that the system performance improves with increasing the pressure and temperature at the high-pressure turbine part inlet, and with increasing the temperature at the hydrogen turbine inlet. At the same time, the amount of additional working medium, heated in the recovery boiler in the peak mode, directly depends on the medium temperature at the hydrogen turbine outlet. Therefore, any increase of the temperature downstream the combustion chamber caused increased difference in the operating conditions of the HP and LP turbine parts in the two modes.

The power of the basic electric generator (i.e., the one driven by the steam turbine) remains almost unchanged when switching from one operating mode to the other. This is caused by the increased mass flow rate through the HP and LP turbine parts in peak mode, which compensates the shut-down of the MP part. This enables keeping the electric generator efficiency on a high level. Simultaneously, the coupling of the hydrogen turbine with a separate, peak-load electric generator enables the application of higher rotational speed, which leads to smaller turbine dimensions.

The obtained values of the system efficiency in both modes could be considered high. This concerns especially the efficiency of converting the hydrogen chemical energy (heat of combustion) into electric energy, for convenience called hydrogen efficiency. This notion has been introduced relatively lately – with the first research works on systems with two heat sources, one of which is a hydrogen-oxygen combustion chamber.

It has to be underlined here, that a combination of two heat sources is reasonable only if, in result of it, more labour (or electric energy) is obtained, compared to the same sources utilised separately. In order to evaluate the combination effect, one may try to compare the outputs directly, but this often unrealisable, mainly because of system complexity and incomparability. An indirect method method seems to be better, based on analysis of the utilisation efficiency regarding the higher-quality heat source. In this case, it is the hydrogen efficiency envisaged. It is defined, based on a virtual division of the system into two parts, connected with the particular heat sources, and a comparison of the performance when operating with the lower-quality source (NSG) and with both sources. The combination effect could be evaluated comparing the obtained hydrogen efficiency with the efficiency of the hydrogen turbine systems designed up to now (max. 59.9%).

Special attention was paid to the heat transfer conditions in the steam generator and the recovery boiler. Those conditions are shown in **Figure 60** and **Figure 61**, respectively.

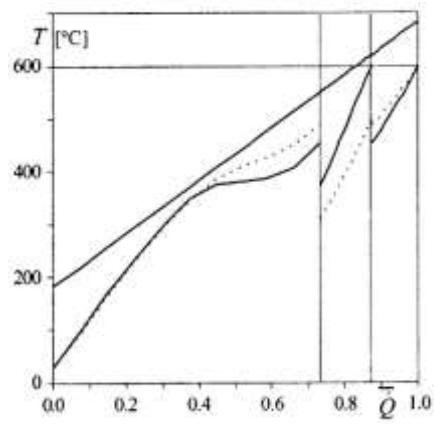


Figure 60 -Heat transfer conditions in the nuclear steam generator.

Solid line: Nighttime mode; Dashed line: Peak mode

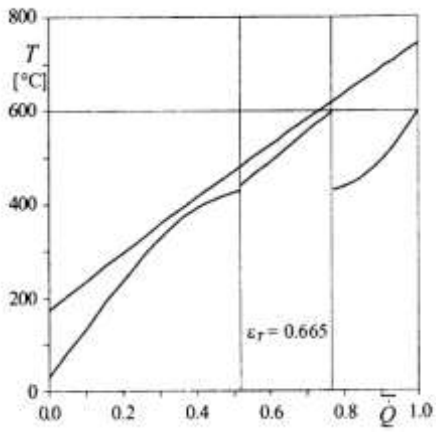


Fig. 8

Figure 61- Heat transfer conditions in the recovery boiler

Each of these heat exchangers consists of three stages, thye second of which is a steam reheater, and the others are feeding medium heaters. The temperature effectiveness of the particular stages is lower than the permissible (maximum) value. Its highest value corresponds to the recovery boiler's second stage and equals 0.665.

The comparison of the hydrogen efficiency and net electric efficiency of the system under consideration with the relevant values for hydrogen turbine systems designed up to now and nuclear power systems gives promising results. However, it does not give any idea about the overall efficiency of energy conversion from its primary to final form (in this case, electric). In the meantime, this is the quantity, which should in great extent decide about the rationality of application of hydrogen.

The overall energy conversion efficiency very much depends on the selected hydrogen production method. It seems that best results – both as a value of this efficiency and reduction of pollutant emissions – would be obtained by using thermochemical water dissociation cycles supplied with heat by HTR. However, on the present stage of this analysis, it was impossible to realise the needed calculations because of the lack of data about the performance of the most prospective thermochemical cycles supplied with heat of 750 °C (there are data about 850 and 950 °C).

7.5 Summary and conclusions

On the one hand, the society has to meet and solve the problems of: relatively high and potentially increasing organic fossil fuel prices; finite resources of those fuels; emission of pollutants; and energy security (mainly in countries importing energy carriers). Onthe other hand, the modern nuclear power technologies provide high safety, low energy cost, and practically infinite resources of nuclear fuel. These are the main factors of the recently observed return of the interest in nuclear power.

Among the most interesting solutions, providing application capabilities not only for direct power purposes, are the high-temperature reactors of generation IV. The research on them is far advanced in the United States and South Africa, and is quickly developing in the EU. In all projects the coolant is helium, and its maximum temperature is to reach 950 °C (or even more), which would enable their application also in hydrogen production processes. However, mainly for material reasons, temperatures of 950 or 850 °C appeared to be too high, so in the present analysis the limit was set to 750 °C.

The interest in hydrogen as a fuel is still very high. Unfortunately, the question of its production is omitted in the large majority of publications and projects concerning its application. The problem is not in the cost of this production, but in the overall efficiency of conversion of energy from its primary form to a final, usable one. It is caused by the fact, that the hydrogen production requires supplies of large amounts of energy, as this element exists on the Earth almost only in compound form. Its production and utilisation is rational only if in result the above-mentioned efficiency increases (and thus the consumption of organic fossil fuels and pollutant emissions decrease). As it was shown by the analysis of now applied or investigated hydrogen production methods, none of them secures fulfilment of this requirement.

Nevertheless, a possibility of rational hydrogen production may appear, although the above-mentioned requirement is not met. For example, heat from a HTR could be used for hydrogen production, next that hydrogen could be used as a fuel in a technology or as a substrate for a purpose, for which nuclear energy, or electricity made of it, cannot be used directly. Covering the daytime electricity demand peak using a peak-load hydrogen turbine is such a purpose (because of the specific technology and for safety reasons, the nuclear power reactors should operate with constant capacity and should be used for direct covering only of the basic demand). Thus, fully emission-free covering of the whole electricity demand could be secured, and the profits of such a solution will be surely higher than the losses from decreasing the overall energy conversion efficiency. In this concept, the hydrogen fuel plays the role of energy storage medium, thanks to which the energy from nuclear reactors could be concentrated and utilised during the peak demand.

Several projects of hydrogen turbine systems were developed up to now. They are all characterised by applying extreme temperatures (1700 °C) and pressures (supercritical, up to 35 MPa), in some cases realised at the same point, and by presence of a vacuum part with condenser. Therefore, it seems that their application as peak sources is technically impossible or inadvisable. The net electric efficiency of the Graz system (and its modified version), perceived as the most prospective, does not exceed 60% related to the heat of combustion, and this level is treated as a reference in this technology field.

The proposed and investigated system with peak-load hydrogen turbine enables a continuous operation of the high- and low-pressure components, and a quick and easy start-up and shut-down of the hydrogen part. The main idea is to apply two sources: a basic one, in the form of a continuously operating nuclear steam generator, supplied by a HTR; and a peak one, in the form of a hydrogen-oxygen combustion chamber. The hydrogen part of the system – combustion chamber, hydrogen turbine, and recovery boiler – is in fact located parallel to the steam turbine medium pressure part, and is a flow path alternative to it. Thus, a system capability is created to operate in two modes: basic (nighttime) mode, with one, nuclear heat source; and peak (daytime) mode, with two heat sources.

Detailed simulation-based investigation was realised using commercial software, incl. the preparation of an overall, consistent model of the system, preceded by preparation, verification, and integration of its particular calculation modules. The highest attention was paid to the heat transfer and expansion conditions in the relevant system components. The operating parameters of the of the components of the reactor primary loop (nuclear steam generator, and turbocompressor with no power generation) were determined. The determination of optimal solution regarding the system performance and technical realisability was an additional aim.

The basic assumptions and limitations, connected with the system operating parameters, secure the capability of its realisation today. First of all, this concerns the limitation of the hydrogen part parameters to medium pressures (between 50 and 1 bar), and a maximum temperature of 1500 °C, but also the rather conservative heat transfer condition requirements. The assumed values of the internal efficiency of the particular turbomachines are realistic. The continuous operation of the basic source secures a capability to keep the shut-down system components hot using small amounts of working medium, and thus their rapid start-up.

The results of the realised simulation and optimisation calculations seem to be very good. The system net electric efficiency in both operating modes is high (41.3% in nighttime mode, and 54.8% in peak mode). At the same time, the efficiency of conversion of the hydrogen chemical energy (heat of combustion) is on a very high level 63% and considerably exceeds the reference level (60%). The ratio of generated power in the two modes is also an important result: it equals 2.9, and this means that huge majority (more than 80%) of the electricity is generated during the daytime demand peak.

Further research should be done in order to determine the overall energy conversion efficiency. Data about the performance of thermochemical water dissociation cycles supplied with 750 °C heat will be needed for that purpose. Nevertheless, it should be expected, that the proposed system will secure a minor loss of overall efficiency, creating in return a capability of dispatchable, emission-free covering of the peak electricity demand.

8 Key design requirements and convergence with US-NGNP project

The Next Generation Nuclear Plant (NGNP) project has issued their key requirements that affect the design of the high temperature gas-cooled reactor (HTR) nuclear heat supply system in (Idaho National Laboratory - NGNP, 2010). These requirements derive from pre-conceptual design development completed to-date by HTR suppliers, collaboration with potential end users of the HTR technology to identify energy needs, evaluation of integration of the HTR technology with industrial processes and recommendations of the Next Generation Nuclear Plant Project Senior Advisory Group.

This section aims to maximize the design standardization and the convergence with the US-NGNP Alliance in the frame of the GEMINI Initiative (NC2I - NGNP Industry Alliance, 2014) by evaluating and adapting these requirements to a European case in regard to:

- Experience in previous cogeneration collected in (NC2I-R - D2.11, 2014) “Experience feedback from nuclear cogeneration”
- Licensing aspects identified in (NC2I-R - D3.11 , 2015) and (NC2I-R - D3.21, 2015)
- Economic and business modelling aspects (NC2I-R - D4.11, 2015)
- European potential end-users identified in (NC2I-R - D2.11, 2014)
- Selected design aspects for European nuclear power plant (European Utility Requirements, 2012)

8.1 General requirements

8.1.1 Design process and documentation

The design of a High Temperature Gas-Cooled Nuclear Reactor (HTR) shall be developed as a Standard Design which could be built in any of the European countries foreseen for deployment, with minimum changes.

The design process shall consist of two steps: the Standard Design, and the detailed and site-specific design activities. Site-specific design activities can only be performed when, following a commitment by an Owner to construct, a specific site has been selected.

As a minimum, the Standard Design (non site-specific), developed by the Plant Designer, should include:

- The basic design and layout for the Nuclear Island (NI),
- The standard site conditions (detailed in § 8.4 Standard site conditions),
- The functional requirements and specifications for systems and equipment,
- The safety case describing the list of Postulated Initiating Events, and the the provisions implementing the defense in depth principles, and an evaluation of the consequences.
- The list and classification of SSCs which have a role in the safety demonstration
- The interfaces with the remaining systems of the plant, especially the cogeneration unit
- The set of Codes and Standards used to develop the design,
- The identification of equipment from multiple qualified Vendors to be supplied according to specified interface requirements,
- The standard technical documentation of the design bases and resulting design.

A standardized design is consistent with the practice of European utilities in the frame of the European utility Requirements (EUR). It is recognized as a means of providing for improved plant designs with enhanced safety, shorter construction schedules, improved operability, all of which result in lower power generation cost.

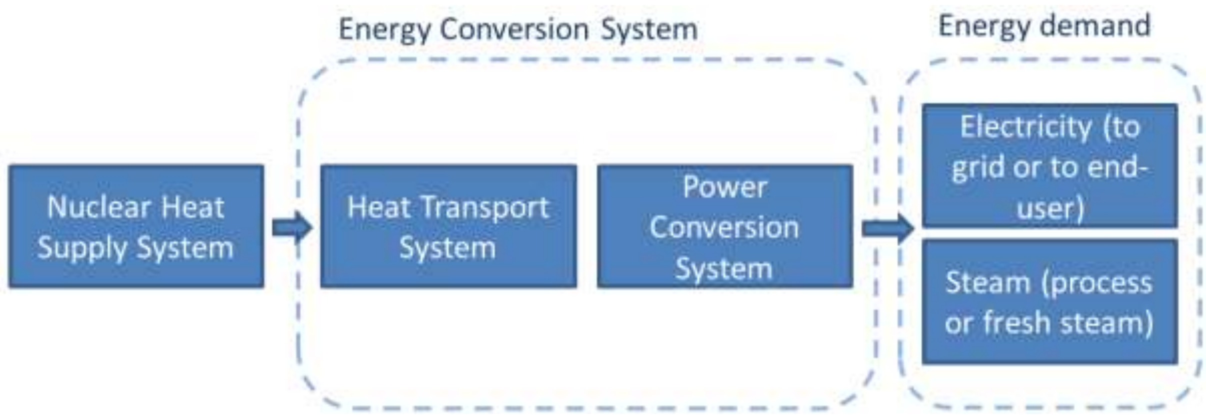
It is planned that engineering unique to the site is to be minimized due to the site-envelope basis used in the design of the Standard Plant. The latter includes design of systems and facilities unique to the site (pumping station, ground banks, etc.), any required modifications to the Standard Plant design, and design details of interfaces between the Standard Design and the site or equipment Supplier-unique conditions.

8.1.2 Reactor concepts

The HTR-NHSS shall be based on either a prismatic or pebble bed reactor concept using helium as the primary heat transport medium, TRISO – coated particle fuel, a graphite core and metallic reactor pressure vessel with dimensions and operating plant conditions that support a safety basis that does not rely on active safety related systems to maintain the reactor fuel within limits under normal, abnormal and accident conditions and to meet Top Level Regulatory Requirements (detailed in §8.1.6 Top level regulatory requirements) under accident conditions at the Exclusion Area Boundary of the plant.

8.1.3 Primary Helium circuit configuration

The HTR-NHSS primary helium circuit shall be physically separated from steam or high temperature gas supplied to the process by an intermediate heat transfer/transport system as shown in the following figure:

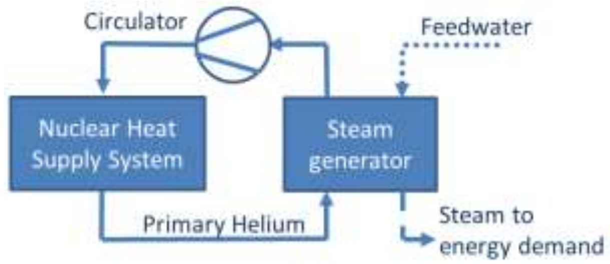


Experience from previous cogeneration (NC2I-R - D2.11, 2014) and licensing feedback (NC2I-R - D3.11 , 2015) has shown configurations where flammable gases were produced inside the reactor building and close to the second barrier. Such a configuration appears as a challenging on which seems no more coherent with present trend in licensing. Accordingly, even if technical provisions might ensure a sufficient prevention and protection of the reactor, the potential economic advantages of this scheme would certainly be jeopardized by the cost of the safety demonstration and subsequent operational constraints (in service inspection, radioprotection, etc.).

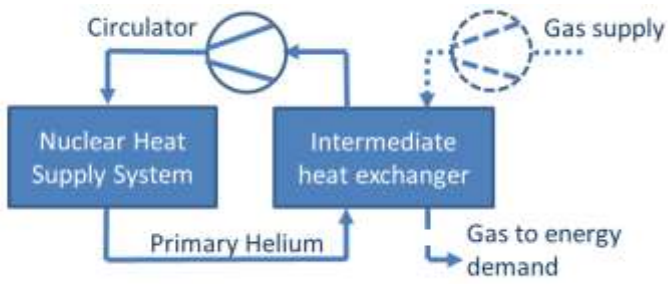
8.1.4 Interfaces with energy conversion systems

The HTR-NHSS shall be designed to be capable of interfacing with multiple potential energy conversion configurations as shown following:

Direct Steam Cycle: Energy is transferred from the reactor to the process using steam produced by a steam generator positioned in the primary helium circuit. The steam can be used, for example, to generate electricity using a Rankine cycle, supply industrial processes and for extraction of bitumen from oil sands.



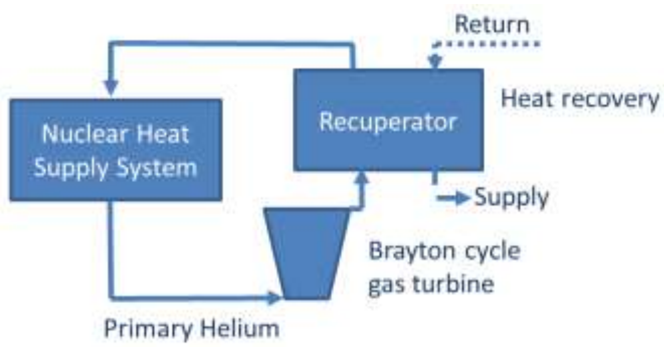
Indirect Process Heat Supply: Energy is transferred from the reactor to the process through primary helium to secondary fluid intermediate heat exchanger. The secondary fluids of initial designs have included helium and helium nitrogen. It is anticipated that advanced designs could use CO2 and liquid metals and molten salts. The secondary fluid can be used to supply a steam generator, support industrial processes, power gas turbines including a supercritical CO2 electric power generation system



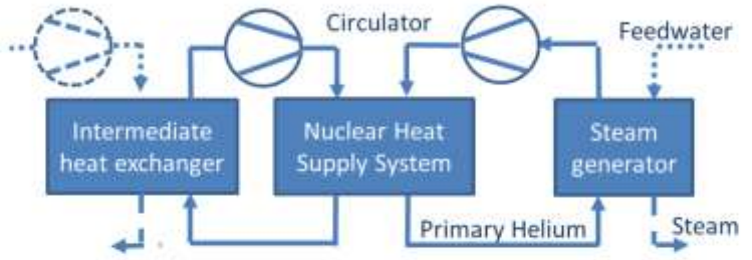
For configurations based on direct or indirect steam cycle, experience from previous projects collected in reports provided in the frame of NC2I and listed hereafter, shall be integrated in the design of the Interfaces with energy conversion systems.

- (G.Brinkmann, D.Vanvor & K.Verfondern, 2014) „Past Experience IHX and SSV“

Direct Brayton Gas Turbine Cycle: Energy is transferred in the forms of electricity and recovered heat. A Brayton cycle gas turbine generator is positioned in the primary helium circuit. The compressor of the gas turbine serves as the circulator as well as pressurizing the helium for expansion through the turbine. The recuperator recovers heat from the exhaust of the gas turbine for use in industrial processes



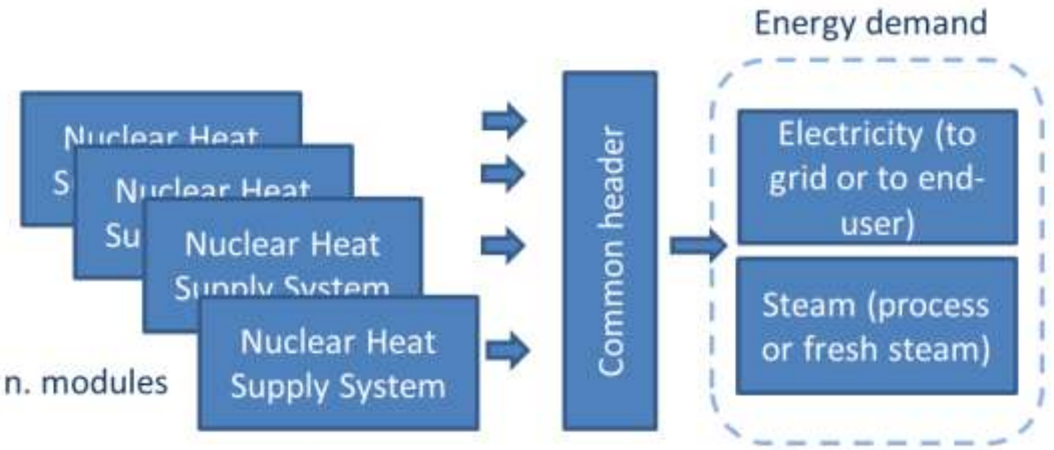
For configurations based on direct Brayton turbine cycle, experience from previous projects collected in reports provided in the frame of NC2I and listed hereafter, shall be integrated in the design of the Interfaces with energy conversion systems.

- (G.Brinkmann, D.Vanvor & K.Verfondern, 2014) „Past Experience Helium Turbomachines“	
Hybrid Cycles: Energy is transferred from the reactor to the process through primary helium to secondary fluid intermediate heat exchanger and a steam generator in either a series or parallel configuration. The steam and high temperature fluid are used to produce electricity and support industrial processes.	

8.1.5 Multiple module configurations

The HTR-NHSS shall be designed as a standalone module with the capability of being combined with other modules in a multiple module configuration with varying module configurations to meet energy demand requirements that exceed the rating of an individual module.

The configuration of the power generation unit may significantly vary the applicable requirements for grid connection as described in §8.2.2 Energy conversion ratings.



8.1.6 Top level regulatory requirements

The target for doses from direct radiation to the public during normal operation and incident conditions dose shall be 10 µSv/a per Unit. This target is independent from plant Rated Power.

This shall be assessed for the most exposed position or surrounding people:

- at 100 m from the most significant sources with an occupancy factor of 1/30 or,
- for the most exposed surrounding people with an occupancy factor of 1and with regard to all significant direct radiation sources
  Note that the last bullet can only be relevant for evaluation if people not under radiological control live or work closer than 300 m from any present direct radiation source. Examples of direct radiation sources are turbine buildings and intermediate storage of spent fuel, etc, at a site.

The values of distance and occupancy factor given are for the purpose of evaluation of the standard design with regard to direct radiation dose. They do not imply any particular requirements regarding control on ownership of land outside the site by the utility.

The ICRP 60 dose target for the general public is 1 mSv/a. Surrounding people includes staff and workers at the site that are not under radiological control.

8.1.7 Plant exclusion area boundary and emergency planning zone

Currently licensing requirements, regulations and national practices are generally based on radiological limits for accidents in terms of doses. Use of this type of criterion in this set of requirements would imply not only agreement on the values but also on dose evaluations methodology.

Currently there are significant differences in different countries for licensing analysis purposes in assumptions, e.g. on distance to site boundary, atmospheric transfer and meteorological conditions, deposition laws, transfer coefficient to food-stuffs, conversion factors to organ and body doses, assumptions about food banning, population distribution, etc. Therefore, for preliminary design assessment, it is proposed to adopt criteria in terms of releases.

These will have to be shown to be acceptable to the licensing authorities as consistent with their own national methodologies and regulations (as well as European or international regulations when available).

As required in (IAEA-SSR-2.1, 2012), the design of a nuclear power plant shall be such as to ensure that radiation doses to workers at the plant and to members of the public do not exceed the dose limits, that they are kept as low as reasonably achievable in operational states for the entire lifetime of the plant, and that they remain below acceptable limits and as low as reasonably achievable in, and following, accident conditions.

The design shall be such as to ensure that plant states that could lead to high radiation doses or large radioactive releases are practically eliminated and that there are no, or only minor, potential radiological consequences for plant states with a significant likelihood of occurrence.

The criterion for limited impact for LWRs is set so as to limit the societal consequences resulting from public health effects and contamination of soil and water. The objective is to minimize the requirements for emergency planning and off-site countermeasures. A standard design that meets the EUR criteria hereafter is expected to fit the specific environmental conditions that will be encountered on a majority of Western Europe sites as well as the country specific regulations.

The EUR criteria specified in (European Utility Requirements, 2012) have been established from conservative environmental data envelopes that cover a wide range of European sites. They envelop the country-specific regulations that exist at the time this revision of the text is published.

For a site with tougher environmental constraints it may be necessary to adapt the standard design. The plant designer may make sure its standard design meets the criteria with enough margins to avoid adaptation.

For Design Basis Accidents (DBA), the release targets for DBC 3 and 4 involve the two following design targets:

- No action necessary beyond 800m from the damaged plant,

- Very limited economic impact outside of the plant.

For Design Extended Conditions (DEC), objectives related to direct public involvement are identified and shall be considered in the design:

- No emergency protection Action beyond 800 m from the reactor during releases from the containment,
- No delayed action at any time beyond about 3 km from the reactor,
- No long term action at any distance beyond 800 m from the reactor
- Limited economic impact out of the plant

8.1.8 Plant worker exposure limits

The plant designer shall demonstrate that for the operational staff, the following objectives for annual effective doses, including doses due to all relevant activities like maintenance, repairs, equipment changes, refuelling, In-Service Inspections, etc. can be met:

Individual effective dose

Target for individual effective dose: 5 mSv/a.

This value is derivated from ICRP 60/91 which specify the following objectives:

- in one year < 50 mSv,
- Average over 5 years < 20 mSv/a.

Individual effective doses shall also comply with local regulations, if these are more stringent.

Collective effective dose

The collective effective dose shall be As Low As Reasonably Achievable. The target for annual collective effective dose averaged over the plant life is 0,5 man/Sv per module.

A target for annual collective effective dose is set for use in designing equipment and installations, and for formulating operating and maintenance rules. This target is already met by most operating nuclear plants in Europe.

8.2 End users requirements

8.2.1 Plant products

The HTR-NHSS shall have the capability to interface with energy conversion systems that supply energy in the following forms either individually or in combination:

- Electricity supplied to the regional grid and/or to support process operations
- Steam to supply steam turbine generators or for general use throughout the facility
- Process heat in the form of high temperature fluid to offset the emissions of greenhouse gases, (e.g., attendant to the burning of natural gas and waste gases in industrial processes)

Not all applications will require supply of all of these forms of energy; however, the fundamental plant design shall be capable of providing any mix of these forms as required by each specific application.

8.2.2 Energy conversion ratings

The HTR-NHSS shall be capable of supporting energy conversion systems with the following energy supply characteristics and demands:

Plant rating	Supplied Steam condition	Electricity requirements	High Temperature Fluid conditions
250 to 6900 MWth (with multiple module configuration, according to §8.1.5)	>275 b for supercritical applications, 170 b for subcritical applications 540 to 630°C	Up to 2500 MWe As a supply to the electrical grid a wide range is possible depending on the location.	700 to 925°C (Up to 750°C for the demonstrator)

The energy conversion ratings stipulated in the table above are consistent with the NGNP ones. However, it is important to note that the upper limit for energy production is not foreseen in Europe for short-term deployment, as:

- Most of the sites identified in (NC2I-R - D4.21, 2015) have a power level <750 MWth.
- Very few sites have an electricity need > 500 MWe
- Electricity to grid production brings limited benefits to the economic case, and are in competition with other sources (e.g. large reactors, renewables, fossil)
- In order to minimize technology risks, the plug-in market, steam class is targeted.

The requirements for unit sizing are necessary to limit the effects of the loss of one or all units of a plant with respect to load flow, primary reserve and voltage collapse. The maximum number of modules of one facility and the net capacity of one plant depends on the local grid conditions and is in scope of agreements with the Transmission System Operator (TSO).

Regulations relating to the capability to maintain constant active power output or to modulate active power output described in the Network code (ENTSO-E, 2015), shall not apply to power generating modules of facilities for combined heat and power production embedded in the networks of industrial sites, where all of the following criteria are met:

- The primary purpose of those facilities is to produce heat for production processes of the industrial site concerned;
- Heat and power generating is inextricably interlinked, that is to say any change of heat generation results inadvertently in a change of active power generating and vice versa; -
- The power generating modules are of limited to 75 MWe for Continental Europe and Great Britain, 30 MWe in Nordic.

Note: as mentioned in §2.3, a first project is expected to operate with a steam cycle up to 750°C for the purpose of process steam generation up to 600°C (also called Steam-class). On a longer term, evolutions with improved characteristics or different uses are expected.

8.2.3 Energy supply plant design

The energy requirements summarized herein shall be achieved by a HTR-NHSS.

8.2.4 Steam supply requirements

The HTR-NHSS shall have the capability of interfacing with energy conversion systems that supply steam with the following characteristics:

Steam Supply Pressure & Temperature Margins

The steam pressures and temperatures supplied to facility interfaces shall account for pressure and temperature drops along the facility header system to ensure that the pressures and temperatures at the end use meet requirements.

Steam Demand Variability

The HTR plant shall be designed to meet variations in steam demand from very low to maximum demand with demand characteristics as determined by the specific application and as specified in the sections below.

Steam Supply Excess Demand

Purchaser may exercise the option of increasing the steam demand for short periods of time. The notification and periods of increased demand shall be determined in the contract between the Supplier and the Purchaser.

In order to limit thermal fatigue and/or ensure safety margins during peak demand, use of back-up boilers might be investigated.

Steam Supply Over-Pressure Protection

Over-pressure protection shall be provided by the Supplier at the steam source.

Steam Supply Steam Chemistry

Steam supplied to the steam headers shall meet the requirements of the ASME guideline “Consensus on Operating Practices for Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers.”

Steam Supply Condensate Return and Makeup

The Purchaser shall return condensate to the HTR plant at a rate equal to the full steam demand plus makeup as required by the HTR plant.

This condensate shall be returned in a single header.

Return Condensate and Makeup Chemistry

The Purchaser shall provide specifications for the chemistry of the makeup and condensate returned from the steam supplied to the headers including the following as a minimum:

- pH
- Conductivity
- Total Organic Carbon (TOC) and turbidity
- Oxygen
- Pressure
- Temperature

The Supplier shall provide any additional conditioning equipment required to meet the specification for feedwater or makeup water to the Energy Conversion System.

Condensate and Steam Flow Metering

The Supplier shall provide certified steam and condensate flow metering. Steam flow metering shall be pressure and temperature compensated.

Steam Supply Interface Configurations

The Designer shall coordinate with the Purchaser to define the specific configuration of the interfaces with the Facility steam headers.

The following information shall be developed for each steam header and condensate return as a minimum: Headers Pipe Diameter, Schedule, Material, Insulation and Flange Design for the supply and return

8.2.5 Electric supply requirements

The HTR-NHSS shall be capable of interfacing with energy conversion systems that supply electricity to the facility and to the regional grid as described in the Network code (ENTSO-E, 2015). Note: the Network Code on Requirements for Generators was adopted in 2015 by Member States. It will now go through scrutiny from the European Parliament and Council.

Electric Power Supply Interface Configurations

- The electrical supply shall be designed to be compatible with the facility electrical distribution system and the regional grid.
- The designer shall develop the configuration and design requirements for the electrical connection between the generator and low voltage taps on the facility distribution transformer and the regional grid transformer.
- The Supplier shall provide the transformers and power lines as required to connect with the facility distribution system and the regional grid.
- The connection of the units of a plant to the busbar sections of the Extremely High Voltage (EHV) grid substation associated to the plant shall be such that single electrical grid failures do not lead to simultaneous loss of more than one nuclear power plant (NPP) unit.

Electrical Supply Characteristics

Requirements applicable to connect generators to the grid are detailed in Network Code (ENTSO-E, 2015). The power unit configuration (e.g. several power generating modules in a power generating facility) may lead to different requirements, to be agreed with the local Transmission System Operator.

The design shall comply with the following aspects:

- Compatible with the European electrical grid
- Distribution Voltage, KV (Facility)
- Distribution Voltage, connection point at 110 kV or above.
- Phase
- Frequency, hz (When islanded)
- Power Factor
- Facility Distribution Transformer, KVA
- Regional Grid Transformer, KVA

Electric Power Supply Power Quality

- The frequency and other properties and characteristics, (e.g., phase voltage imbalance) shall be as required by the regional electricity supply utility for operation on its electrical system.
- Power factor correction shall be provided by the Supplier.

8.2.6 High temperature fluid supply requirements

The HTR-NHSS shall be capable of interfacing with energy conversion systems that supply high temperature fluid via a Secondary Fluid Circuit to selected processes in the facility.

Configuration

The Secondary Fluid Circuit shall be isolated from the HTR-NHSS Primary Helium Circuit.

Circulator and Pump Designs

The secondary fluid shall be compatible with standard circulator and pump designs.

Secondary Fluid Circuit Purification Systems

A means to remove corrosion products and foreign objects shall be positioned in the secondary circuit prior to entering the circulators or pumps. If required the Purification system shall also remove radionuclides transported or activated from the Primary Helium Circuit, (e.g., tritium).

High Temperature Fluid Supply Temperature Requirements

Supply Temperature at Header, 700 to 925°C

Return Temperature at Header, 325 to 520°C

Note: “steam-class” is the target market for a demonstrator. However,

High Temperature Fluid Supply Physical Properties

The working fluid shall be compatible with the materials of construction in the HTR-NHSS.

Primary Helium and Secondary Fluid Circuits at all anticipated normal and abnormal operating conditions. The Designer shall provide suggested ranges for fluid physical properties based on compatibility with the designs and materials of construction of the Primary Helium and Secondary Fluid Circuits.

High Temperature Fluid Chemistry

The Designer and Purchaser shall determine the required fluid chemistry conditions to satisfy the HTR-NHSS, the Secondary Circuit and the process requirements to include as a minimum:

- Oxygen [upper and lower limits TBD]
- Nitrogen < [TBD] ppm
- Moisture [upper and lower dew point TBD]
- Hydrogen < [TBD] ppm
-
- Carbon Dioxide < [TBD] ppm

High Temperature Fluid Supply Interface Configuration

The Designer shall coordinate with the Purchaser to define the specific configuration of the interfaces with the process. The following information shall be developed for interface as a minimum:

Pipe Diameter, Schedule; Material; Insulation & Flange for the supply and return

8.2.7 Performance requirements

Normal and Emergency Demand Transients

When operating at power, the HTR Plant shall be capable of responding to the following process transients without interruption or degradation of supply:

- Steam Headers

  Step Change: ±10%

  Maximum rate of change: 20% / min decreasing

  Maximum rate of change: 20% / min increasing

- Electric Power

  Step Change: ±10%

  Maximum rate of change: 10 MWe/min decreasing

  Maximum rate of change: 10 MWe/min increasing

- High Temperature Fluid

Step Change: ±10%

Maximum rate of change: 20% / min decreasing

Maximum rate of change: 20% / min increasing

Full Load Rejections

The Plant shall be capable of accepting a full load rejection from either steam, electrical or high temperature gas demand.

Partial or Zero Demand

Plant shall be able to accept zero steam flow demand and/or zero power demand, and/or zero high temperature gas demand. If all demand is lost temporarily the HTR-NHSS plant shall remain capable of meeting demand as it is restored within a maximum time period to be supplied by the Designer.

Total Demand

Plant shall be capable of accommodating coincident average steam, electrical and high temperature gas demand.

Loss of Condensate Return

Plant shall be capable of operating with zero condensate return from Purchaser for 2 full power days.

8.2.8 Availability

The average required supply of steam to the steam headers, high temperature gas to the gas headers, and electrical power generation to the electrical interconnections with the grid shall be available 100% of the time (24 hours a day, 7 days a week, 365 (366 in leap years) days per year). The N-xd availability requirements for the plant will vary according to the specific application. The most stringent identified to-date requires meeting the availability requirements with two of the nuclear heat supply modules out of service.

As availability factor is one of the most significant factors influencing the economics of project, the design shall consider following dispositions:

- The reactor Protection System and the engineered safeguards actuation system shall be designed so that:
    - the plant can be operated for a prolonged time at full power with one protection channel in test or by-passed (because of failure or other reasons),
    - With one channel in test, one subsequent single failure will not cause a plant trip.
- Systems design shall make provisions for testing which do not disturb or complicate plant operation.

    - Testing features shall be designed to account for a single failure in those systems being tested, or in connected systems, or a single credible Operator error (such as placing the wrong channel in test), without causing a plant trip.
    - Where control logic instrumentation is provided, continuous fault-tolerant self-testing methodologies shall be used.
    - Testing shall be done on the minimum acceptable frequency that ensures safety and operability.
- For the testing of passive systems, the designer shall propose the scope of the tests and methodology to perform them in order to demonstrate their performances

8.3 Design requirements

8.3.1 HTR-NHSS lifetime

The HTR-NHSS shall have a plant design lifetime of 40 to 60 years (calendar).

The economic study (NC2I-R - D4.11, 2015) shows a limited benefit for the economic case, of an extended lifetime. Therefore, the cost-benefit of additional design features to improve the design lifetime beyond 40 years shall be evaluated on the basis of specific end-user requirements (e.g. transients, load following abilities…).

The Designer shall list all major components and equipment which are not designed to be replaced during plant lifetime, and specify the Design Lifetime of the replaceable components and equipment.

The design of the plant shall be optimised in order to meet this plant lifetime requirement. This optimisation will take into consideration the following:

- All major plant components and equipment which are not replaceable shall be expected to meet the specified design life,
- The Designer shall define the fluid system design transients which should represent umbrella cases for operational events postulated to occur during the plant design Lifetime,
- These transients should be considered to be such magnitude and/or frequency to be significant in the component design and fatigue evaluation process,
- Pertinent variations in the fluid pressure, temperature and flow should be determined by associated transient analyses and used to describe the transients from the component design point of view,
- The plant shall be designed to enable expeditious replacement of all operational components and equipment, especially heavy components, except the Reactor Vessel.
- There shall be a plan for replacement of those components which may be subject to obsolescence, or to avoid early failure due to fatigue,
- This plan for replacement, refurbishment or repair shall ensure that the design life of the plant is achieved at minimum cost and will be submitted to the owner for early approval,
- Where appropriate, provision shall be made to allow Inspection, maintenance and replacement of seals between different buildings.

The above shall be achieved without impact on the availability requirements of the plant.

In order to support the design life, the Designer shall take account of the following:

- The development of a Preventive Maintenance program which makes use of condition monitoring of components, systems and structures, where it is shown to be cost effective,
- Reduction of the frequency and magnitude of plant transients,
- Provision of adequate instrumentation systems to monitor and record significant transients over the plant's lifetime,
- The location of equipment to avoid, or minimise the frequency of exposure to adverse or life-limiting environments,
- The initiation of a lifetime records system which includes provision for information on design life, environmental limits, and acceptance criteria and computerised collection of related parameters.

8.3.2 Reference nuclear fuel

Reference fuel shall be Tri-Isotopic (TRISO) coated particle fuel, LEU-based (UCO or UO2) with an enrichment limited to <20.0% (in mass) and with a peak burn-up limited to 20% Fissions per Initial Metal Atom (FIMA).

8.3.3 Functional containment

The HTR-NHSS shall apply the concept of a “functional containment”. The functional containment is comprised of the kernel and coatings of the TRISO coated fuel particles, the fuel matrix and fuel element graphite, the primary circuit, and the reactor building. Each of these barriers contributes to limiting the release of radionuclides to the environment to meet the top level radiological criteria as defined in §8.1.6 Top level regulatory requirements

8.3.4 Steam & High temperature fluid radionuclide content

Methods shall be developed and implemented to control the concentrations of radionuclides in steam and high temperature fluids produced by the HTR such that the levels of radionuclide that could be transported from the primary helium circuit or activated by exposure to the helium primary circuit do not exceed those that appear in steam and high temperature fluids produced by non-nuclear energy sources, (e.g., the burning of natural gas or waste gases).

8.3.5 Passive residual heat removal

The HTR-NHSS shall be designed to provide passive residual heat removal to the environment that maintains fuel temperatures and core and plant structures, including concrete, within acceptable limits when neither the Primary Helium circulator nor the Shutdown Cooling System is available under normal and depressurized conditions.

8.3.6 Neutron control element reactivity

The neutron control elements shall be designed to provide sufficient negative reactivity to shut down the reactor and maintain it in subcritical condition for any state while compensating for the worst positive reactivity insertion.

8.3.7 NHSS protection system

The NHSS Protection System shall maintain plant parameters within acceptable limits established for Design Basis Accidents.

8.3.8 Shutdown cooling system

The HTR-NHSS shall include a Shutdown Cooling System to transport core residual and decay heat from the reactor system to the environment when the reactor system is shut down and the Primary Helium circulator is not operational. The Shutdown Cooling System or equivalent shall be operational whether the Helium Primary Circuit is pressurized or depressurized and during refuelling, maintenance and repair activities.

8.3.9 Helium service system

A Helium Service System shall be provided to maintain the Primary Helium Circuit inventory, store helium during depressurizations, provide backup supply of helium, and remove impurities including dust, oxidants, and radionuclides from the Primary Helium Circuit

8.3.10 Radioactive waste and decontamination system

A Radioactive Waste and Decontamination System shall be provided for the following functions:

- Monitoring, collecting and processing radioactive (or potentially radioactive) liquid and gaseous wastes, including various forms of solid waste generated within the plant.
- Storing radioactive (or potentially radioactive) liquid and gaseous wastes, including various forms of solid waste generated within the plant.
- Providing equipment to remove radioactive surface contamination from components, as necessary, to facilitate control and minimize migration of radioactive contamination and to limit personnel exposure to radionuclides.
- Ensuring that all radioactive wastes generated within the facility shall be collected, monitored, treated, and processed onsite prior to shipment offsite.

8.3.11 Fuel handling system

The HTR-NHSS shall include a Fuel Handling System to remove and replace fuel from the reactor core, prepare new fuel for use in the reactor core and store spent fuel.

8.3.12 Fuel inventory control

The HTR-NHSS shall incorporate Nuclear Fuel Inventory Control design features facilitating implementation of material control and accounting procedures that are sufficient to enable the operating organization to account for the special nuclear material in its possession.

8.3.13 Single integrated control room

The HTR-NHSS design shall permit the operators to take control of multiple modules including support processes from within a single integrated control room using the manual mode at any time for conditions of all NHSS in operation, one or more modules in refuelling, one or more modules under construction, one or more modules being decommissioned.

Lesson-learned from past project (INL/EXT-10-19329, 2011) and current operation feedback show that human error is a major cause of events during operation. HTR development program shall be based but not limited on the expectations of the Human Factors Engineering Program Review Model as described in (NUREG-0711 , 2004) and HFE related European standards like (IEC 60964, 2009).

The integration of HFE principles into the plant design process shall ensure a safe and reliable plant operation:

- To enable plant operating personnel to perform their tasks especially to be able to operate the plant in accordance with the plant safety goals
- To ensure high availability and performance of the plant by a plant design that reduces the possibility of human error
- To enable plant operating personnel to detect possible deviations from normal operating conditions and to provide applicable features to allow them to cope with that deviations
- To develop plant design, that supports the plant operating personnel to perform their tasks considering human strengths and covering human limitations
- To ensure that the design reflects state-of-the-art human factors principles as required by law
- To satisfy other regulatory requirements related to controls and displays to be used by operators
- To consider human operations related lessons learned in the plant design

8.3.14 Heating, ventilation and air conditioning functions

Ambient conditions for the correct operation of systems which perform Safety Functions and non-safety functions (e.g. temperature, pressure, relative humidity and cleanliness) and for personnel accessibility shall be maintained by:

- Removal of heat generated by equipment and holding air temperatures within satisfactory limits (notably to prevent freezing),
- Renewing air,
- Ventilating rooms containing inert gases or noxious gases without impairing the capability to control radioactive effluents,
- Maintaining an appropriate direction of air flow between different areas,
- Providing uniform air temperatures within rooms,
- Reducing the concentration of radioactive gases and aerosols,
- Maintaining relative humidity of the air, if required,

- Functions necessary to limit the possible release of radioactive substances into the external environment,
- Functions necessary to maintain air conditions suitable to personnel and correct operation of equipment,
- Systems necessary for venting of escape routes.

The Main Control Room (MCR) shall remain habitable during all Design Basis Conditions (DBC) and Design Extended Conditions (DEC) even in the event of

- Smoke,
- Explosive and toxic gases from internal origin or resulting of an event in the vicinity of the plant.
- Radioactive contamination of the external environment,

If the Designer proposes the use local controls instead of remote controls, the Designer shall demonstrate that the time available and the nature of the controls (accessibility, communications needed, etc.) enable to reach and maintain in a Cold Shutdown State.

The Emergency Preparedness Centre at the site shall be provided for emergency preparedness and emergency management functions during Accident Conditions, DEC and other emergency situations.

A Technical Support Centre near MCR shall be provided for the emergency staff who would work there in the event of an emergency to support the activities of plant operators.

8.3.15 Backup DC and AC power

A Direct Current (DC)/Uninterruptible Power Supply (UPS) System shall provide a stored energy source for the all plant DC loads. Redundant sources of reliable A/C power shall be provided to support required A/C loads

8.3.16 In-service inspection

Structures, Systems and Components (SSC) which perform Safety Classified Functions shall be designed for adequate reliability. Provision shall be made for monitoring, testing, sampling and Inspection, to assess ageing mechanisms predicted at the design stage and to identify unanticipated behaviour or degradation that may occur in service.

Except as provided for below, they should also be designed to be calibrated, tested, maintained, repaired and inspected or monitored with respect to their functional capability throughout the life of the plant. The design shall be such that these activities can be performed to standards commensurate with the importance of the Safety Functions to be performed, without undue exposure of the site personnel to radiation. The design of components and layout shall be such to favour In-Service Inspection (ISI). The Designer shall provide a description of activities in this area which are required to maintain the plant's reliability and integrity.

If a Safety Classified SSC item cannot be designed to be tested, inspected or monitored to the extent desirable, then a robust technical justification shall be provided that incorporates the following approach:

- Other proven alternative and/or indirect methods such as surveillance testing of reference items or use of verified and validated calculation method shall be specified.
- Conservative safety margins shall be applied or adequate and appropriate safety precautions shall be taken to compensate for potential unanticipated failures.

In the design of the plant, equipment unavailability shall be taken into account. The impact of this unavailability on the anticipated maintenance, test and repair work on the availability of each individual Safety System shall be included in this consideration. If the resultant availability is such that the system no longer meets the criteria used for the design, the plant shall be shut down or otherwise placed in a safe state unless the component temporarily out of service can be replaced or restored within a specified time. This time and the actions to be taken shall be defined in each case on the basis of probabilistic considerations and engineering judgment.

The frequency of testing necessary to meet the required availability shall not be excessive in order to limit the number of demands on systems.

There shall be provisions, including procedures, to check the operability of equipment after maintenance and testing. The design should allow any necessary testing of equipment with the system on-line, with minimum chance of adversely affecting safety.

Defining the requirements for Inspection, monitoring, testing and maintenance over the plant's lifetime will be an important aspect of reliability assurance, especially by taking into account all ageing relevant impacts and by documenting all ageing relevant information. (This includes the consideration of physical ageing of SSC resulting in degradation of their performance characteristics).

It also contributes achieving a high availability factor, identified as significant for the economics of the plant in (NC2I-R - D4.11, 2015).

8.3.17 Preventive and predictive maintenance

Elements for establishing a Preventive Maintenance (based on performance experience) and Predictive Maintenance (based on expected behaviour) programme shall be provided by the Designer to ensure optimum performance and reliability of plant equipment.

The elements shall be established taking into account the plant design lifetime.

These elements shall enable the plant operator to implement maintenance programmes based a systematic evaluation approach for developing or optimising a maintenance programme, so-called Reliability Centred Maintenance (RCM) that utilises a decision logic tree to identify the maintenance requirements of equipment according to the safety and operational consequences of each failure and the degradation mechanism responsible for the failures.

Preventive Maintenance programmes shall be based on appropriate Inspection and maintenance codes, such as Inspection and maintenance codes from American Society of Mechanical Engineers (ASME)

8.3.18 Seismic design requirements

Seismic Category I structures and equipment (required to fulfil Safety Functions during or after an earthquake) shall be qualified seismically by tests or analysis to a sufficient extent to ensure that the reactor can be brought and maintained in a Safe Shutdown State (SSS) and that all necessary Safety Functions are fulfilled.

This shall include events which are credible as a consequence of, or coincident with, the earthquake (Examples of such credible event, as a consequence, are Loss Of Offsite Power (LOOP), flooding and fire in the plant…)

The plant behaviour should also be analysed assuming damage to non-seismic structures and components. Structures which provide non-Safety functions shall be designed to not impair Safety functions.

Design values for a standard European site are given in §8.4.1 Seismic hazard

IAEA Safety Guides, such as (IAEA-NS-G-2.13 , 2009), (IAEA-NS-G-1.6, 2003) and (IAEA-SSG-9, 2010) document the best practices in evaluation of seismic hazard and design requirements.

8.3.19 Aircraft impacts

HTR-NHSS plant shall be designed and constructed with consideration of direct and indirect effects of aircraft impact, in particular:

- effects of direct and secondary impacts on mechanical resistance of safety structures and systems required to bring and maintain the plant in a safe state after aircraft crash,
- effects of vibrations on safety structures and systems required to bring and maintain the plant in a safe state after aircraft crash,
- Effects of combustion and/or explosion of aircraft fuel on the integrity of the necessary structures and systems required to bring and maintain the plant in a safe state after aircraft crash.

Intentional aircraft crash is an extreme event which can only happen if several security defence layers have been breached. A probabilistic approach for this hazard is subjective and unrealistic. Therefore a deterministic approach is required.

8.3.20 Explosion and pressure wave

Consideration shall be given to the possibilities of dangerous substances affecting the safety of the plant since the reactor site may be in the proximity of installations where significant quantities of such substances may be used or stored, or a route along which such substances may be transported. Examples from previous projects are listed in (NC2I-R - D3.11 , 2015).

The Standard Plant design shall incorporate provisions to withstand the effects of an external explosion which gives a pressure rise. The effect of the reflection factors should be taken into account.

Criteria appropriate to each site will be specified when necessary by the Owner, taking into account the amount and type of hazardous substances, distance from the reactor, and topography of the countryside, actual and planned industrial development around the site, prevailing winds and other relevant local factors.

8.3.21 Decommissioning and decontamination

The design of the HTR plant shall incorporate features consistent with decommissioning and decontamination best practices. The Initial Decommissioning Plan (IDP) shall be written assuming that the plant will be finally shutdown after having been in operation for its design lifetime.

On multi-Unit sites, the different decommissioning plans shall take into account the resulting common buildings and systems (The maintainability of the functions of some common buildings and systems such as access building, radwaste systems... may be impacted by the decommissioning schedule and layout of each unit.

Eventual presence of other reactor Units* and the resulting common buildings on site will be taken into account for the different Decommissioning* plans.

The designer shall work out a feasibility study as part of the first Initial Decommissioning Plan, which shall:

- Demonstrate that decommissioning based on the layout of the plant and on the maintenance and repair provisions is feasible using proven engineering techniques available at the time of the study,
- Demonstrate that the decommissioning can be carried out safely while considering the ALARA principle,
- include an estimation of the inventory and distribution of radionuclides throughout the plant based on the source term,
- Present estimates of the amount and type of waste which is to be disposed of during the decommissioning of the plant, including waste which can be released and/or recycled,
- Show the expected personnel doses during decommissioning,
- Provide sufficient information at the design stage to determine a first estimate of the decommissioning cost.

8.3.22 Advanced fabrication and construction techniques

Advanced techniques, such as the use of factory or field-fabricated and assembled modules containing portions of systems and/or structures, shall be utilized (as appropriate) to reduce erection costs and schedule risks and to enhance quality control.

The design of buildings and equipment shall facilitate plant construction and the installation, repair, and replacement of equipment.

8.4 Standard site conditions

This section addresses site and plant-related criteria that are applicable to all buildings, structures, systems and equipment, of the Nuclear Island. The site conditions envelope is considered to be acceptable for most locations in Europe.

External hazards and environmental conditions shall be taken into account by the Designer. The conditions are subdivided into natural and man-made events. The values to be assumed by the Designer for the design of the Standard Plant (frequency and magnitude) are specified in this chapter.

In addition hazards that could arise within the plant boundary shall be taken into account for the design of the Standard Plant. Specific attention is paid to the establishment of the seismic conditions and the design of structures to meet these criteria. Site proximity Hazards (e.g. related to the cogeneration plant or End-user plant which are to be taken into account, are also outlined.

8.4.1 Seismic hazard

The designer is required to design a standard design suitable for the majority of sites in Europe with minimal changes being necessary to meet country-specific and site-specific requirements.

The standard design will be required to envelop a range of soil properties.

Seismic Category I Structures, plant and equipment shall be designed against a suite of vibratory ground motions, which together define the Design Basis Earthquake (DBE). The free-field zero-period horizontal acceleration at ground level (PGA) of the DBE is set at 0.3g and is associated with three ground motion response spectra.

The minimum level at which a shutdown is required to evaluate the condition of the plant following an earthquake shall be 0.1g PGA.

8.4.2 External air temperatures and humidity conditions

For the Design Basis Conditions (DBC) the design shall be adaptable (the layout should not be changed) to the following range of air temperatures.

- long-term base temperature -25°C to 32°C (extreme temperature for periods > 7 days),
- short-term daily temperature: -30°C to 37°C (extreme temperature for periods of between 6 hours and 7 days),
- Instantaneous temperature: -35°C to 42°C (extreme temperature for a 6 hour period).

The envelope defined by the maximum and minimum temperatures is based on typical conditions in Europe. Given the current trends in climate change, detailed studies with a return period of 10^{-4} per year during the expected lifetime of the plant might be used as basis.

The Standard Design shall be able to deal with the following range of maximum external humidity conditions, for the DBC:

- In summer, 60% relative humidity at 37°C (dry bulb),
- In winter, 100% relative humidity at -25°C.

The Standard Design shall deal with the following:

- The building layout shall be designed to accommodate cooling systems capable of operating within the temperature ranges specified,
- The equipment itself, e.g. pumps and heat exchangers, shall be sized to suit the range of conditions appropriate to each particular site.

For the envelope defined by the maximum and minimum long-term base temperatures, the buildings and plant shall be designed for continuous performance within their design temperature ranges.

For the temperature envelope between the long-term base and short-term daily temperatures, both maximum and minimum, the buildings and equipment shall be designed for continuous performance, but normal temperature ranges may be exceeded where this does not impact the safety or the operability of the plant.

As a minimum, Safe Shutdown equipment needed to bring the plant to and maintain it in Safe Shutdown State shall remain operable. No systems shall freeze; operational areas shall not be subject to excessive high and low temperatures.

For the temperature envelope between the short-term daily and instantaneous temperatures, both maximum and minimum, the buildings and plant shall be designed such that the plant can be maintained in Normal Operation* and no physical damage is sustained.

The Designer shall take steps to ensure that there is no "cliff edge effect" if the instantaneous temperatures is exceeded.

8.4.3 Wind and wind-generated missiles

For the DBC the design shall be adaptable (the layout should not be changed) to the following ranges of wind velocity:

- Basic wind speed up to 43m/s,
- Extreme wind speed up to 70m/s.

The Standard Design does not take into consideration hurricanes or tornadoes. For specific European sites, hurricanes or tornadoes could only be taken into account if their probability of occurrence is of a value which affects the Core Damage frequency.

For the design of buildings, it should be assumed that these wind speeds are at a height of 10m above the ground level of the site.

Structures housing systems and equipment which are required to bring the plant to and maintain it in Safe Shutdown State or for protection against unacceptable release of radioactivity from stored fuel and radioactive waste shall be designed to withstand loadings based on the extreme wind speed. The same extreme wind speed shall also be applied to safety equipment which is directly exposed to the wind.

SSC which provide Non-Safety Functions shall be designed to withstand the basic wind speed and ensure that their failure under extreme wind conditions does not impair Safety Functions.

Wind-generated missiles

Structures housing systems and equipment which are required to bring the plant to and maintain it in Safe Shutdown State or for protection against unacceptable release of radioactivity from stored fuel and radioactive waste shall be designed to withstand wind-generated missiles (typically cladding panel, both insulated and uninsulated aluminium, scaffolding plank, scaffolding pole...).

Based on the plant design and its layout and using a probabilistic approach, the designer shall make an assessment of the missiles likely to occur and their positions of impact and demonstrate that the plant can reach a Safe Shutdown State.

8.4.4 Cooling water temperatures

For the Design Basis Conditions, the design shall be adaptable (the layout should not be changed) to the following range of water temperatures at the intake:

- Seawater : -0,5°C to 30°C,
- River: 0°C to 30°C.

In this range of values the designer shall choose the maximum Standard Design value, the minimum Standard Design value and the extreme maximum Standard Design value, while making sure they meet the specific requirements of the owner.

As these temperatures are approached in a gradual way the operators shall be given adequate information and alarms with means to manually initiate mitigating actions to reach a Safe Shutdown State, if there is no automatic action initiated by its overstepping (It may be assumed that the extreme maximum cooling-water temperature can be anticipated by a period of 12 hours).

The plant shall be adaptable to make it capable of full-power operation for cooling water temperatures up to the specified maximum Standard Design value.

For temperatures between the maximum Standard Design value and extreme values, the plant shall be designed to be capable of reaching a Safe Shutdown State and being maintained in that condition until temperatures fall.

The building layout shall be designed to accommodate cooling systems capable of operating with cooling-water intake temperatures up to maximum or extreme values according to required design basis function.

8.4.5 Precipitation and External Flooding

External flooding

The plant shall be protected from external flooding. The methodology to be adopted for calculating conditions shall be specified. This methodology will take into account aspects such as flooding, dam rupture and tidal effects.

Rainfall

The plant shall be designed to withstand:

- A design-basis rainfall depth of 100 mm in one hour,
- A rainfall depth of 400 mm in 24 hours.

Snowfall

The Standard Plant shall be designed to withstand a design-basis level snow loading of 0,9kN/m2. This loading shall be increased by 0,75kN/m2 where man-access is possible.

Accumulation of snow by drifting on buildings which house Safety Systems shall either be prevented or suitably increased loadings shall be taken into account in the design.

All equipment and in particular Safety-Category I Structures, shall be capable of adaptation, without changing the layout of the Standard Design, to withstand an upper limit of 1,5kN/m2 excluding allowance for man-access.

Specific site may require more severe design conditions. The Plant owner will specify the particular site requirements.

Measures shall be taken to prevent blockage of intakes of HVAC, diesel generators or other systems, which rely on an air supply to maintain their function.

Lightning

The design-basis lightning levels that should be used for the protection of buildings are consistent with European Union (EU) Standard Euronorm (EN) V 61024:

- First stroke: 200 kA; 10/350 µs.
- Second stroke: 50 kA; 0,25/100 µs.

Electrical equipment shall include protection against surges resulting from lightning strikes on electrical transmission lines.

Drought

The ability to perform a Safety Function shall not be affected.

The drought conditions applicable to a particular site will be specified by the plant owner. It is likely that these conditions will occur gradually, thus restricting water supplies and resulting in restricted power output or plant shutdown as necessary.

8.4.6 Other natural hazards to be considered

The following list (not exhaustive) should be considered and the necessary steps taken to protect the safety of the plant:

- Water pollution:
- Blockage of cooling-water intakes by ice, debris, seaweed and marine life e.g. jellyfish,
- Reduced flow due to algae and marine growth,
- Loss of equipment performance due to oil or other suspensions/emulsions entering the cooling-water system,
- Corrosion of system components.
- Fish:
- Blockage of cooling-water intakes (if required in the safety demonstration).
- Coastal erosion:
- Rapid erosion by the sea.
- Insects:

- Blockage of intakes of HVAC, diesel generators or other systems which rely on an air supply to maintain their function.
- Sandstorm:
- Blockages of air intakes.
- Rodents:
- Loss of electrical equipment by, for example, shorting as a result of gnawing and destruction of insulation materials by rodents.
- Snow and freezing rain:
- Blockage of air intakes.

Additional information is provided in (IAEA-SSG-18, 2011), (IAEA-NS-G-1.5, 2003), (IAEA-SSR-2.1, 2012)

9 Conclusion

The aim of this report was to propose key requirements for the design of an HTR for cogeneration purposes, based on:

- Economic aspects of cogeneration
- End-user needs identified in the mapping of European sites
- Current or future applications with high energy consumption
- Convergence with the US-NGNP program

Economic studies were performed to identify the key parameters for defining requirements for a high-temperature nuclear cogeneration plant. Delivering heat and power to chemical complex ensure the most profitable case for near-term deployment.

Different end-user configurations have been tested, with the basis of energy-intensive user needs identified in the mapping of European sites. Most of the sites have thermal needs lower than 700 MWth, and more than the half have thermal needs lower than 250 MWth.

For chemical complex with a thermal need lower than 200 MWth, profitability is challenged under the current market conditions. Therefore, additional revenues shall be considered though additional load (e.g. supply district heating needs in the vicinity of the chemical complex) or valuation of parameters not considered in the study (e.g. energy independence..).

A preliminary Thermal/Electricity ratio, based on the conditions of Chemelot site (Netherland) was evaluated between 2,75 and 3.

Other applications have been evaluated:

Coal-To-Liquid process, based on the conditions of Secunda West plant (South Africa) and potential improvement of the current processes, is hardly competitive with the current market conditions. Substitution of coal generated process steam and electricity offers the best opportunity for nuclear cogeneration, when compared to all other coupling configurations. However, the challenge remains its high cost and the impact of such on the profitability of the conventional CTL route.

Advanced process operating at higher temperatures, modelled in the SYNKOPE project showed that nuclear cogeneration plants represent a solution for continued use of coal and lignite even if stricter EU CO2 emission targets will be imposed on the energy sector.

Grid stabilization aspects by balancing the heat and electricity production have been evaluated. The valuation of energy shifted is quite marginal and therefore unlikely to compensate capital costs of a dedicated plant. Energy storage in existing processes (e.g. storage under the form of hot water, variation of the production volume...) and other financial arrangement (e.g. contract with the Transmission System Operator for modulation or reserves) is to be investigated on a case-by-case basis.

Key requirements of the US-NGNP have been reviewed and completed in the light of European Utility Requirements. Although no major discrepancies have been highlighted, some specific points (e.g. Limits for radionuclides, calculation methodology…) are country specific and may have to be adapted.

10 Acronyms and definitions

Acronym	Definition
DBA	Design Basis Accident
DBC	Design Basis Conditions
DEC	Design Extended Conditions
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CTL	Coal To Liquid
EC DG RTD	European Commission – Directorate General for Research and Technological Development
ENTSO-E	European Network of Transmission System Operators for Electricity
EHV	Extremely High Voltage
EPA	Environment Protection Agency
ETS	Emission Trading Scheme
EUR	European Utility Erquirements
GHG	Greenhouse Gas
HES	Hybrid Energy System
HTR	High Temperature Reactor
HV	High Voltage
HVAC	Heating, Ventilation, Air-conditionning
IAEA	International Atomic Energy Agency
IRR	Internal Rate of Return
LWR	Light Water Reactor
MCR	Main Control Room
MToe	Million Tonnes of Oil Equivalent
NHSS	Nuclear Heat Supply System
NI	Nuclear Island
NPP	Nuclear Power Plant
NPV	Net Present Value
OECD	Organisation for Economic Cooperation and Development
RES	Renewable Energy Sources
SMR	Steam Methane Reforming
SMRs	Small and Modular Reactors
SSC	Structures, Systems and Components
TSO	Transmission System Operator
WENRA	Western European Nuclear Regulators' Association
WOE	World Energy Outlook

11 Bibliography

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12 Tables and figures

12.1 List of tables

12.2 List of figures