Nuclear Technology Development and Economics
2022

Beyond Electricity: The Economics of Nuclear Cogeneration

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NEA No. 7363

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Foreword

Nuclear energy is an important source of low-carbon electricity and plays a significant role in avoiding carbon emissions. It has the potential to contribute further to the decarbonisation of the world's energy sector if it is also used to provide heat for industrial applications, which today mainly run on fossil fuels. The feasibility of non-electrical applications of nuclear energy has already been demonstrated through decades of experience with approximately 67 reactors around the world (representing about 15% of the world's reactors) providing either district heating, desalination or some other form of process heat. However, to date, cogeneration applications have used only a small fraction of nuclear energy. Existing reactors can supply thermal energy for industrial applications at less than 300°C. The advanced reactors that are being developed now would reach outlet temperatures many times higher, making them suitable for cogeneration applications over a wider temperature range. Nuclear cogeneration can also enhance the flexibility of electricity supply in combination with high levels of renewables. A group of experts from the Nuclear Energy Agency (NEA) member countries was convened to investigate the challenges and opportunities for nuclear cogeneration.

The economic competitiveness of nuclear thermal energy was one of the focuses of the ad hoc Expert Group on the Role and Economics of Nuclear Cogeneration in a Low-Carbon Energy Future. The group recognised that cogeneration applications of nuclear energy are more likely to develop if they are more economical than the technical solutions they replace, namely gas-fired production of steam and electricity. A solid understanding of the economics of nuclear cogeneration, including the associated system costs, is essential. However, there is no clear methodology to assess the economic case for developing non-electrical applications of nuclear energy, even though there are proven examples of developing such applications on an industrial scale, especially for district heating. In addition, while this report focuses principally on cogeneration, it also highlights the significant potential of nuclear power, when coupled with thermal storage, to support the integration of variable renewable energy sources. While this type of system does not have to be integrated with cogeneration applications, doing so can further improve its economics and climate mitigation potential.

The purpose of this study is to fill this methodology gap by reviewing existing research and proposing an approach that can help assess the costs and benefits of developing other products besides electricity. This study also aims to assess the potential of nuclear energy to play a role in decarbonising the energy sector beyond the sole power sector by reviewing different cogeneration applications. The expert group contributed case studies demonstrating the feasibility and economics of nuclear cogeneration in various member countries. It found that nuclear energy is well placed to play a role in meeting global decarbonisation targets by providing thermal energy for industrial applications.

Acknowledgements

This report is the result of the co-operative efforts of the Nuclear Energy Agency (NEA) ad hoc Expert Group on the Role and Economics of Nuclear Cogeneration in a Low-Carbon Energy Future as well as of the staff and consultants of the NEA Division of Nuclear Technology Development and Economics (NTE). The Expert Group was chaired by Dr Frédéric Jasserand (France). Expert Group members, whose names are listed in Annex B, participated in four workshops during this project, presented the relevant work in their countries, contributed case studies and benchmarking studies for the report, and jointly developed its conclusions and policy recommendations.

NTE staff, including Dr Henri Paillère and Dr Jae Man Noh, wrote Chapters 1, 2 and 3. NTE consultants from LGI Consulting contributed Chapters 4 and 5 on business and economic models. Case studies in Chapter 6 were contributed by the members of the Expert Group. Ms Riitta Ståhl (Finland), Dr Frédéric Jasserand (France), Dr Endre Börcsök (Hungary), Mr Klemen Debelak (Slovenia) and Mr Steffen Asser (Switzerland) all contributed case studies on district heating. Dr Ramesh Sadhankar (Canada) contributed a case study on nuclear cogeneration application for oil sands operation, authored the study on benchmarking of hydrogen economic tools and contributed to the Executive Summary. Ms Riitta Ståhl (Finland) and Dr Frédéric Jasserand (France) contributed benchmarking studies on district heating. Dr Xing Yan (Japan) contributed case studies on desalination and hydrogen production using a high-temperature reactor and wrote the benchmarking study on hydrogen production costs. Dr Jong Ho Kim (Korea) contributed a case study on water desalination using an integral pressurised water reactor and another on hydrogen production using a high-temperature reactor. Dr Cristian Rabiti (United States) authored a case study on modelling nuclear-renewable hybrid energy systems.

Prof. Jan Horst Keppler, Dr Michel Berthélemy, Mr Takuya Funahashi and Mr Lucas Mir, all from the NTE Division, contributed substantively during later stages of the report. Dr Sama Bilbao y León and Ms Diane Cameron, as successive Heads of the NTE Division, provided managerial oversight. Ms Danielle Zayani supplied essential administrative support.

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Abbreviations and acronyms

2DS	2 degrees scenario
ARMA	Auto regressive moving average model
B2DS	Beyond 2 degrees scenario
BWR	Boiling water reactor
CANDU	Canada Uranium Deuterium reactor
CCGT	Combined-cycle gas turbine
CCS	Carbon capture and storage
CEM	Clean Energy Ministerial
CHP	Combined heat and power
COP21	Conference of Parties 21
DEEP	Desalination Economic Evaluation Program
DH	District heating
EPZ	Emergency planning zone
FOAK	First-of-a-kind
G4ECONS	Generation IV Excel-based Calculations of Nuclear Systems
Gcal	Gig calories
GHG	Greenhouse gases
GIF	Generation IV International Forum
Gt	Giga tonnes
GTHTR300C	Gas turbine high temperature reactor, 300 MWe, for cogeneration
GWe	Giga Watt electric
HEEP	Hydrogen Economic Evaluation Program
HRS	Heat recovery section
HTGR	High-temperature gas-cooled reactor
HTR	High-temperature reactor
HTSE	High-temperature electrolysis
HTTR	High-temperature test reactor
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
iPWR	Integral pressurised water reactor
IRR	Internal return rate
JAEA	Japan Atomic Energy Agency
KAERI	Korea Atomic Energy Research Institute
KRW	Korean won
LCOE	Levelised cost of electricity

LCOH	Levelised cost of heat
LCONE	Levelised cost of non-electric product
LCOT	Levelised cost of thermal power
LUEC	Levelised unit electricity cost
LUPC	Levelised unit product cost
LWR	Light water reactor
MED	Multi-effect distillation
MIT	Massachusetts Institute of Technology
MMBtu	Million British thermal unit
MPa	Mega Pascal
MSF	Multi-stage flash
MTL	Main transport line
MWe	Megawatt electric
MWth	Megawatt thermal
NGNP	Next generation nuclear plant
NEA	Nuclear Energy Agency
NEK	Krško Nuclear Power Plant
NOAK	Nth-of-a-kind
NPV	Net present value
NREL	National Renewable Energy Laboratory
NRHES	Nuclear-renewable hybrid energy systems
NZE	Net Zero Emissions
OECD	Organisation for Economic Co-operation and Development
O&M	Operation and maintenance cost
PBMR	Pebble bed modular reactor
R&D	Research and development
RD&D	Research, design and development
PNNL	Pacific Northwest National Laboratory (United States)
POSCO	Pohang Iron and Steel Company
PPE	Pre-project engineering
PV	Photovoltaics
PWR	Pressurised water reactor
SAGD	Steam-assisted gravity drainage
SCWR	Supercritical water reactor
SDA	Standard Design Approval
SDS	Sustainable development scenario
SMART	System-integrated Modular Advanced Reactor
SMR	Small modular reactor
SOR	Steam-oil ratio
TWh	Tera Watt-hours
USDOE	United States Department of Energy
VHTR	Very high temperature reactor

Executive summary

Background

Nuclear energy plays a significant role in the reduction of greenhouse gas emissions (GHG). In advanced economies, nuclear power is the largest low-carbon source of electricity, providing about 40% of all low-carbon generation. It is estimated that the use of nuclear power has avoided nearly 63 Gt of CO_2 emissions from 1971 to 2018 (IEA, 2019). Most of the expansion in nuclear energy that is to date considered in scenarios aiming to decarbonise the energy sector – up to 812 GWe by 2050, according to the Net Zero Emissions (NZE) scenario of the IEA (2021) – is composed of gigawatt scale electricity generating water-cooled reactors (Gen III-III+). Beyond electricity, the decarbonisation of the world's energy sector can be enhanced by the use of heat (steam) and electricity from nuclear reactors for non-power applications: district heating, hydrogen and synthetic fuel production, or desalination, all processes that today mainly run on fossil fuels (coal, oil, gas) or biomass. The feasibility of non-electrical applications of nuclear energy has already been demonstrated through decades of experience (IAEA, 2019). Non-electrical applications of nuclear energy are most likely to develop if nuclear cogeneration is more economical than the technical solutions it replaces, namely gas-fired production of steam and electricity. A solid understanding of the economics of nuclear cogeneration, including the associated system costs, is therefore essential. However, there is no clear methodology to assess the economic case for developing non-electrical applications of nuclear energy, even though such applications have been developed at an industrial scale, especially in the area of district heating. In addition, while this report focuses principally on cogeneration, it also highlights the significant potential of nuclear power coupled with thermal storage to support the integration of variable renewables. While this type of system does not have to be integrated with cogeneration applications, doing so can further improve its economics and climate mitigation potential.

This study aims to fill this methodology gap by reviewing existing research and proposing an approach that can help assess the costs and benefits of developing other products besides electricity. More broadly, this study seeks to provide an account of the potential of nuclear energy to play a role in decarbonising the energy sector beyond the sole power sector, by reviewing different cogeneration applications.

Prospects and opportunities for nuclear cogeneration

Nuclear power is a proven low-carbon source of baseload electricity and, as such, can take on a significant role in addressing climate change through cogeneration of electricity and thermal energy for the industrial sector. Heat production is responsible for a large part of air pollution issues worldwide, on top of contributing to global warming and CO_2 emissions. Unlike electricity, heat is produced close to where it is consumed. This means that when fossil fuels are burnt for building or industrial heating or in transport, airborne pollutants are spread out over residential and industrial areas, causing sometimes severe public health problems for urban residents and workers. Nuclear power would be able to provide heat without the same air pollution.

Another advantage of nuclear power is its stable production cost. Uranium only represents 5% of the cost of producing nuclear power (IEA/NEA, 2010) which largely helps to disconnect electricity/heat production costs and fuel market prices compared to fossil fuel-based generation and provides energy security to consumers. Nuclear cogeneration also significantly improves energy efficiency and the utilisation of primary energy resources. About two-thirds of the energy that is converted to produce electricity is lost as waste heat and this waste heat occupies a large portion of the total primary energy consumption in many countries. Cogeneration can dramatically reduce primary energy resource consumption by increasing the efficiency in energy use from a global average of 37% for conventional power generation to 90% for cogeneration of electricity and heat (IAEA, 2019). Nuclear cogeneration provides flexibility by enhancing load following. A nuclear power plant can be operated at full thermal load while meeting the variable demand from the grid, thereby improving the economics of the plant through the additional revenues such an arrangement would bring. There have been proposals to set up nuclear-renewable hybrid energy systems, composed of nuclear and renewable sources, electrical and thermal energy storage, and a process plant to produce a co-product. Nuclear cogeneration can in this way play an important role in supporting the integration of high levels of renewable sources into the grid. Nuclear-renewable hybrid energy systems can dynamically apportion energy between the production of electricity and industrial product to maximise returns (Bragg-Sitton et al., 2016). A range of configurations can be considered that can either combine cogeneration and thermal storage or only include thermal storage. The relative merits of these different approaches need to be assessed on a case-by-case basis.

At the end of 2020, 70 units of the operational nuclear reactors had been used, at least partly, for non-electrical applications (IAEA, 2021). Although the total operating experience amounts to about 750 reactor-years, only a small fraction of the nuclear thermal energy has been used for cogeneration applications (IAEA, 2017a). Applications of nuclear thermal energy to date have been limited to low-temperature applications such as desalination and district heating, which require thermal energy at temperatures up to a maximum of 200°C which can be supplied by the current generation of reactors. There have been very few applications of nuclear thermal energy for industrial processes. The advanced nuclear reactors that are under development as generation IV (GIF, 2014) reactors will have higher outlet temperatures and will thus be more suited to supplying heat for industrial processes. The European Union-funded research programme end-user requirement for process heat applications with innovative reactors for sustainable energy supply (EUROPAIRS) studied segments of the European heat market and the outlook for nuclear cogeneration (Bredimas, 2014). According to this research, nuclear energy can become competitive in the short term in some market segments (existing conventional cogeneration market, pre-heating for specific industrial applications and cogeneration of industrial gases in addition to heat and electricity).

Several vendors have also started developing small modular reactors (SMRs), some of which are based on generation IV concepts. Some of the SMR concepts are being targeted for cogeneration applications such as sea water desalination, hydrogen production and industrial heating. The integral pressurised water reactor (PWR) SMRs with advanced passive safety features might be more acceptable for siting near residential or industrial applications compared with the present generation of PWRs. This type of reactor can therefore represent a promising solution for low-temperature cogeneration. As for other types of nuclear systems, designs with safety features allowing siting close to applications and with relatively small power outputs will be better suited to cogeneration applications. In particular, advances in the design of high-temperature generation IV reactors and thermal energy storage systems present opportunities for high-temperature nuclear heat applications to replace fossil fuels.

Business and economic considerations

Financing a nuclear cogeneration plant raises additional challenges and opportunities compared to electricity-only nuclear plants because there are more stakeholders involved. Cogeneration plants cater to two different markets: electricity and heat (or industrial product). In most countries, power grids are developed to a broader extent than heat networks. Therefore, the cost of reaching a new electricity consumer is negligible compared with the cost of developing infrastructure to supply heat to new clients. The most important parameter defining cogeneration market segments is temperature. When considering nuclear power as a heat source, it is therefore important to consider the thermal capabilities and limits of the various reactor technologies. Other significant parameters are: the amount of heat needed; specific safety requirements; plant adaptation to load transients; plant availability and reliability; heat transport technological limits; and, very importantly, the procedure of licensing of nuclear power plant coupled with a cogeneration facility. Technically, two integration levels are commonly distinguished:

- electrically or contiguously coupled systems, where only electrical energy is drawn from the nuclear reactor and used for non-electrical applications; and

- thermal coupled systems, where both electrical and thermal energy is drawn from the nuclear reactor and used for non-electrical applications (IAEA, 2019).

Economically, cogeneration plants can adopt either an integrated or a non-integrated business model. In a non-integrated business model the nuclear plant and heating network are owned by two separate companies. The extent of integration between various stakeholders, including the nuclear plant operator, end user of heat, energy manager and distributor, and the grid operator, will depend on technical and safety considerations as well as the market segment targeted for the cogeneration application. The financing and ownership model for an application will depend on the extent of economic integration. For district heating applications, both integrated and non-integrated business models have been used. Integrated models were used for district heating in the Soviet Union when both the nuclear plant and the heating network were built at the same time and owned by the same utility. The district heating system in Beznau, Switzerland, is a non-integrated system where the nuclear plant and heating network are owned by two separate companies. In most cases, the desalination plants are owned and operated by the same companies as the nuclear power plant as integrated clusters. Therefore, the two most common ownership models for nuclear desalination are where the owner also builds and operates the plant and where the owner is a standalone entity. In the future, the growing demand for fresh water may lead to the operation of the nuclear power plant and the desalination facilities being handled by separate companies. Since there is no experience in high-temperature nuclear cogeneration (> 250°C), no business model currently dominates. Therefore, it will be necessary to devise innovative solutions (in funding, business modelling, on-site integration, etc.). In fact, the prevailing trend towards energy management systems (integrated or not) in which chemical companies are not involved in energy management shows that these heat end users prefer to focus on their core business. The nuclear-renewable hybrid energy systems (NRHES) could include a nuclear reactor, power generation unit, windmills, solar photovoltaics (PV), thermal and electrical storage, as well as an industrial process. The NRHES capital costs far exceed those of any of the subsystems. Therefore, creative business models would be required for a NRHES to enable large investments and set up a business structure that would ensure internal energy dispatch decisions are made to maximise the profit for the entire NRHES and not for individual subsystems.

Cogeneration applications of nuclear energy are most likely to develop if nuclear cogeneration is more economical than the technical solutions it replaces, essentially gas-fired production of steam and electricity. Because of its large upfront capital costs (for large light water reactors [LWRs] or advanced generation IV reactors) and economies of scale, nuclear energy might be appropriate (i.e. competitive against fossil fuel applications) for significant combined heat and electricity demand. SMRs may certainly address other market segments if they demonstrate their competitiveness. A solid understanding of the economics of nuclear cogeneration, including the associated system costs, is therefore essential. Although there are proven examples of developing non-electrical applications of nuclear energy at industrial scale, especially in the area of district heating, there is no clear methodology to assess the economic case for developing such applications further. The lack of a well-defined economic assessment methodology makes the development of a business case for non-electrical applications of nuclear energy difficult. One of the aims of this study was to fulfil this methodology gap by developing an approach that can help assess the costs and benefits of developing other products besides electricity.

The levelised cost of electricity (LCOE) has been used as a measure of the production cost of a single-purpose nuclear reactor producing only electricity. However, there is no straightforward way of estimating levelised costs for a dual-purpose plant producing both electricity and a non-electrical product such as heat, desalinated water or hydrogen. The challenge is allocating the joint costs as both products require joint resources. Some costs are specific to the production of non-electrical products (e.g. desalination plant) or to the production of electricity (e.g. power generator, power transformer) and therefore can easily be allocated to one activity or the other. But joint costs need to be estimated together before being allocated. Since joint costs are dominant in nuclear cogeneration, the way they are allocated is important.

This study explored various cost allocation methods. Credit cost allocation methods were used in some of the economic models available in the public domain, including G4ECONS V2.0 (GIF, 2008), HEEP (IAEA, 2017b) and DEEP, which are commonly used for economic studies. Prorating cost allocations involves allocating the joint costs in proportion to the market values of the products or in proportion to exergy or calorific value. The opportunity cost method is used to derive the cost of the least important product and is based on costing the product to obtain the same revenue as full electricity production. This business-oriented costing method is useful to estimate the minimum selling price for the secondary product, making sure that the secondary application does not impede the primary production and its revenue stream.

Some economic methods suit specific cogeneration applications better than others, depending on their business models and the project characteristics. The main considerations for the choice of a cost allocation economic model depend on the business model, market conditions and the intended use of cogeneration. For example, for a desalination application using a significant portion of the reactor thermal output, the power credit methodology for cost allocations between electricity and heat is more appropriate. However, if the desalination uses only the waste heat from the reactor, the exergetic method is more applicable. For a district heating application, the opportunity cost method is certainly the most suitable when the nuclear power plant already exists and operates; it allows the district heating application to be considered as an extra source of revenue, not interfering with the existing business model. For nuclear-based hydrogen production, the IAEA has developed a specific tool (HEEP) to conduct the economic assessment that uses power credit methodology. HEEP accounts for transport and storage costs, which allows to consider both centralised and distributed business models for hydrogen production and distribution. However, different approaches may be required for systems that are being considered as a single-purpose plant producing only hydrogen. Economic models for the nuclear-renewable hybrid energy systems, which consist of a nuclear plant, renewable generating sources and industrial processes, focus on maximising profit by allocating energy (thermal and electrical) to the production of electricity and the industrial process, while taking into consideration market prices and demand.

Case studies

A set of case studies developed by the members of the expert group are included in this report to illustrate potential applications of nuclear cogeneration and to provide practical examples of the diversification of nuclear energy use tailored to meet multiple urban and industrial heat and power demands without GHG emissions during operations.

The first example of the diversification of nuclear energy use is district heating, which supplies hot water or steam to a group of urban residential or commercial buildings through a heat distribution pipe network. Case studies on district heating included both the existing systems as well as the proposed projects. In Switzerland, the Beznau Nuclear Power Plant has continuously provided up to 20 000 people with thermal power for more than three decades. The nuclear district heating can be competitive compared with the fossil fuel-based solutions, even with depressed fuel prices (IAEA, 2019). In addition to cost-competitiveness, public acceptance has been enhanced by the high availability of the district heating system since its commissioning in 1980s. There exist five backup heating plants, which can be used if unscheduled outages affect both units of the Beznau Nuclear Power Plant at the same time. The economic assessment shows that steam extraction from a nuclear power plant could be a beneficial alternative in the context of decreasing market prices for electrical energy, especially if there is flexibility to react in time to market prices. The Paks Nuclear Power Plant in Hungary provides a small fraction of thermal energy to about 2 600 households. Other case studies explored connecting the existing or new heating networks to existing nuclear plants in Finland, France and Slovenia. In most cases, the steam for district heating is taken from the outlet of a high-pressure turbine. The decrease in electrical output is small compared to the thermal energy supplied to the district heating network, thus improving the overall energy efficiency of the nuclear power plant up to 85%. The heat exchangers in the intermediate circuit form the physical barriers against the spread of radioactivity from the reactor circuit to the district heat transport system. The balance of plant is designed to handle seasonal fluctuations in heat demand. Although these studies show potential for nuclear district heating to replace conventional sources, certain challenges were noted. The remaining operating time frame of the existing nuclear power plant, including a planned extension, is a consideration for the long-term viability of a new district heating system connection. The economic competitiveness of nuclear district heating also depends on the distance between the plant and the heat consumers, the extent of retrofitting required for the heating network, and the cost of retrofitting an existing nuclear plant or building a new one. The high investments in plant and distribution network retrofit and long-term operations of this technology would require favourable financing and policy support to promote this low-carbon heat source on the sites where it is technically feasible.

Another example of nuclear heat application is desalination, which is a process to obtain high purity drinking water, domestic water and industrial water by removing dissolved substances including salt from seawater or brackish water. Currently, energy required for desalination is provided in the form of electricity for reverse osmosis desalination or heat mostly generated by natural gas for thermal desalination. Nuclear can also provide the energy demand for desalination. There have been 250 reactor-years of cumulative experience of nuclear desalination with 17 reactors around the world (IAEA, 2017a). Although most of the past and current water desalination plants were based on heat supplied from water-cooled reactors, the cases explored in this study are based on advanced reactor concepts. The GTHTR300C is a multi-stage flash (MSF) desalination process specially configured and optimised to efficiently recover the sensible waste heat from the power conversion cycle of Japanese high-temperature gas-cooled reactors. It is shown to produce 45% more water than the traditional MSF. For the Middle East market conditions, the cost of desalinated water produced by the GTHTR300 is estimated to be significantly lower compared with that of the conventional MSF cogenerating with an oil and gas-fired combined-cycle gas turbine (CCGT) power plant (IAEA, 2019). Another case study showed economical desalination of sea water using hybrid of reverse osmosis and multi-effect distillation (MED) units coupled with SMART, a Korean-designed 330 MWth integral pressurised water reactor. Desalination processes also often require both heat and electricity. A small and medium-sized reactor is better suited for desalination, which is often operated in a cogeneration mode to supply fresh water together with electricity to a city where fresh water is scarce (IEA, 2016). Nuclear-based water desalination plants in water-scarce regions have provided a vital water source to the population for economic growth. Therefore, water desalination projects may improve public acceptance of nuclear cogeneration (IAEA, 2019).

Other case studies look at the use of nuclear process heat for various industrial applications in member countries. These case studies encompass heat supply for large industrial complexes, including heat supply for hydrogen production, using high-temperature thermochemical and electrolysis processes, and steam and hydrogen supply for bitumen extraction and upgrading.

Case studies of hydrogen production were based on high-temperature, water-splitting processes using high-temperature heat and electricity from advanced generation IV type reactors. Large-scale hydrogen production using a sulphur-iodine thermochemical process coupled with a very high-temperature reactor (VHTR) with outlet temperature up to 950°C was found to be economically feasible in Korea and Japan. The analysis also showed that the sulphur-iodine thermochemical process is economically competitive compared with water electrolysis, which is the only method currently available for GHG-free hydrogen production. A case study for large-scale hydrogen production using high-temperature steam electrolysis (HTSE) coupled with a supercritical water-cooled reactor (SCWR), with an outlet temperature of 625°C, showed that the levelised cost is significantly higher than the cost of hydrogen produced with the conventional process using natural gas with prevailing low prices in North America. This analysis shows that hydrogen produced with nuclear energy can be competitive in certain regions, depending on natural gas prices and carbon taxes. The high-temperature water-splitting processes are still under development and have not been demonstrated on an industrial scale but are expected to be ready when the VHTR technology is ready for deployment. Development of the interface with industrial heat users, including intermediate heat exchangers, ducts, valves and associated heat transfer fluid, is one of the key objectives for VHTR development. A case study also explored the use of nuclear energy for bitumen and synthetic crude production from oil sands. In 2018, the oil sands industry contributed about 12% of Canada's total greenhouse gas emissions (Natural Resources Canada, 2020). Currently, natural gas is used as a fuel for bitumen recovery and for hydrogen production for upgrading bitumen to synthetic crude. High-pressure steam is used for in situ extraction of bitumen from underground oil sands deposits by a process called steam-assisted gravity drainage. Various feasibility studies found that the use of nuclear reactors to produce high-pressure steam or hydrogen is not competitive with the current methods because of the prevailing low prices of natural gas.

The growth in variable renewable energy sources such as wind and solar, incentivised by subsidies and priority dispatch policies in some jurisdictions, is having an adverse effect on baseload generators. The wholesale market prices for electricity have decreased due to large amounts of generation from subsidised renewables or cheap natural gas. This makes NRHES an interesting concept. The NRHES includes cogeneration applications using thermal energy from the nuclear reactor as a co-product of electricity. The cogeneration of electricity and an industrial product provides opportunity for economically viable hybrid systems in a volatile electricity market, with fluctuating demand and intermittent renewable generation. Hybrid systems are capable of offering load-following services to make up for the intermittency of electricity generation from renewables. One of the case studies demonstrates modelling for the optimisation of the NRHES based on various parameters including the market prices for electricity and co-product, fluctuating demand for electricity, and the intermittency of renewable generation.

In addition to the case studies by the members of the expert group, two generic benchmark cases for the nuclear cogeneration applications were explored: one on district heating and the other on hydrogen production. The purpose of these benchmark studies is to illustrate the methodologies reviewed in this study against potential applications.

Recommendations

Although nuclear energy has contributed significantly to avoiding greenhouse gas emissions by providing low-carbon electricity, the potential of nuclear thermal energy to replace fossil fuels for industrial applications has not been fully realised. The ongoing development of higher-temperature advanced reactors, SMRs and large-scale thermal storage is expected to present further opportunities for cogeneration applications in the future. To realise the potential of nuclear cogeneration for decarbonisation, the group of experts made a set of recommendations.

- Governments should consider developing national/regional roadmaps for decarbonising the heat sector: in most countries, only roadmaps for the electricity sector are developed. These roadmaps should recognise nuclear energy's potential for replacing fossil fuel used for heating in industrial and commercial sectors.
- Governments should recognise that nuclear cogeneration can be an integral part of low-carbon energy systems. Government policies should be conducive to promoting nuclear thermal energy and discourage fossil fuel use through carbon taxes and other incentives. Such policies should also recognise that nuclear cogeneration helps increase penetration of renewables on the grid while ensuring grid reliability and the economic viability of the integrated system.
- Governments should co-ordinate energy and water policies to advance nuclear desalination projects. The energy and water planning communities should work together on innovative financing and business models for water desalination projects.
- There is a need for demonstration projects to advance nuclear cogeneration, and these should be funded by public/private partnerships with a strong participation by industrial actors.
- Awareness and information regarding the potential of nuclear cogeneration should be further developed and studies on the integration of nuclear and renewables using nuclear cogeneration as an energy storage/buffer should be carried out, including full life cycle assessments.

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Chapter 1. **Introduction**

In the *World Energy Outlook 2019*, the International Energy Agency (IEA, 2019a) projects that if the world continues along its present path, without any additional changes in policy (the so-called Current Policies Scenario), energy demand will grow by 1.3% per year to 2040 and result in a relentless upward trend in energy-related carbon emissions. In contrast, under the Stated Policies Scenario (SPS, previously known as the New Policies Scenario) which takes into account the announced changes in policies, energy demand grows by 1% per year to 2040.

The energy landscape has been directly impacted by the COVID-19 pandemic that hit the world in 2020. According to the *World Energy Outlook 2020* of the International Energy Agency (IEA, 2020), energy demand in 2020 was 4.6% lower than in 2019. For the future, the agency projects that total energy demand will return to 2019 levels by 2023, assuming the risks to public health are brought under control during the year 2021 and taking into account the announced changes in the policies, (the so-called Stated Policies Scenarios, STEPS). Under the Delayed Recovery Scenario (DRS), which adopts a more pessimistic view on the health and economic outlook, the global energy demand only returns to its pre-crisis level in 2025. Under the Sustainable Development Scenario (SDS), which builds coherent policies from shared long-term climate objectives, primary energy demand drops 7% by 2030 from 2019 levels. Finally, for the Net Zero Emissions case by 2050 (NZE), which strengthens the SDS analysis and scales up the net zero objective from advanced economies to the entire world, primary energy demand falls by 17% between 2019 and 2030, reaching 2006 levels by that date.

The SDS involves major transformations in the energy sector, led by electricity, to slow emissions but falls short of the sustainability goals. The SDS, which is aligned with the Paris Agreement (UNFCC, 2015) and goals of providing energy access to all while ensuring cleaner air, involves sharp cuts in emissions across all sectors to limit the global temperature rise to below 2°C.

The SDS requires an ambitious transformation of the energy sector. Growth in demand for electricity is projected to outpace growth in demand for energy more broadly. Under the SDS, electricity plays an important role, with consumption growing past 2040 and overtaking that of oil, mainly due to electric vehicles, alongside growth in renewables and other clean electricity sources. This scenario (IEA, 2017) estimates that the power sector could be virtually decarbonised by the middle of the century thanks to the replacement of fossil-fuel generation by large shares of renewables and other low-carbon technologies such as nuclear power or carbon capture and storage (CCS). There remains, however, the issue of decarbonising other sectors, including the transport and heat sectors. While nuclear energy is recognised as a low-carbon source of electricity, and is cited in a number of countries' nationally determined contributions as part of their commitments to reduce CO_2 emissions in the context of the Paris Agreement, its potential for supplying low-carbon heat to non-electrical applications is often forgotten.

The purpose of this study is to provide an updated account of the potential of nuclear energy to play a role in decarbonising the energy sector beyond the sole power sector, through a study of different cogeneration applications, some based on established industrial applications, others based on feasibility studies with existing technologies, or technologies currently under development. Some consideration is also given to the design of future low-carbon energy systems where nuclear energy and renewables could co-exist in a cost-efficient manner, and where nuclear cogeneration would play an important part in the operation of the system.

There were 443 nuclear reactors worldwide as of 2021. Most only produce electricity and generate about 10% of the world's supply (2 586 TWh out of about 26 000 TWh in 2019) (IAEA, 2020). Nuclear energy has played a significant role in efforts to reduce greenhouse gas emissions (GHG) while producing electricity. In advanced economies, nuclear power is the largest low-carbon source of electricity, accounting for about 40% of all low-carbon generation. It is estimated that the use of nuclear power has avoided nearly 63 Gt of CO_2 emissions from 1971 to 2018 (IEA, 2019b). Replacing it with fossil fuel-fired generation would represent additional yearly emissions of 2.5 Gt of CO_2 if replaced by coal, or 1.3 Gt of CO_2 if replaced by gas. If the present nuclear energy capacity were to be phased out and replaced by the other technologies in the world's current energy mix, including fossil fuels and low-carbon sources such as hydro and other renewables, global annual CO_2 emissions from electricity supply would rise by 12%. Most of the nuclear expansion that is foreseen up to 2050 in scenarios that aim at decarbonising the energy sector – up to 812 GWe by 2050, according to the NZE scenarios of the IEA (2021) – would likely be composed of large electricity generating water-cooled reactors (Gen III-III+), with typical units in the range 1 000 MWe to 1 750 MWe. Small modular reactors (SMR) and the first generation IV reactors would also be deployed in this time frame.

The decarbonisation of the world's energy sector can be further supported by the use of heat (steam) and electricity from nuclear reactors for non-power applications: district heating, production of hydrogen and synthetic fuels, and desalination, which are all processes that today mainly run on fossil fuels (coal, oil, gas) or biomass. As demand grows for fresh water and for transportation fuel that can be extracted and generated from large resources of heavy oils and bitumen using steam and hydrogen, the GHG emissions from fossil fuel-based cogeneration are set to increase unless low-carbon technologies such as nuclear energy are used. The feasibility of non-electrical applications of nuclear energy has already been demonstrated through decades of experience with about 67 reactors around the world (about 15% of all reactors) providing either district heating, desalination, hydrogen or some other form of process heat (IAEA, 2019b). In its 2017 edition of Energy Technology Perspectives (IEA, 2017), the IEA recognises that nuclear cogeneration may indeed play an important role in decreasing emissions from the non-power sectors, especially with a view to achieving the ambitious goals set in the Paris Agreement of limiting global warming to well below 2°C (beyond 2°C scenario, or B2DS).

At the end of 2015, 67 units of the operational nuclear reactors had been used, at least partly, for non-electrical applications (IAEA, 2019b), with 43 reactors used for district heating, 17 for desalination of water and 7 for industrial process heat. Although the total operating experience amounts to about 750 reactor-years, this is only a small fraction of the nuclear thermal energy.

Depending on the application, different types of reactor technologies may be required, from light water reactors (LWRs) typically operating at temperatures around 300ºC, to liquid metal cooled reactors (LMRs) operating at around 500ºC, and gas-cooled high-temperature reactors (HTR) operating at temperatures in the range of 700-1 000ºC. SMRs are increasingly the focus of much attention. There are SMRs of different technology types (LWR, LMR, SMR or HTR), with the most mature designs being of LWR type. In addition to modularity features, many of the SMRs are being designed with the option of providing both electricity and heat.

Non-electrical applications of nuclear energy are most likely to develop if nuclear cogeneration is more economical than the technical solutions it replaces, namely gas-fired production of steam and electricity. A good understanding of the economics of nuclear cogeneration, including the associated system costs, is thus essential. However, there is no clear methodology to assess the economic case for developing non-electrical applications of nuclear energy, even though there are proven examples of developing such applications at industrial scale, especially in the area of district heating. Looking at past or current examples, it is also sometimes difficult to assess the clear benefits to the operator of the nuclear power plant, to the end-user of the non-electric product (usually heat) delivered by the nuclear power plant, and to the community at large. Reasons include the fact that, in some cases, non-electrical applications were developed on the basis of centrally planned infrastructure with little concern for the profitability of the projects, and also the fact that although there is usually a clear market price for electricity delivered to customers, the pricing of heat does not always adequately reflect the production and distribution costs. The lack of a well-defined economic assessment methodology makes the development of a business case for non-electrical applications of nuclear energy difficult.

This report aims to fill this methodology gap by reviewing existing studies and proposing an approach that can help assess the costs and benefits of developing other products besides electricity. An example of existing studies is a publication by Carlsson et al. (Carlsson, 2012) that looked at the competitiveness of SMRs in the future European cogeneration market using the so-called target cost methodology. This report was expected to outline generic economic assessment methodologies and business models for nuclear cogeneration, which would be applicable to specific cogeneration processes, and the respective nuclear reactor technologies such as water-cooled reactors, high-temperature reactors, liquid metal cooled reactors, small modular reactors, etc. The application of economic methodologies and business models for various applications such as district heating, desalination, hydrogen production or some other form of process heat is also discussed in this report.

A set of case studies developed by the member countries are provided to illustrate various potential applications of nuclear cogeneration. These cases aim to provide practical examples of how nuclear energy use can be diversified to meet various urban and industrial heat and power demands while keeping GHG emissions low.

The first example of the diversification of nuclear energy use is district heating, which supplies hot water or steam to a group of urban residential or commercial buildings through a heat distribution pipe network. The report includes case studies in which nuclear energy provides heat for an entire town or part of a town after existing reactors were retrofitted or new reactors built.

Another example of nuclear heat application is desalination, which is a process to obtain high purity drinking water, domestic water, and industrial water by removing dissolved substances, including salt, from seawater or brackish water. Desalination plants around the world could produce up to 35 billion cubic metres of fresh water annually (Jones et al., 2019). The Middle East and North Africa (MENA) region account for approximately half of the total production capacity. The MENA region currently accounts for almost 90% of the energy consumed for desalination throughout the world because the desalination of seawater is more common in this region. This process requires an order of magnitude more energy than the desalination of brackish water. Currently, energy required for desalination is provided in the form of electricity for reverse osmosis desalination or heat, mostly generated by natural gas, for thermal desalination. Nuclear energy can also provide the energy for desalination. A small and medium-sized reactor is better suited for desalination, which is often operated in a cogeneration mode to supply fresh water together with electricity to a city where fresh water is scarce (IEA, 2016). Desalination processes also often require both heat and electricity.

Other case studies include examples where nuclear process heat is provided for various industrial applications in member countries. Nuclear energy is almost the only reliable source of process heat that does not emit any greenhouse gases. This category of case studies encompasses heat supply for large industrial complexes, including heat and hydrogen supply for bitumen extraction and upgrading, heat supply for paper mill, and heat supply for thermochemical and high-temperature electrolysis hydrogen production. The required temperatures for the applications range from 200 to 1 000°C. Light water reactors can provide heat at low temperatures up to 250-300°C, very high temperature gas-cooled reactors can provide heat at high temperatures up to 900°C, and other reactor types including sodium fast reactors (SFRs) can provide heat in the intermediate temperature range.

One of the interesting concepts is the so-called hybrid energy system, which has a large share of renewable technologies. The hybrid system includes an industrial process and thermal energy storage, for example for producing hydrogen or synthetic fuel, using thermal energy from the nuclear reactor as a co-product of electricity. The cogeneration of electricity and an industrial product provides the opportunity for economically viable hybrid systems in a volatile electricity market, with fluctuating demand and intermittent renewable generation. Hybrid systems are capable of offering load-following services to make up for the intermittency of the electricity generation from renewables. Modelling of hybrid system optimisation is presented as one of the case studies.

In addition to the case studies from member countries, two generic benchmark cases for the nuclear cogeneration applications were explored: one on district heating and the other on hydrogen production. The purpose of these benchmark studies is to illustrate the methodologies reviewed in this study against proven applications, namely nuclear district heating, for which operational data and experience exists. Member countries assessed the projected costs of heat or hydrogen generated by fossil fuels versus renewables versus nuclear energy for these benchmarks in their own economic circumstances and using their own analytical tools.

Finally, the report provides the conclusions and recommendations of the expert group.

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Chapter 2. **Prospects for nuclear energy development and nuclear cogeneration**

2.1. **Prospects for nuclear energy development**

At the end of 2020, 443 nuclear power plants were in operation around the world, representing 393 GW_e in capacity (IAEA, 2020). In addition, there are 53 nuclear power plants with a total capacity of 54.5 GWe under construction worldwide. Global nuclear electricity production could continue to increase in the coming years provided that decisions by regulators, operators, and governments make it possible to operate reactors until the end of their design lifetime, and that the Japanese reactors are progressively restarted.

Nuclear power accounts for approximately 10% of electricity production globally (IEA, 2021a), and 17.5% in OECD countries (NEA, 2022).

The low and high case estimates of nuclear generating capacity by the IAEA (2019a) reflect contrasting underlying assumptions on the factors affecting nuclear power deployment in different regions. The world nuclear electrical generating capacity is projected to increase by 80% to 715 GWe by 2050 in the high case. In the low case estimates, total nuclear capacity is expected fall slightly from the current level of 396 GWe to 371 GWe by 2050. The IAEA (2019a) also notes that interest in nuclear power remains strong in many regions and the commitments under the Paris Agreement have the potential to support nuclear energy development. The growth in nuclear energy would mainly be driven by non-OECD countries, with the People's Republic of China, India and Russia being the main contributors.

In its reference scenarios, the IEA (IEA, 2021a) underlines that commitments made at the COP21 Conference in Paris in 2015 will be difficult to reach without significant growth in nuclear power production. The IEA considered four scenarios:

- Stated Policies Scenario (STEPS), "which reflects current policy settings based on a sector-by-sector assessment of the specific policies that are in place, as well as those that have been announced by governments around the world."
- Announced Pledges Scenario (APS), "which assumes that all climate commitments made by governments around the world, including nationally determined contributions and longer-term net zero targets, will be met in full and on time."
- Net Zero Emissions by 2050 Scenario (NZE), "which sets out a narrow but achievable pathway for the global energy sector to achieve net zero CO_2 emissions by 2050. It doesn't rely on emissions reductions from outside the energy sector to achieve its goals."
- The Sustainable Development Scenario (SDS), like the NZE, "achieves key energy-related United Nations Sustainable Development Goals related to universal energy access and major improvements in air quality, but reaches global net zero emissions only by 2070".

The role of nuclear power is projected to be prominent under both the APS and NZE scenarios. According to IEA, a total of more than 800 GWe nuclear capacity would be required under the NZE scenario. Clear and consistent policy support would be needed for existing and new capacity, including clean energy incentives for development of nuclear alongside other forms of clean energy.

In a 2018 report, the IEA estimates an increase in nuclear installed capacity by 2040 under two different scenarios (IEA, 2018a). Under the New Policies Scenario (NPS) which considers current and planned policies, including nationally determined commitments under the Paris Agreement on climate change, the output of nuclear grows by 1.5% per year between 2018 and

2040. Under the SDS, which addresses three goals for air pollution concerns, universal energy access and limits average temperature rise to 2°C, the nuclear output grows faster, by 2.8% per year to 2040.

For nuclear energy, one of the challenges relates to the construction rate: reaching 792 715 GWe by 2050 (IAEA, 2021) or about 815 GWe by 2050 (IEA, 2021b) could mean building – and financing – between 315 and 600 new units of 1 GWe in addition to replacing approximately 200 units.

2.1.1. *Challenges for the future of nuclear power*

Nuclear power has faced several challenges in recent years, and it will continue to face them in the near future. The nuclear industry is capital intensive, with projects requiring large amounts of financing. The global financial crisis has had a significant adverse effect on nuclear power growth since 2008. Over this period, the growth of nuclear power, especially in developed countries, was also limited by the decreasing price of fossil fuel amid rapid growth in non-conventional sources such as shale gas in the United States. The nuclear sector has also been affected by recent developments in electricity markets. First, the absence of efficient CO_2 markets is a competitive disadvantage for nuclear power. Second, the growth in variable renewable energy sources such as wind and solar, incentivised by subsidies and priority dispatch policies in some jurisdictions, is having an adverse effect on baseload generators. The wholesale market prices for electricity have decreased, due to large amounts of generation from subsidised renewables or cheap shale gas.

The introduction of a significant amount of variable resources on the grid also requires the other dispatchable sources to be flexible in terms of load following and providing ancillary services. The Clean Energy Ministerial (CEM) launched the advanced power plant flexibility campaign in 2017 to commit governments to make power generation more flexible to allow the integration of variable renewable energies into the power systems. As part of this campaign, the IEA published a report (IEA, 2018b) that highlights the role of power plants in system flexibility and the policies required to advance power system flexibility. The IEA study looked at the limitations of the current generation of nuclear power plants and the options to enhance flexibility, but did not consider the advanced reactor concepts that are under development. In 2019, the CEM also launched a "flexible nuclear" campaign with the objective of modelling studies to inform decision makers and to promote communication on flexible nuclear options (CEM, 2020).

Ultimately, the main challenge for both nuclear power and renewables in the coming years will be to deal with political uncertainties. In particular, the way the Paris Agreement is implemented is a key driver for the growth of carbon-free energy production.

2.1.2. *Strengths and opportunities for the future of nuclear power*

To cope with these challenges, nuclear power can rely on its demonstrated strengths while taking advantage of opportunities. Nuclear power is a proven low-carbon source of baseload electricity and as such, it can take on a significant role in addressing climate change. Nuclear power has been the single largest source of low-carbon electricity over the past 50 years. To meet the 2-degree objective as described in the IEA's 2DS scenario, the share of nuclear in terms of global electricity production and reduction of CO_2 emissions must increase. The variability of the renewable sources can be challenging for the stability of the grid. Nuclear power has some limited flexibility, with some countries (France, Germany) operating nuclear power plants in load-following manner. We will see in this study that nuclear cogeneration can provide additional flexibility to integrated energy systems incorporating nuclear and renewable technologies.

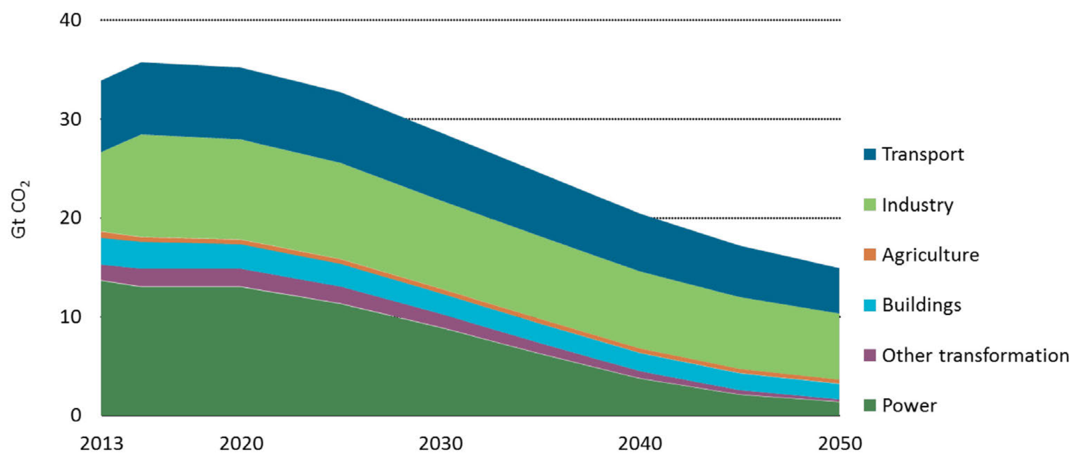
Another important strength of nuclear power is its stable production cost. First, uranium only represents 5% of the current cost of producing nuclear power (MIT, 2011; IEA/NEA, 2010) which largely helps to disconnect electricity production costs and fuel market prices compared to fossil fuel-based generation. Furthermore, nuclear power can contribute to improving the security of energy supply since nuclear fuel can be easily transported and stored, and significant uranium resources and diversified production centres exist around the world.

2.2. Prospects for nuclear cogeneration

2.2.1. *Heat markets, CO_2 emissions and air pollution*

In 2013, power production was the biggest CO_2-emitting sector, followed by transport, industry and buildings, as shown in Figure 2.1. However, in the 2DS scenario depicted in the figure, industry is expected to become the largest emitting sector by 2050, followed by transport and buildings. Since power production is accounted separately, the CO_2 emissions related to industry and buildings essentially come from heat consumption. Following a path to "well below 2 degrees" will then require developing low-carbon heat production technologies.

Figure 2.1: **Energy and process-related CO_2 emissions by sector in the 2DS**



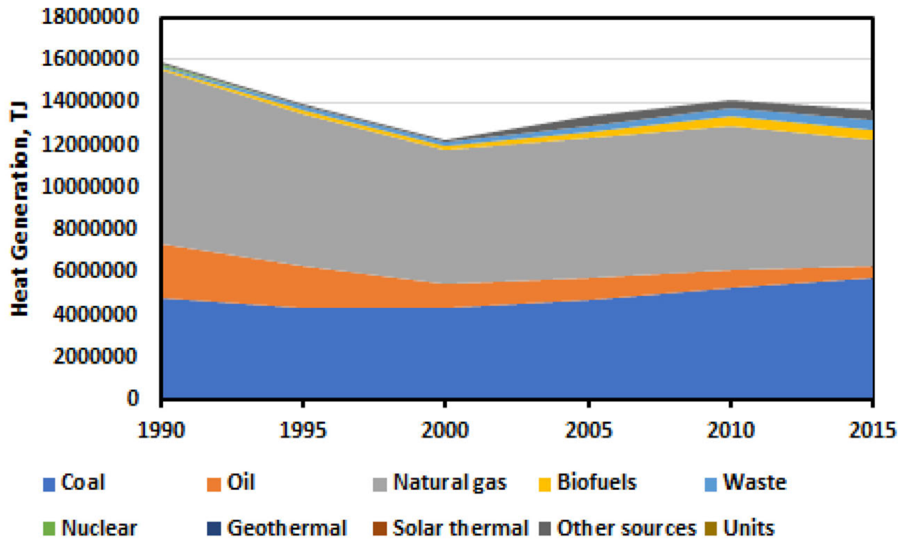
Source: IEA (2016).

When addressing the challenge of increasing global electricity production without increasing CO_2 emissions, nuclear energy can claim the benefit of being a low-carbon source of power. The same challenges arise in the heat markets. The heat sector is already a significant CO_2 emitter and is expected to grow along with socio-economic growth (increase of global population, increase of global gross domestic product [GDP]). Global energy use for heat sold as a commodity by sources is shown in Figure 2.2 based on IEA data (IEA, 2019b). Total demand for energy by industry and building sector far exceeds the heat sold as a commodity.

In addition to the concerns about global warming and CO_2 emissions, heat production is responsible for a large part of air pollution issues worldwide. Indeed, unlike electricity, heat is produced close to where it is consumed. This means that when fossil fuels are burnt for building or industrial heating or in transport, airborne pollutants are spread out over residential and industrial areas, causing sometimes severe public health problems for urban dwellers and workers.

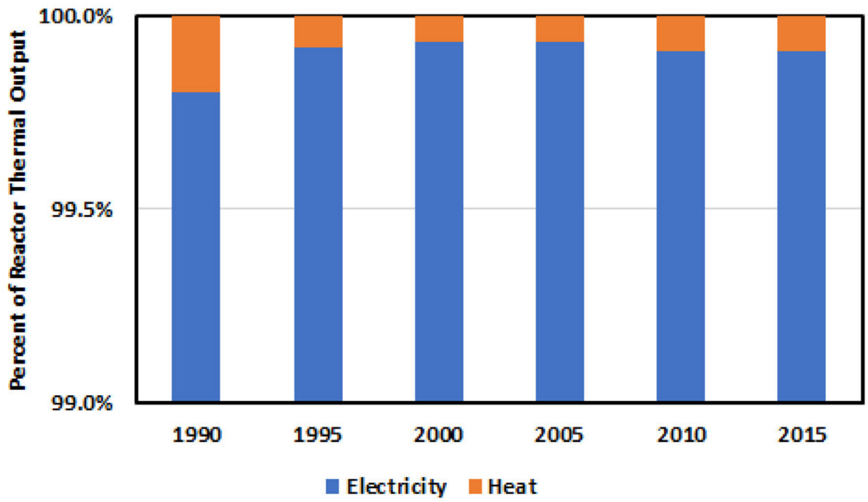
Almost 90% of industrial heat is generated from fossil fuels, showing how much room for improvement there is in terms of CO_2 emissions. In the buildings sectors, gas is the primary fuel, with fossil fuels accounting for less than 60% of the energy source. The rest of the heat used in buildings is provided by so-called "renewable energy sources", most of them being biomass combustion plants. This source of heat is considered carbon-neutral, but apart from most advanced technologies, it still emits air pollutants. There is therefore also considerable room for improvement in the buildings sector in terms of CO_2 emissions and air pollution. IEA data (2019b), depicted in Figure 2.2, show the heat generated by power plants using different fuels, operating in a combined heat and power (CHP) mode, from 1990 to 2015. As can be seen, nuclear power plants did not produce much heat as a commodity. Figure 2.3, also based on IEA data (IEA, 2019b), shows that less than 1% of the total thermal output of the nuclear power plants was used as heat, the rest converted to electricity.

Figure 2.2: **Heat production by power plants**



Source: Based on data from IEA (2019b).

Figure 2.3: **Percentage of nuclear thermal power used for electricity and heat**



Source: Based on data from IEA (2019b).

Today, nuclear has a negligible share in the final energy use for heat (< 1%). Since nuclear energy emits exceptionally low amounts of CO_2 and air pollutants, it can be considered one of the solutions to limit CO_2 emissions and air pollution in the heat sector. The heat demand depicted in Figure 2.2, which is currently largely met by the power plants operating in combined heat and power mode, could be easily accessible to the new nuclear plants, provided it is economically competitive.

2.2.2. *Overview of past and ongoing nuclear cogeneration projects*

Operating nuclear reactors in cogeneration mode to produce both electricity and heat is a technically proven solution to limit CO_2 emissions and air pollution from the heat sector, even though technical challenges remain for some specific applications. At the end of 2015, 67 units of the operational nuclear reactors had been used, at least partly, for non-electrical applications (IAEA, 2019b), with 43 reactors used for district heating, 17 for desalination of water and 7 for industrial process heat. Although the total operating experience amounts to about 750 reactor-years, only a small fraction of the nuclear thermal energy has been used for cogeneration applications. District heat applications ranged in size from 5 MWth to 240 MWth, corresponding to withdrawal of less than 5% of the total energy out of the reactors. Some of these district heating and desalination plants are still in operation. Among the district heating plants were two dedicated plants in China (IAEA, 2012) and Russia (Obninsk). The Beznau Nuclear Power Plant in Switzerland is an example of a pressurised water reactor that is run in a cogeneration mode for district heating. The Beznau plant began to supply nuclear district heating in the early 1980s and continues to do so today, serving a population of nearly 20 000. The peak district heat load is about 80 MWth (IAEA, 2017a). Experience in Switzerland shows that nuclear-based district heating is economical, safe, reliable and acceptable to the public. In Aktau, Kazakhstan, ten units of multi-effect distillation (MED) plants were coupled to a 1 000 MWth liquid metal cooled, fast breeder reactor (BN-350) to produce 14 500 m^3/d (IAEA, 2012). It produced very high quality water for industrial and potable needs using multi-stage flash (MSF) desalination units and ran for 26 years before shutting down in 1999. Sodium-cooled fast reactors are also being developed as generation IV advanced reactors. Nuclear thermal energy-powered desalination plants in India and Pakistan provide water for the nuclear plant operation.

Unlike desalination and district heating, there has been limited use of nuclear heat for industrial applications. The largest such application was the use of medium pressure steam from the Bruce Nuclear Power Plant in Canada for heavy water production. The Bruce A nuclear plant had the largest bulk steam system with a capacity of 5 350 MWth (IAEA, 2017a) and supplied ~750 MWth for heavy water production, 15 MWth for on-site building heating and about 72 MWth to an industrial park with food processing, ethanol and plastic film manufacturing plants. The heavy water plants were the largest ever built and produced over 16 000 metric tons of heavy water between 1973 and 1997. The heavy water production plant was located near the nuclear power plant and was licensed by the national regulator. In Germany, the Stade nuclear plant supplied 60 t/h of process steam at 0.8 MPa and 270°C to a salt refinery between 1983 and 2003. In Switzerland, the Gösgen Nuclear Power Plant supplies about 45 MWth thermal energy to a cardboard factory and a paper mill, using medium pressure steam (1.2-1.5 MPa) (IAEA, 2017b).

2.2.3. *Outlook for nuclear cogeneration*

Despite the significant experience in nuclear cogeneration described above, nuclear power's contribution to global heat is still negligible, as shown in Figures 2.2 and 2.3. To quantify the potential contribution of nuclear to tackle climate and health issues related to heat production (CO_2 emissions, air pollution), it is necessary to estimate the potential penetration rate of nuclear cogeneration plants in this market.

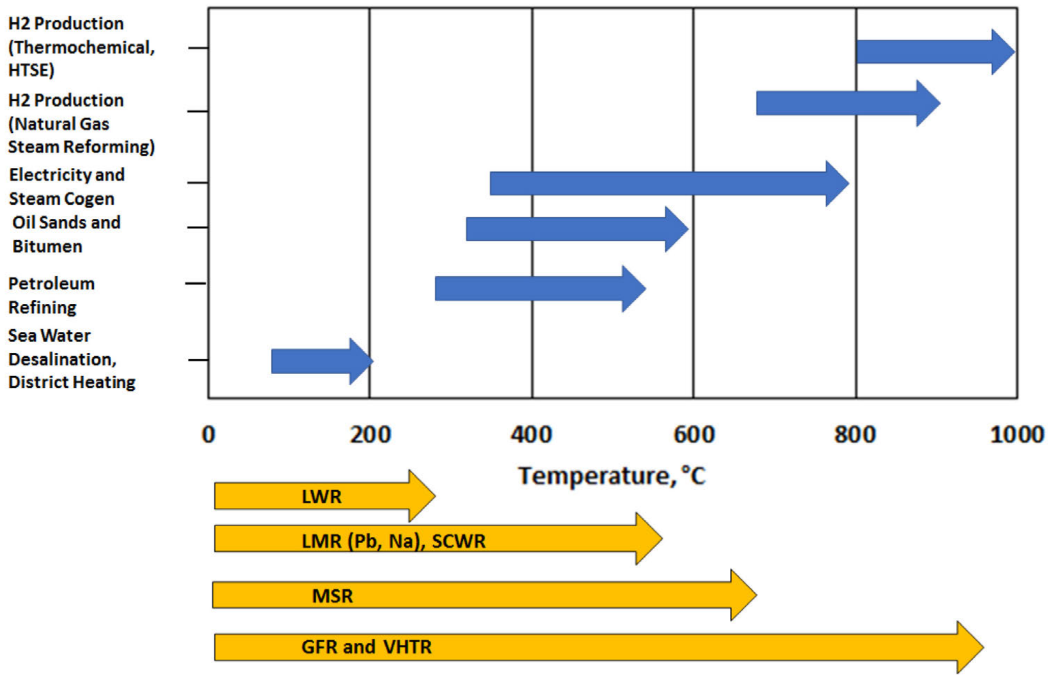
In the short and medium terms, it would be unrealistic (given the required build rates to fulfil its role in the power sector only) to consider nuclear taking over the entire market share of fossil fuels in heat production (approximately 70%). However, there is no major obstacle to reaching the same penetration rate as in electricity markets (approximately 10%). As shown in Figure 2.2, there is already a significant market for heat as a commodity that is being met by fossil-fuelled power plants and could be captured by economically competitive nuclear new builds.

Applications of nuclear thermal energy to date have been limited to low-temperature applications such as desalination and district heating, which require thermal energy at temperatures up to a maximum of 200ºC, which can be supplied by the current generation of reactors. There have been very few applications of nuclear thermal energy for industrial processes. The advanced nuclear reactors that are under development as generation IV reactors (GIF, 2014) will have higher outlet temperatures and will be more suited to supplying heat to industrial processes.

The IAEA launched a programme for nuclear cogeneration in the 1990s, initially focused on use of thermal energy from existing reactors for sea water desalination and district heating (IAEA, 2009). The programme was subsequently expanded to include hydrogen production and process heat applications based on high-temperature reactors that are under development. The IAEA analysed energy demand based on current practices and provided an overview of the use of nuclear energy for industrial systems and processes that have a strong demand for power generation and process heat and steam (IAEA, 2017a) including process steam for oil recovery and refineries, hydrogen generation, and steel and aluminium production. The IAEA also analysed (IAEA, 2012) various opportunities for cogeneration at existing reactors as well as advanced reactors, examining feasibility, safety considerations and economics.

Figure 2.4 summarises the outlet temperatures of the generation IV reactors being developed by GIF and potential industrial applications.

Figure 2.4: **Potential cogeneration opportunities for generation IV reactors**



More specifically, a EU-funded research programme (EUROPAIRS) studied segments of the European heat market and the corresponding outlook for nuclear cogeneration (Bredimas, 2011, 2014). According to this research, nuclear energy can become competitive in the short term in some market segments (existing conventional cogeneration market, pre-heating for specific industrial applications and cogeneration of industrial gases in addition to heat and electricity). In Europe, these segments would account for approximately 1 200 TWh_{th}/year. Meanwhile, the market segment composed of boilers and burners operated within industrial facilities or embedded into industrial processes would amount to 1 800 TWh_{th}/year, although nuclear is unlikely to penetrate this segment in the short or medium term. Finally, this study did not address the European heat consumption in individual housing disconnected from any heating network. Nuclear reactors could be better suited for new district heating networks built for densely populated areas, though it is anticipated that fuel switching to electricity (decarbonised) may be a more affordable option (direct space heating or heat pumps).

Besides, several nuclear cogeneration initiatives and projects are being considered, such as in the examples listed below.

- China is constructing a commercial high-temperature reactor – power module (HTR-PM) plant consisting of two 250 MWth reactors with outlet temperature of 750°C. It will be initially used to demonstrate power generation using steam turbine but there are longer-term objectives of using it for industrial heat applications, including process steam and hydrogen production (IAEA, 2019a).
- The Generation IV International Forum (GIF) recognised the potential of generation IV advanced reactors for alternative energy products (GIF, 2014) and set up a specific project to develop greenhouse gas emissions (GHG)-free, water-splitting hydrogen production processes using nuclear thermal energy.
- Several countries in Europe are conducting nuclear cogeneration projects, such as an HTR-PL in Poland, with the goal of reducing GHG emissions from fossil fuel-powered industrial sectors
- The Japan Atomic Energy Agency (JAEA) has developed the Gas Turbine High Temperature Reactor, or GTHTR300C, for electricity and hydrogen cogeneration based on sulphur-iodine process (Yan et al., 2018).
- Korea also has a nuclear-hydrogen programme for the development of a high-temperature gas-cooled reactor and sulphur-iodine thermochemical process (Lee et al., 2009). One of the main expected uses of hydrogen in Korea is steel making using direct reduction of iron ore.
- The Korea Atomic Energy Research Institute developed a 330 MWth integral pressurised water reactor (PWR), SMART, for electricity generation, seawater desalination or district heating. In March 2019, Korea signed an agreement with Saudi Arabia to assess the feasibility of building two SMART units in Saudi Arabia for desalination cogeneration (IAEA, 2019a). Several countries in the Middle East and North Africa are also looking at small nuclear reactors for desalination.
- In the United States, the NGNP Industry Alliance was formed in 2010 to develop the high-temperature gas-cooled reactor (HTGR) and to expand its industrial applications. The Idaho National Lab developed a concept of nuclear-renewable hybrid energy systems (Bragg-Sitton et al., 2016) to integrate nuclear with variable renewable energy sources to improve both the reliability of power and economics. The hybrid energy system includes a nuclear cogeneration application such as an industrial process that utilises heat and/or power from the energy sources to produce commercial-scale product. Several national approaches for nuclear-renewable hybrid energy systems were discussed in a technical meeting organised by the IAEA (IAEA, 2019c). The viability of a hybrid system will depend on the geographical location and the business model.

Several vendor companies for small modular reactors (SMRs) have emerged in the last decade with reactor concepts similar to generation IV reactors and many are aiming at industrial applications market.

In addition to the projected growth in nuclear for power generation as per IEA and IAEA estimates, the deployment of generation IV reactors and SMRs could create more cogeneration opportunities by the middle of the century.

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Chapter 3. Benefits and challenges of developing nuclear cogeneration

3.1. Environmental benefits

3.1.1. *Climate change and greenhouse gas (GHG) emissions*

According to the 2014 Intergovernmental Panel on Climate Change (IPCC) assessment report, it was confirmed through observations such as the rise in the globally averaged land and ocean surface temperature, thawing of snow and ice in polar regions, and rise in the globally averaged sea level that the climate system has been warming due to human activities conducted since the industrial revolution, and that the rate of warming has been accelerating over the past three decades. The combined land and ocean surface temperature was estimated to have increased by 0.85 (0.65 to 1.06) °C from 1880 to 2012 and the global mean surface temperature was projected to increase 4.3 (3.7 to 4.8) °C by 2100 relative to the average over the period 1850 to 1900 under the baseline scenarios, where additional mitigation action is not implemented (IPCC, 2014).

Climate change is having obvious effects on the environment and human beings. It has caused an increase in extreme weather and climate events such as cold and warm temperature extremes, extreme high sea levels and heavy precipitation events in a few regions. It has also affected the quantity and quality of water resources as a result of rainfall change and snow and ice melt in many areas. Many terrestrial and aquatic organisms have shifted their habitat, seasonal behaviour, migration, population and interaction with the ecosystem. A decrease in crop yields has been observed globally. Further warming and associated impacts may differ from region to region. However, without proactive and effective efforts to constrain continuing climate change, the ominous projections by the IPCC leading to severe, wide, irreversible and therefore unadaptable shocks on nature and human beings are likely to be realised globally in the next century (IPCC, 2014).

The IPCC report points out that the anthropogenic GHG emissions such as carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) are the main cause of global warming. It estimated that GHG concentrations and other anthropogenic forcing caused more than half of the increase in average global surface temperature observed from 1951 to 2010. Despite a gradual adoption of climate change mitigation policies in many countries, the total annual anthropogenic GHG emissions, which were 49 $GtCO_2$-eq/year in 2010, have been increasing at an accelerated rate from 1.3%/year between 1970 and 2000 to 2.2%/year between 2000 and 2010.

It is worth noting that although CO_2 is less effective as a greenhouse gas than most of the other GHGs on a molecular basis (e.g. CO_2 is 84 times less effective than CH_4), CO_2 emissions from fossil fuel combustion and industrial processes are the major cause of climate change. This is because it accounts for the majority of not only the total anthropogenic GHG emissions (65% in 2010) but also their increase (78% of increase from 1970 to 2010). Furthermore, CO_2 has a more chronic impact on the global climate system because of its long atmospheric lifetime relative to most of the other major GHGs. Therefore, the most efficient measures to address climate change are drastic cuts of CO_2 emissions from fossil fuel combustion and industrial processes.

The United Nations Framework Convention on Climate Change (UNFCCC), which is an international environmental treaty to combat climate change by limiting average global temperature increases and the resulting climate change, organised its annual Conferences of the Parties (COP 21) in Paris in December 2015 and adopted the Paris Agreement to strengthen the global response to the threat of climate change by keeping a global temperature rise in this century well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5°C. The 2014 IPCC report estimated that under a stringent mitigation scenario set to maintain global warming below 2°C compared with pre-industrial temperatures, global anthropogenic GHG emissions should be reduced to 30-60% of 2010 levels by 2050 and to near zero by 2100. To limit warming even further to 1.5°C, the 2050 emissions should be 5-30% of 2010 levels.

3.1.2. GHG reduction scenario in energy sector

CO_2 emissions from the extraction, transformation and consumption of energy form the majority (70%) of GHG emissions while the non-energy sectors such as industry with feedstock and process emissions, agriculture including animal husbandry, and waste disposal including manure management, represent a stable share of about 30% of global GHG emissions. Energy-related GHG emissions are mostly caused by the combustion of fossil fuels such as coal, oil and natural gas. The energy sector now emits about 33 Gt of the total anthropogenic CO_2 each year, most of which comes from coal consumption, with the remaining coming from oil and gas. Therefore, policies to reduce the use of fossil fuels are the most efficient among various policies to mitigate global climate change, and rely on exploring ways to reduce energy demand, improving efficiency in energy production and use, and expanding low-carbon technologies in energy production (NEA, 2015).

In 2021, CO_2 emissions reached a historic high of 36.3 Gt owing to strong economic growth (IEA, 2022). The CO_2 emissions stagnated between 2014 and 2016 even as the global economy grew. The decoupling of CO_2 emissions and economic growth is attributed to low-carbon technology deployment and improved energy efficiencies, resulting in less demand for coal. However, the dynamics changed in 2017 and 2018 as the deployment of low-carbon options could not keep pace with the economic growth. Nuclear and renewables made an impact with CO_2 emissions growing 25% less than energy demand in 2018, although the global average for CO_2 in the atmosphere reached a record of 407.4 ppm in 2018 (IEA, 2019c).

There is still a long way to go to prevent the most severe consequences of climate change. The IEA (2017) estimated emissions trajectories under two scenarios: the 2°C scenario (2DS) and the beyond 2°C scenario (B2DS) which are defined in Section 2.1. According to the 2DS scenario, the energy-related CO_2 emissions should be reduced to 15 Gt by 2050. This amount is equivalent to 45% of current emissions of 33 Gt and only 27% of the 55 Gt that are projected to be emitted in 2050 under the 6DS scenario, where we continue business as usual without any additional efforts to reduce emissions. The B2DS scenario would require faster and greater reductions in CO_2 emissions compared with the 2DS scenario, with net zero CO_2 emissions by 2060 compared to 2100 under the 2DS scenario.

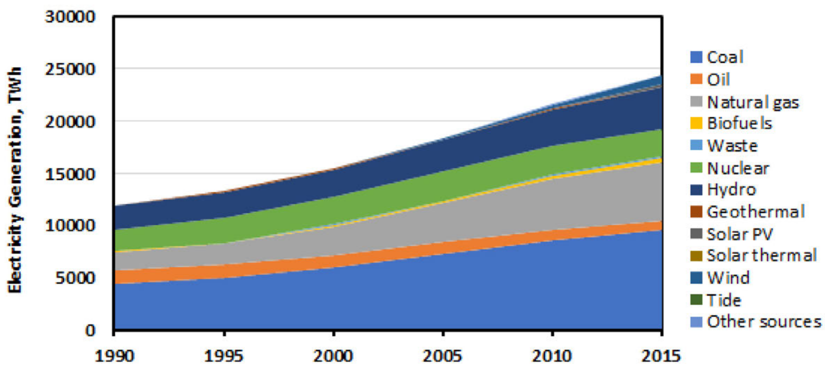
To achieve this ambitious goal, the IEA has developed a series of global low-carbon energy technology roadmaps that aim to develop an implementable strategy to accelerate the development and deployment of new technologies. The nuclear technology roadmap, developed jointly by the NEA and IEA, was updated in 2015 (IEA/NEA, 2015) based on a scenario where nuclear electricity would have a 17% share in 2050 and represent an installed capacity of about 930 GW. Considerations were given to a number of unfavourable factors that have impacted nuclear development since 2010, such as the Fukushima Daiichi accident, the global financial and economic crisis, the shale gas boom, and the failure to set up functioning carbon markets.

3.1.3. Nuclear energy's contribution to GHG reduction scenario

Currently, electricity is generated in relatively large-scale power plants located in fixed sites and operated by large utility companies. In addition, there are low-carbon technologies already established and available for electricity generation such as nuclear energy, hydropower and renewables including solar and wind power. Therefore, electricity is the one sector where almost full decarbonisation is possible. In fact, a virtual decarbonisation of the electricity sector by 2050 is one of the underlying assumptions in the IEA's 2DS and B2DS scenarios. Because electricity can be easily converted into other forms of energy, decarbonised electricity generation may help decarbonise other sectors as shown in the examples of electric transportation and electric heating and cooling. However, fossil fuels were still generating 66% of world electricity in 2015 (39% by coal and 22% by natural gas) and emitting about 40% of global CO_2 emissions (IEA, 2019b).

The largest low-carbon source of electricity globally is hydropower, which has a 16% share of world electricity production (see Figure 3.1 drawn from IEA data [IEA, 2019b]). Hydropower may be further increased in a limited number of non-OECD countries with undeveloped resources. But overall, hydropower will play a lesser role in further carbon emission reductions in the coming decades because of limited resources and other environmental issues involved in hydropower.

Figure 3.1: **Electricity production by technology**



Source: IEA data (IEA, 2019b).

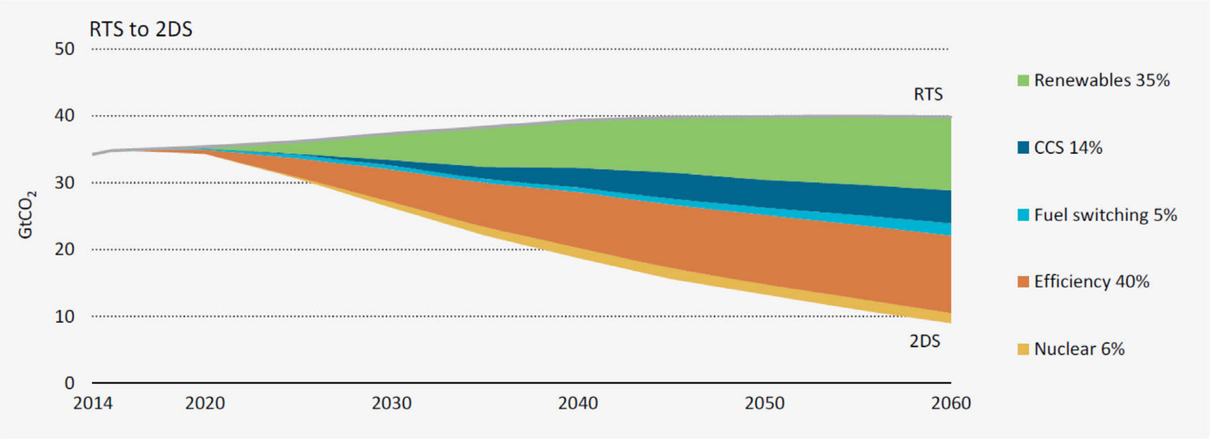
Renewable sources including wind and solar photovoltaics (PV) have dramatically increased their share in electricity generation since 1995 and contributed 5% to global electricity supply in 2015. Much hope has been placed on renewable energy in combating climate change. However, unless substantial progress is made in innovating electrical energy storage technology, renewables cause problems in matching supply with demand because of intermittency and variability in their daily and yearly availability. The necessity of residual generation systems to ensure the reliability of supply increases the costs of electricity production at the system level (see NEA, 2018 and 2019 for further details). Siting issues, such as the need for large tracts of land and a lack of access to the best sites in meteorological conditions, are also barriers to their large-scale deployment.

Another possible alternative is carbon capture and storage (CCS) technology, which is the process of separating and capturing CO_2 from fossil fuel power plants and transporting and storing it into a suitable geological formation. CCS plays an important role in the IEA 2DS scenarios, contributing twice as much as nuclear energy in suppressing carbon emissions by 2050. Although much research has been made, its large-scale commercial deployment has been delayed, projects have been abandoned in several countries, and challenges related to performance, cost and social acceptance still have to be addressed. Several large-scale CCS demonstration plants exist around the world, such as SaskPower's Boundary Dam in Estevan, Canada, Exxon Mobil Corp's Shute Creek plant in Wyoming, and Occidental Petroleum Corp's Century facility in Texas, both in the United States. It should be pointed out, however, that for the topics of interest in this study, namely industrial applications that currently use fossil fuels, CCS would represent in theory a very interesting technology to reduce CO_2 emissions from the heat sector without having to find alternative fuels.

Finally, nuclear energy is a low-carbon energy technology comparable to renewables such as hydro, wind or solar, in terms of lifecycle GHG emissions per unit electricity generation, including direct and indirect emissions (NEA, 2012). The IEA estimated that nuclear power avoided 63 Gt of CO_2 between 1978 and 2018. Without nuclear power, emissions from electricity generation would have been 20% higher and the total energy-related emissions 6% higher (IEA, 2017).

It is therefore clear that a portfolio of low-carbon electricity generating technologies including nuclear energy, CCS, and renewables as well as electricity savings should contribute to the emission reductions necessary to decarbonise the power sector by 2060. Nuclear energy plays a role in the 2DS scenario by sharing a contribution of 6% to the cumulative CO_2 emission reductions relative to the business-as-usual 6DS scenario over the period 2014-2060 (see Figure 3.2).

Figure 3.2: **Emissions reductions required in the power sector by 2060**



Note: $GtCO_2$ = gigatonnes of carbon dioxide.

Source: IEA (2017), *Energy Technology Perspectives 2017*, IEA, Paris.

3.1.4. *Benefits of conventional cogeneration in GHG emission reductions*

Cogeneration produces thermal energy that can be used for lower temperature applications such as district heating and cooling, industrial processes, or desalination as well as power production simultaneously from a single energy source by utilising heat that would be discarded if only electricity were produced. Considering that about two-thirds of energy that is converted to produce electricity is lost as waste heat and this waste heat occupies a large portion of the total primary energy consumption in many countries, cogeneration can dramatically reduce primary energy resource consumption by greatly increasing the efficiency in energy use, from a global average of 37% for conventional power generation up to 58% for cogeneration of power and power (IEA, 2015).

Since GHG emissions are directly proportional to the amount of fossil fuels consumed, cogeneration can also lead to significant reduction in GHG emissions if it is applied to traditional fossil fuel power generation. The US Department of Energy (DOE, 2008) estimated that 60% of the projected increase in CO_2 emissions could be avoided by increasing the combined heat and power (CHP) from its current 9% to 20% share of electric generation in the United States by 2030.

Cogeneration of electricity and heat is a proven and widely used, commercially available technology to satisfy the demand for electricity and heat in industries, buildings, towns and cities. Currently, CHP is providing between 15% and 50% of electricity in Nordic countries such as Denmark. In addition, compared to other measures to reduce emissions, cogeneration is more cost-effective in terms of GHG reductions as well as in power generation because it utilises waste heat rather than just releasing it into the environment. In this regard, the IEA considers cogeneration as part of an integrated approach to meeting 2DS targets across all sectors. Its earlier report predicted that CHP could save 950 Mt/year of CO_2 emissions (2% of energy-related emissions of 42 Gt in the World Energy Outlook Reference Scenario) by 2030 (IEA, 2008).

3.1.5. *Benefits of nuclear cogeneration in GHG emission reductions*

It should be noted that the CO_2 footprint of nuclear power production is mostly caused by the front-end of the fuel cycle, the construction and then later the decommissioning of the plants. Its level is comparable to or even better than most renewable technologies and is almost negligible. Therefore, nuclear energy does not carry any penalties in terms of CO_2 emissions even if it produces electricity and heat separately. But, by producing electricity and heat simultaneously, nuclear energy can reduce the cost required for unit CO_2 emissions reduction due to its higher energy efficiency.

Nuclear energy cannot satisfy all the demand for electricity and heat currently supplied by fossil fuels. Because of its large upfront capital costs (for large light water reactors [LWRs]) and economies of scale, nuclear might be appropriate, i.e. competitive against fossil fuel applications, for significant combined heat and electricity demand. Small modular reactors (SMRs) may certainly address other market segments, if they demonstrate their competitiveness.

The IEA/NEA nuclear technology roadmap also addressed non-electrical applications of nuclear, especially using generation IV reactors, but did not assume that there would be significant deployment of nuclear cogeneration applications up to 2050. But as noted earlier, with stronger commitments by governments to reduce GHG emissions to meet the ambitious climate goals of the Paris Agreement, and with a limited portfolio of technical options to provide low-carbon heat, policy makers may need to look closely at the potential for nuclear to provide not only low-carbon electricity, but low-carbon heat as well.

The IAEA's guidance document (IAEA, 2019) on nuclear cogeneration lists the following benefits.

- Higher efficiency: A nuclear plant in Beznau, Switzerland, operating in CHP mode provides 465 MWth of heat and 135 MWe of electrical power with overall efficiency of 75%.
- Enhanced use of energy, through a better use of energy resources, conservation of fossil fuel and use of heat at the temperatures adapted to the needs.
- Flexibility: an enhanced ability of load following, and the opportunity to operate nuclear plants at full thermal load while meeting the variable demand from the grid.
- Energy security for the users of heat.
- Better economics for the nuclear plant with additional revenue from heat.

*3.1.6. **Benefits of nuclear cogeneration in pollution and waste heat reduction***

Fossil fuel combustion releases CO_2, which is one of the greenhouse gases responsible for global warming. However, CO_2 is not the only hazardous substance coming from the use of fossil fuels. Fuel combustion emits other pollutants such as fine particles, sulphur oxides, nitrogen oxides and volatile organic compounds, which have severe impacts on agriculture and forestry as well as human life. The World Health Organization (WHO) defined such airborne pollutants as a serious threat to human health with high mortality of about 7 million deaths annually, especially in developing countries. Smog pollution in large cities caused by fossil fuel use in transportation and heating has become a subject of concern for policymakers in affected countries and municipalities.

Though some air pollutants are released in the front-end of the nuclear fuel cycle, nuclear energy emits far less than fossil fuel energy sources (NEA, 2015). Pollutant emissions are highly correlated with fossil fuel use, as are CO_2 emissions. Therefore, replacing fossil fuels with nuclear energy in power generation and cogeneration results in the co-benefits of lower pollutants and lower CO_2 emissions. Nuclear energy may also help China and India abate their severe air pollution because the two countries are forecast to have a majority of the 350 GW in new capacity expected worldwide by 2050.

A nuclear power plant that usually has a much larger capacity than a fossil fuel plant releases two-thirds of its generated heat as waste heat into the environment, seas, rivers or atmosphere, depending on its cooling system, if it only produces electricity. Though limited by design and heavily regulated and controlled, the release of waste heat can have an impact on the environment. This impact can be lessened if the nuclear plant operates in a cogeneration mode, since the amount of waste heat released in the environment decreases significantly, with energy efficiency typically improving by more than 20% compared with fossil fuel cogeneration. This can lead to a 30% reduction in waste heat release.

3.1.7. *Contribution to 2DS and B2DS emissions pathways*

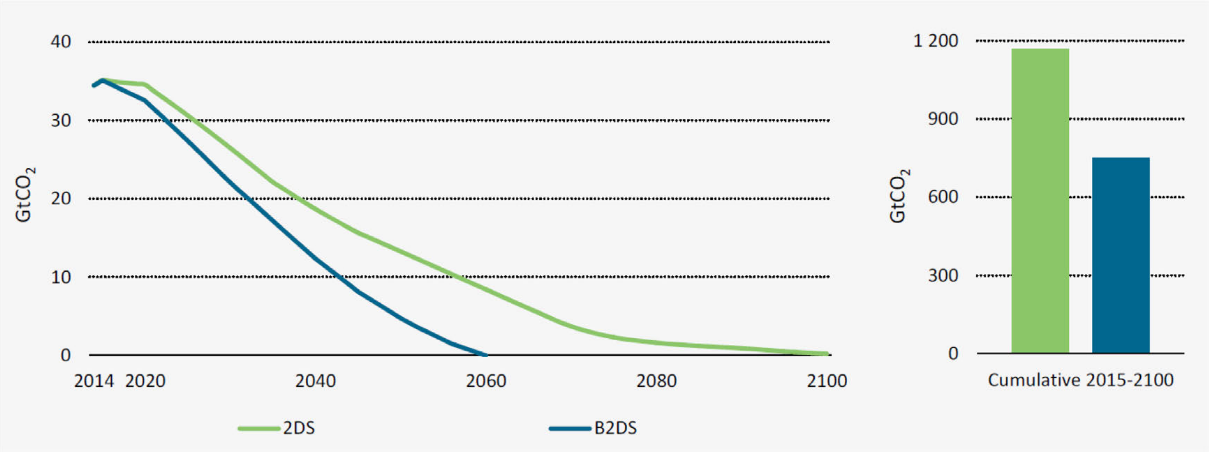
The Paris Agreement (UNFCCC, 2015) aims to strengthen the global response to the threat of climate change by:

> Holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels. (UNFCCC, 2015)

In this statement, there are two targets to limit the global temperature rise: "well below 2°C" and "1.5°C". The meaning of the latter is relatively clear: it is defined as a 50% chance of limiting the global temperature rise in 2100 to below 1.5°C. The meaning of the former target, however, is not as clear. The International Energy Agency (IEA) defined it as shifting the probability of limiting the global temperature rise in 2100 to below 2°C from 50% originally set by the IPCC to 66%. This definition is equivalent to a 50% chance of a 1.84°C rise in 2100 (IEA, 2016). In its latest edition of the *World Energy Outlook*, the IEA also includes a 10% chance of an increase of 3.5° in global temperature in 2100 (IEA, 2021).

With its own definition of "well below 2°C", the IEA provided an assessment of emissions reduction pathways for "well below 2°C" and "1.5°C" targets for the first time in its 2016 World Energy Outlook (IEA, 2016). It is well noted that the temperature rise is mainly determined by the amount of CO_2 accumulated up to that point in time. The IEA estimated emissions trajectories under two scenarios (IAEA, 2017) (see Figure 3.3), namely the 2DS and the B2DS, which are defined in Section 2.1. The remaining energy sector CO_2 budgets between 2015 and 2100 to limit the 2DS and B2DS scenarios are shown on the right side of Figure 3.3. The B2DS requires a 36% reduction in cumulative CO_2 emissions compared with the 2DS by 2100 and net zero CO_2 emissions by 2060. For each of the two scenarios, the emissions trajectory that yields the accumulated budget is shown on the left side of the figure. The illustrated trajectories are the ones that do not require net-negative emissions at any moment up to 2100.

Figure 3.3: **Indicative global energy sector emissions budgets and trajectories for different decarbonisation pathways**



Source: IEA (2017), *Energy Technology Perspectives 2017*, IEA, Paris.

Both the 2DS and B2DS scenarios follow a rapid decarbonisation pathway that does not result in an overshoot of the energy sector's carbon budget in the near term. The IEA pointed out that, while technically feasible, the B2DS describes a future that is a long way from today's energy reality. To close the gap between the current efforts and a 1.75ºC emissions pathway under the B2DS would require a reduction in cumulative CO_2 emissions of around 1.00 Gt across the energy sector up to 2060 relative to the scenario based on the commitments made by the countries (referred to Reference Technology Scenario defined in Section 2.1).

Nuclear is a proven low-carbon energy source immediately applicable for electricity and industrial process heat generation, at least for temperatures within the range of the currently operating water-cooled reactors. The feasibility of process heat applications has been demonstrated through decades of experience providing either district heating, desalination or some other form of process heat. As discussed in Section 2.2.3, various types of generation IV reactors are under development, with generally higher outlet temperatures compared to existing reactors. Also, several vendors are developing SMRs, some of which are based on generation IV concepts. Some of the SMR concepts are targeted for cogeneration applications such as sea water desalination, hydrogen production and industrial heating. For example, in Canada, the oil sands industry is a significant emitter of GHGs and is looking at high-temperature reactors to produce the steam required for the process (refer to Section 6.5). The higher-temperature reactors could open additional opportunities for nuclear cogeneration, thus enhancing the role of nuclear energy in achieving climate change targets under the 2DS and B2DS scenarios.

3.2. Challenges of nuclear cogeneration

3.2.1. Technological challenges

Depending on which nuclear reactor technology is considered for cogeneration, there may or may not be substantial technological obstacles.

Existing reactors

Most of the existing reactors, built before 2000, are either light water (LWR) or heavy water (HWR) generation II reactors. At least 16 reactors of both LWR and HWR types have been used for desalination, and 27 reactors have been used for district heating application. In addition, there have been about eight reactors that were also used at least partly for process heat applications. It is estimated that there are over 750 reactor-years of experience of using LWRs and HWRs in a CHP mode for cogeneration applications (IAEA, 2017). Therefore, there is no need for technology developments to use existing reactors or the new-build generation III/III+ reactors in a cogeneration mode. The technology exists and has already been used for low-temperature applications. One of the advantages of LWRs and HWRs is that heat is extracted from the secondary side, with adequate intermediate heat exchangers to prevent any possibility of contamination.

The integral LWR SMRs with advanced passive safety features might be more acceptable to site near residential or industrial applications compared with the present generation of LWRs, so the development of this type of reactor can offer a promising solution for low-temperature cogeneration. Coupling with heat applications will be easy, as the solutions will be the same as for large LWRs. It will be possible to have a "plug-in" connection to existing water or steam networks in substitution of fossil fuel-fired plants.

Most of the current and past cogeneration applications are based on LWR type reactors and use only a fraction of thermal energy from the reactors. Although there are no technological challenges, other factors including the geographic location of the nuclear power plant relative to the users of thermal energy, economics and public acceptance are important considerations and could have limited the extent of cogeneration to date. Coupling a nuclear plant with an industrial facility and related safety issues are also important for licensing (IAEA, 2019). All issues listed above could be specific to each individual location and application and could determine the viability of a particular cogeneration application.

Generation IV reactors

Six types of generation IV reactor concepts are being developed under multilateral collaboration enabled through the Generation IV International Forum (GIF). They are the:

- gas-cooled fast reactor (GFR);
- lead-cooled fast reactor (LFR);
- molten salt reactor (MSR);

- sodium-cooled fast reactor (SFR);
- supercritical water-cooled reactor (SCWR);
- very high temperature reactor (VHTR).

Generation IV reactors have higher outlet temperatures compared to LWRs, making them better suited to higher-temperature industrial applications as illustrated in Section 2.2.3. In particular, the VHTR is targeted at industrial process applications. GIF has identified the main technological barriers that have to be overcome for the development of generation IV reactors, and has defined the roadmap for the required developments (GIF, 2014). This is a long process requiring intermediate steps, or at least an intermediate scale demonstration. For some technologies, the process even requires starting with a small-scale test reactor. The industrial deployment of these reactors is expected by 2050, resulting in a cogeneration mode that does not raise any specific issues during operation. The experience of cogeneration obtained with initial deployment of high-temperature, gas-cooled reactors (HTGR) will have paved the way for high-temperature cogeneration with other types of generation IV reactors.

As for other types of nuclear systems, designs with safety features allowing siting close to applications and with relatively small powers will be more adapted to the cogeneration applications.

High-temperature gas-cooled reactors (HTGR)

Modular HTGR technology benefits from the legacy of past industrial developments of this type of reactor in several countries and of technology developments performed under the GIF collaboration. No intermediate step, such as the construction and operation of test reactors or intermediate scale demonstration plants, is necessary: the HTGR technology is mature enough to go directly to the design, licensing and construction of a first-of-a-kind (FOAK) commercial system. This is presently being achieved in China, where two 250 MW modular HTGRs started operating in 2021.

Nevertheless, apart from a few low-temperature experiences, there has been no industrial application of nuclear cogeneration. Before envisaging a large deployment of high-temperature nuclear cogeneration for industrial applications, it is necessary to demonstrate the capability of HTGRs to perform cogeneration in an industrial environment and to address process heat users' requirements, which are quite different from utilities' usual requirements. This demonstration will require designing the FOAK system, licensing it, building and operating it in a cogeneration mode, supplying process heat to industrial users. The cost for the design, licensing, procurement, construction and a few years of demonstration operation of the FOAK will be about USD 3 billion. Such a project could be fully implemented by 2030.

Although no core technology is missing for the development of the FOAK system, a large-scale helium loop will be necessary for the qualification of reactor critical components in representative conditions. The design and construction of this loop should be planned early on, as the test results of components are needed for licensing and should be available early enough to be able to launch procurement. The cost of this loop is expected to be about USD 100 million.

On the other hand, HTGRs have been operated with limited instrumentation due to the harsh environment inside the reactor. Though not absolutely necessary, the development of additional high-temperature instrumentation will facilitate the licensing of future commercial plants and possibly allow an increase in their performance, as long as knowledge of the conditions inside the reactor improves.

The HTGR tristructural-isotropic fuel is very specific and requires special fuel fabrication facilities. For the FOAK demonstration programme, it is possible to have the fuel procured from an existing manufacturing facility and to benefit from the results of the extensive qualification programme of this fuel. However, for further commercial deployment, additional facilities should be created and the fuel produced by these facilities should be qualified (cf. the progress in the Advanced Gas-cooled Reactor fuels programme) (INL, 2017). Fuel qualification is a long process and requires the development of pre-industrial fabrication, irradiation and post-irradiation examinations. The whole programme of fuel development and qualification should therefore be planned early enough. Its cost will be in the range of USD 100-200 million.

The first process heat applications of HTGRs will be, as already mentioned, "plug-in" applications on existing steam distribution networks, which operate at temperatures that do not exceed 550°C. Then other applications can be developed with other heat transport fluids at temperatures between 550 and 700°C. New types of heat exchangers will have to be developed for such applications.

Very high temperature reactors (VHTR)

The key development required for HTGR technology to step into the domain of higher-temperature applications concerns materials for the reactor vessel, for the internals and for the heat exchangers. Metallic materials and composites are being considered for the VHTR, which is one of the six generation IV concepts. The qualification of advanced materials for nuclear application will be long and rather expensive (in the range of USD 100 million). Manufacturing methods (machining, forming and assembling) for such advanced materials, for which little or no industrial experience exists, will have to be developed. Components using these materials will have to be designed and tested. One of the most challenging components is the intermediate heat exchanger interfacing between the primary circuit and the power conversion system. It is subjected to very large thermal stresses in steady-state and transient conditions, which makes its design challenging. It will have to be tested in a helium loop with representative conditions. The fuel developed for HTGRs is far from its operational limits, both in normal and accident conditions. It will likely be kept for VHTR operation, but it will be necessary to qualify it for such conditions.

Developing a VHTR concept will not make sense without the development of heat transport techniques for very high temperatures, which do not exist in industry at the moment. Development of the interface with industrial heat users including intermediate heat exchangers, ducts, valves and associated heat transfer fluid is one of the key objectives for the VHTR development (GIF, 2014). The other area that needs further research and development is the safety analysis of coupled nuclear processes for industrial sites using process heat.

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Chapter 4. **Business models for nuclear cogeneration**

4.1. **Methodology**

4.1.1. Market segmentation

Before any analysis of the possible business models for nuclear cogeneration, it is useful to identify which markets to target. In doing so, one must identify the most important parameters that refine the market's boundaries, and then agree on a certain definition of market segments.

Cogeneration plants operate in two markets, electricity and heat. Yet these two markets are not equally segmented. In most countries, power grids are developed to a broader extent than heat networks. Therefore, the cost of "reaching" a new electricity consumer is negligible compared with the cost of developing infrastructure to supply heat to new clients. In addition, power production can be offset by other power plants from the grid whereas heat production cannot (each heat production plant usually has its own backup solution). For these reasons, market segments for cogeneration derive from constraints related to heat production more than electricity.

The most important parameter defining cogeneration market segments is temperature. When considering nuclear power as a heat source, it is therefore important to take into account the thermal capabilities and limits of the various reactor technologies.

Other significant parameters are worth mentioning: the amount of heat needed, specific safety requirements, plant adaptation to load transients, plant availability and reliability, heat transport technological limits, and, very importantly, the licensing of a nuclear plant coupled with a cogeneration facility. These parameters are discussed more in Section 4.2, where they are used to define market segments in the context of nuclear cogeneration.

4.1.2. Analysing possible business models

Combined heat and power (CHP) plants usually have at least two categories of clients: end users for heat and power (either industrial applications or district heating end users) and the power grid to trade excess power production and demand. In this report, the emphasis is placed on the business model of cogeneration plants rather than the end users or the power grid. Still, other stakeholders may play a crucial role in the value chain. Indeed, the issues related to heat transport (infrastructure costs, losses, etc.) prompt cogeneration plants to settle close to their end users. Therefore, CHP plants are often part of industrial clusters. Within these clusters, additional financial and strategic constraints may lead to various complex energy management systems and ownership models for the CHP plant.

The first step in analysing business model possibilities for nuclear cogeneration is then to investigate the degree of integration of the plant among stakeholders.

The second step is to describe the value chain of cogeneration using the Business Model Canvas. The energy manager is a key stakeholder of the value chain in the industrial clusters. Its role between the CHP plant and the end users is crucial to understanding how the CHP plants can efficiently create value. Therefore, the Business Model Canvas should be completed for the energy manager rather than the plant's owner. This also makes it easy to compare various integration strategies.

After comparing integration strategies and business model canvases, the next step is to focus on financial issues. Financing a nuclear cogeneration plant raises additional challenges and opportunities compared to electricity-only nuclear plant, as more stakeholders are involved. A review of existing ownership models is necessary to discuss the model most likely to emerge.

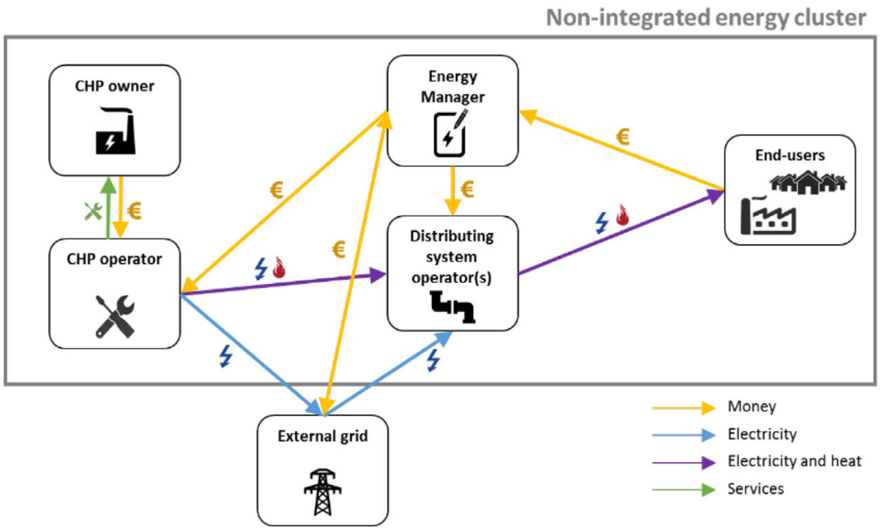
4.1.3. *Integration models*

These models and the associated on-site integration of stakeholders are described in the following sections, and are illustrated in Figures 4.1, 4.2 and 4.3. They are used as templates to describe the integration models most likely to emerge in each market segment. These templates were derived from actual cases of cogeneration plants – whether nuclear or conventional – located within industrial clusters (Ståhl et al., 2015).

Integration model 1: Non-integrated energy clusters

In this energy management system (see Figure 4.1), each core activity (energy contract management, energy distribution, plant operation, etc.) is the business of a specific company. On one side, end users – be they industrial companies or individuals (e.g. households benefiting from district heating) – receive energy in the form of heat and/or electricity from one or more distribution system operators (the heat and electricity networks can be separate). When they pay their energy bills, however, they will pay the energy manager, which is a different company. On the supply side, the CHP operator gets paid by both the CHP owner (to operate and maintain the plant) and the energy manager (for feeding the distribution networks with heat and electricity and for sending any surplus electricity to the grid). Thus, in this model, the energy manager plays a central role: it is in charge of managing cash flows related to energy production, distribution and consumption.

Figure 4.1: **Organisation chart of a non-integrated energy cluster**



Source: LGI Consulting.

Actual industrial cases

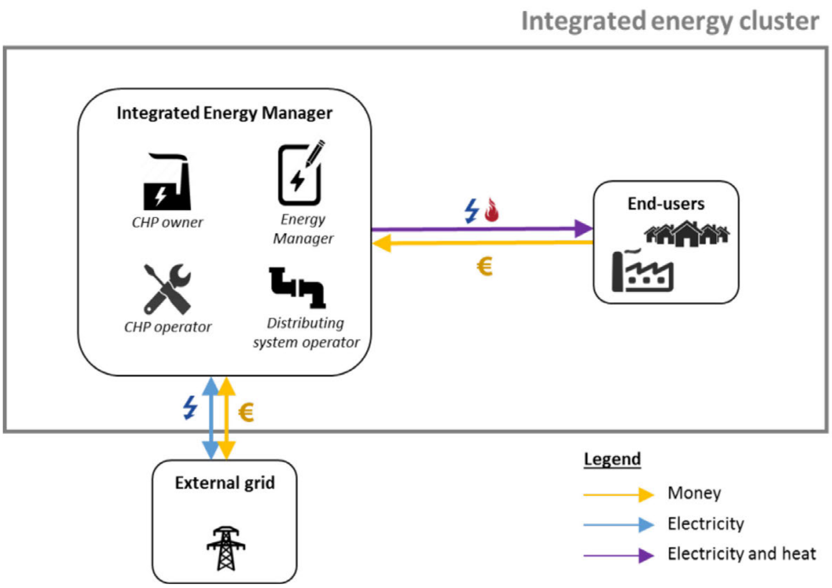
In the chemical industry, the Chemelot Park (Netherlands) is an example of a non-integrated energy cluster. The conventional CHP plant is owned by Essent (now RWE), operated by EdeA, which is also in charge of distributing steam and electricity within the cluster. EdeA produces and distributes various industrial gases. USG (Utility Support Group) is the energy manager of the cluster, and dozens of industrial companies form the group of end users.

In nuclear district heating, the Beznau cogeneration plant (Switzerland) can be considered part of a non-integrated energy cluster. Indeed, Axpo is the owner and operator of the nuclear power plant, but power is distributed by the Swiss grid and hot water is supplied by Refuna AG to the end users (households) through the heating network.

Integration model 2: Integrated energy clusters

In this energy management system (see Figure 4.2), the same company owns and operates the CHP plant and the local distribution networks. Cash flows within the cluster are thus limited to the bill payments from end users and the sales and purchases of the grid electricity balance.

Figure 4.2: **Organisation chart of an integrated energy cluster**



Source: LGI Consulting.

Actual industrial cases

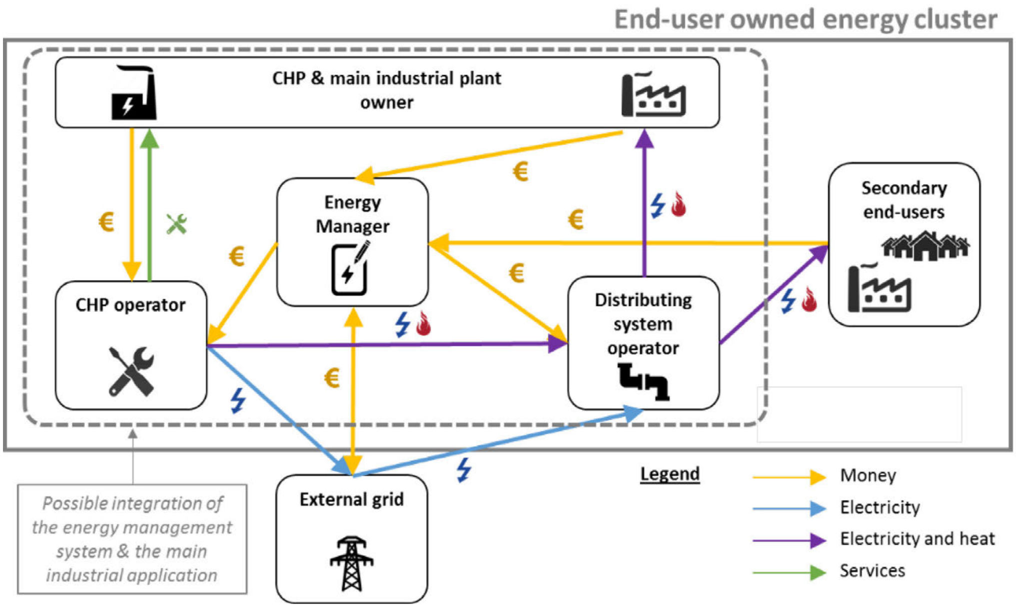
The Niederau Industry Park (Germany) is an example of an integrated energy cluster. A single company (Nuon, now part of Vattenfall) owns and operates the CHP plant, and also provides the group of end users (industrial companies) with additional services (grid management, gas distribution, water supply, etc.).

In nuclear district heating, the Chinese, Russian and Slovakian experiences can be considered as examples of integrated energy clusters since state-owned companies own, operate and distribute heat to the housings. Yet, the Bohunice nuclear cogeneration plant (Slovak Republic) is not a fully integrated energy cluster anymore. Since Slovenské Elektrárne (former state-owned company) has been privatised, some small companies oversee the last stage of heat distribution for most end users (Slovenské Elektrárne remains a fully integrated provider for some industrial clients).

Integration model 3: End-user owned energy clusters

In this energy management system (see Figure 4.3), one of the end users (usually the largest industrial application of the cluster) also owns the CHP plant. This may result from a strategy to secure the supply of energy (heat and power) and enable the industrial plant to operate continuously. Depending on the technical skills of the main end user and its strategy, it may also manage all energy cash flows in the cluster, operate the CHP plant, and own and/or operate the distributing system. This results in different levels of integration of the cluster.

Figure 4.3: **Organisation chart of an end-user owned energy cluster**



Source: LGI Consulting.

Actual industrial cases

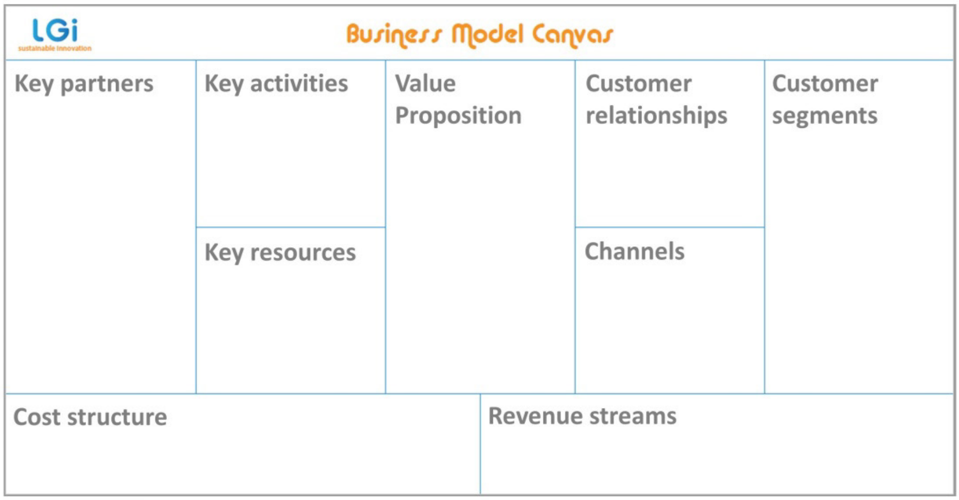
In the chemical industry, the Marl Chemical Park and the Bayer Bitterfeld Park (Germany) are two examples of end-user owned energy clusters. Evonik-Degussa, a leading company in specialty chemicals, owns one of the conventional cogeneration plants of the Marl Chemical Park. These plants and the distribution networks are operated by a subsidiary of Degussa. Bayer Bitterfeld, a subsidiary of the chemical and pharmaceutical company Bayer AG, owns power and natural gas supply networks for the Bayer Bitterfeld Park. Yet it does not operate it or manage energy contracts.

To a certain extent, some examples of nuclear cogeneration applications could be assimilated to end-user owned energy clusters. In Canada, the Bruce Nuclear Power Plant fed an industrial park with steam until 2006. Among industrial applications (heavy water production plant, plastic film manufacturer, greenhouse, ethanol plant, alfalfa plant, apple juice concentration plant, agricultural research facility), the production of D_2O was the main activity. The D_2O production plant and the nuclear power plant used to be owned and operated by the same company since heavy water was one of the products of the nuclear power plant.

4.1.4. *Business model canvas*

Several business model canvas methodologies can be used to assess and describe the value creation of a stakeholder. Osterwalder's canvas (Osterwalder and Pigneur, 2010) is the most popular. It consists of nine building blocks as shown by Figure 4.4 and is briefly described below. This canvas, which was widened here to include also generic nuclear cogeneration applications, was originally used in the EU-funded research programme called NC2I-R to assess the business model of high-temperature reactors (HTR) (Ståhl et al., 2015) The following (see Figure 4.4) describes each of the nine blocks in the case of cogeneration and from the point of view of the energy manager.

Figure 4.4: **Business model canvas**



Designed by: Business Model Foundry AG, *The makers of Business Model Generation and Strategyzer*
Adapted by: LGI Consulting

The customer segments define the different groups of people, companies or organisations that the stakeholder aims to reach and serve. In the case of cogeneration, two different segments can easily be identified: the industries located within the energy cluster and, in the case of district heating, the housings connected to the heating network.

The relationship of the energy manager with those customers is either a direct business-to-business (B2B) relationship (onsite interaction with industrial customers) or a remote business-to-customer (B2C) relationship (web platform, hotline for individuals).

The value proposition is the set of products and services that are valuable for the customers. In cogeneration clusters, the energy manager ensures the supply of heat and power 24-7 with given characteristics (voltage, intensity, temperature, thermal power, etc.) and at the best prices. In this way, it provides comfort to housings and enables industries to focus on their core business.

To deliver its value proposition, the stakeholder may reach the customers through different channels. In the case of cogeneration, those channels depend on whether the energy manager's cluster is integrated or not (see Figure 4.1, Figure 4.2, Figure 4.3).

The key activities are the most important things a stakeholder must do to make its business model work. The main activity of the energy manager in a cogeneration cluster is certainly to negotiate contracts with end users (industries, housings). It also buys electricity from the grid and may have other important activities depending on the level of integration in the cluster (see Table 4.1 and Table 4.2).

The key resources are the most important assets required to make the business model work. Any energy manager should have good negotiation and commercial skills and a legal backing. Depending on the level of integration in the cluster, there may be other key resources.

The key partners represent the network of suppliers and partners on which the stakeholder relies. The energy manager of a cogeneration cluster essentially relies on the CHP operator, on the distribution system operator(s), and on the external grid to balance local power production.

The cost structure describes all costs incurrent to operate the business model. For any energy manager, these costs include the power bought from the grid. The rest of the cost structure depends on the level of integration (see Table 4.8 and Table 4.9).

Finally, the revenue streams represent the incomes from the value sold to the customers. Regardless of the level of integration, those revenues come from industrial contracts, energy bills from housings and sales of power to the grid.

Table 4.1 shows the business model canvas of the energy manager in the case of a non-integrated cluster. The specificities compared with an integrated cluster are shown in bold. For instance, non-integrated energy managers have additional partners (the CHP owner or operator, the distributing system operator[s]). They also have specific costs (the energy bought from the CHP operator and the distribution fees since the channels used to deliver value to the customers are non-proprietary).

Table 4.1: **Business model canvas of the energy manager in a non-integrated cluster**

CASE N°1: ENERGY MANAGER IN A NON-INTEGRATED CLUSTER				
KEY PARTNERS	**KEY ACTIVITIES**	**VALUE PROPOSITION**	**CUSTOMER RELATIONSHIPS**	**CUSTOMER SEGMENTS**
CHP owner or operator **Distributing system operator(s)** External grid	Negotiate contracts with end-users (industries, housings) Buy electricity from the grid	Ensure the supply of heat and electricity 24-7 with given characteristics (V, I, T°, P, etc.) Supply energy at best prices Provide comfort to housings Enable industries to focus on their core business	Direct B2B relationships (onsite) Remote B2C services (web platform, hotline)	Industries located in the cluster and/or Housings connected to the district heating network
	KEY RESOURCES		**CHANNELS**	
	Negotiation & commercial skills Juridical workforce		Local & **non-proprietary** heat /power distributing network	
COST STRUCTURE	**Energy bought from CHP operator** **Distribution fees** Purchases of electricity balance from the grid		Contracts from industries Energy bills from housings Sales of surplus electricity to the grid	**REVENUE STREAMS**

Designed by: Business Model Foundry AG, *The makers of Business Model Generation and Strategyzer*
Adapted and completed by: LGI Consulting

Table 4.2 shows the business model canvas of the energy manager in the case of an integrated cluster (the energy manager owns and operates the CHP plant and the distribution networks). The specificities compared with a non-integrated cluster are shown in bold. For instance, integrated energy managers have fewer partners, since most functions are internalised (distribution system, technical workforce, CHP plant). Operating the CHP plant and the distribution system is an important additional activity. Since the plant and the distribution system are proprietary, the cost structure accounts for the corresponding investments and operation and maintenance costs.

Table 4.2: **Business model canvas of the energy manager in an integrated cluster**

CASE N°2: INTEGRATED ENERGY CLUSTER				
KEY PARTNERS	**KEY ACTIVITIES**	**VALUE PROPOSITION**	**CUSTOMER RELATIONSHIPS**	**CUSTOMER SEGMENTS**
External grid	Negotiate contracts with end-users (industries, housings) Buy electricity from the grid **Operate CHP plant and distribution network**	Ensure the supply of heat and electricity 24-7 with given characteristics (V, I, T°, P, etc.) Supply energy at best prices Provide comfort to housings Enable industries to focus on their core business	Direct B2B relationships (onsite) Remote B2C relationships (web platform, hotline)	Industries located in the cluster and/or Housings connected to the district heating network
	KEY RESOURCES		**CHANNELS**	
	Negotiation & commercial skills Juridical workforce **Distributing system** **Technical workforce** **CHP plant**		Local & **proprietary** heat /power distributing network	
COST STRUCTURE	Purchases of electricity balance from the grid **Distributing system investment** **CHP investment** **O&M costs (CHP & networks)**		Contracts from industries Energy bills from housings Sales of electricity surplus to the grid	**REVENUE STREAMS**

4.1.5. *Ownership models*

Along with the various on-site integration models, nuclear cogeneration can rely on different financing and ownership solutions. A European Union-funded project investigated these based on existing models for electricity generating nuclear power plants (Ståhl et al., 2015). This report briefly describes the three most common ownership models. In the European study, some important implications related to the risks of energy price volatility are also stressed from the point of view of the main three stakeholders, which are:

- the nuclear utility (public or private company in charge of delivering and commercialising electricity to the grid in electricity generating nuclear power plant projects);
- the end users (potential customers of the cogeneration projects: industries, or housings representatives in the case of district heating);
- vendors, suppliers and contractors (technology and system providers and companies offering engineering, procurement and/or construction management).

Ownership model 1: Standalone entity

In this ownership model, the owner of the power plant is usually the utility company and is generally responsible for most of the financing. Contractors and suppliers are in charge of the construction; they sell equipment and services to the owner. The end users engage in a classical customer-provider relationship with the owner: they purchase energy from the utility at prices that are either set by long-term contracts or depend on a market. For example, the Loviisa 1 and 2 plant units (Finland, see case study in Section 6.1) are standalone entities.

In this ownership model, financial risks are mainly shared between the utility and the contractors: cost overruns or delays in the plant construction may represent high financial risks for the contractors (turnkey delivery). Delays could also financially impact the utility (loss of earnings) which is also exposed to the market fluctuation while operating.

Ownership model 2: Co-owned generation plant

There are two main ownership models in which several stakeholders are involved in the financing of the plant.

The first one is called the Mankala model: the plant is a standalone entity owned by a dedicated company. The utility company, the end users (industrial company, municipalities, etc.) and the vendors are usually the shareholders of this Mankala company and as such hold rights to the power and heat production of the plant based on their equity shares. The shareholders are committed to buy the power and heat at cost price, so the company operates as a zero-profit co-operative. Thus, the market risks are transferred to the owners of the company. This model is widely used in the Finnish power sector (TVO and PVO are Mankala companies).

Apart from the Mankala model, co-ownership by several utilities has existed for a long time (e.g. Chooz A, Fessenheim in France).

Other examples of co-owned power plants include vendor-equity funded projects. In this model, the technology suppliers bring equity to partially finance the plant construction in exchange of having their technology deployed. Once the plant is commissioned, the financial risks related to construction no longer exist. This ownership model may then include exit options for the vendors if they agreed with the main owner not to support market risks during operations. Recently, several nuclear power plants have been or are expected to be funded by vendor equity (Visaginas in Lithuania involving Hitachi GE, Barakah in the United Arab Emirate involving Korea Electric Power Corporation [KEPCO] or Hinkley Point C, United Kingdom).

Ownership model 3: Build-own-operate (BOO)

In this ownership model, a vendor is responsible for the design, financing, construction, operation, maintenance and decommissioning of the power plant. The vendor owns the plant and has to support all financial risks, including those related to construction and market. Countries willing to launch a nuclear programme consider the build-own-operate model as a good opportunity to benefit from the vendor's experience, training and financial support. Rosatom is currently building the first nuclear power plant in the Republic of Türkiye (Akkuyu) under a build-own-operate partnership.

4.1.6. Role and risks in various ownership models

Depending on the specificities of each cogeneration projects, different ownership models may come up. Table 4.3 and Table 4.4 summarise the role of the main stakeholders and associated financial risks in the three cases described previously.

Table 4.3: **Role of the three main stakeholders in various ownership models**

Roles	Standalone entity	Co-owned generation plant	Build-own-operate
Nuclear utility	Full ownership	Partial ownership	Purchase energy
End users (industry, housings)	Purchase energy	Purchase energy/partial ownership	Purchase energy
Vendors, contractors, technology suppliers	Sell equipment and services	Sell equipment and services/partial ownership	Full ownership

Source: Ståhl et al. (2015) and Auriault and Ståhl (2015).

Table 4.4: **Risks for the three main stakeholders in various ownership models**

Risks	Standalone entity	Co-owned generation plant	Build-own-operate
Nuclear utility	Depends on the market, may be high	Moderate	Low
End users (industry, housings)	Low	Moderate	Low
Vendors, contractors, technology suppliers	May be high (turnkey delivery)	May be high (turnkey delivery, not part of the co-owned company)/moderate (co-owner)	Depends on the market, may be high

Source: Ståhl et al. (2015) and Auriault and Ståhl (2015).

4.2. Market segments: Different nuclear technologies for different applications

The most important constraints and parameters that shape the boundaries of nuclear cogeneration markets are discussed in the following sections. Most of them deal with heat requirements and nuclear reactor technologies, but other often cited criteria (safety requirements, load transients and plant availability) must be considered, too.

Temperature range for heat applications

The temperature required by different heat applications covers an exceptionally large spectrum, from a few dozen degrees up to more than 1 600°C. With existing technologies (generation II and III reactors presently operating or in construction) or with technologies that could be developed in the next decades (generation IV systems), the whole spectrum cannot be fully addressed. The core outlet temperatures for these types of nuclear reactors are:

- LWRs (light water reactors) ~ 300°C;
- SCWR (supercritical water reactor), SFR (sodium-cooled fast reactor), LFR (lead-cooled fast reactor) ~ 500°C;
- HTGR (high-temperature gas-cooled reactor), GFR (gas-cooled fast reactor), MSR (molten salt reactor) ~ 750°C;
- VHTR (very high temperature reactor) up to 900-1 000°C.

The primary coolant cannot be used directly for non-nuclear applications and one or even two heat exchange barriers have to separate the primary circuit from non-nuclear applications. Therefore, the maximum temperature that can be expected for heat applications is between 50 and 100°C below the core outlet temperature.

So all types of reactors could a priori contribute to cogeneration, some for a limited range of applications, other ones for a wider range, but none can fully supply the industrial heat in the highest range of temperature, for instance for cement or glass fabrication, which require temperatures of 1 400-1 500°C. Nevertheless, even in such applications, nuclear energy can contribute to pre-heating, significantly reducing the CO_2 emissions of these processes and sparing significant quantities of fossil fuel.

Moreover, the spectrum of temperatures required for heat applications is not set forever. Industrial processes are evolving, with the general trend being a reduction in their temperature and energy consumption. This will help widen the domain of deployment of nuclear cogeneration, without waiting for the development of challenging advanced systems such as VHTRs. Ten years ago, one of the main motivations put forward for developing VHTRs was the potential of such nuclear systems to be used for CO_2-free mass production of hydrogen. At that time, thermochemical water-splitting processes that required an operating temperature ~900°C were considered for such production. Presently, steam electrolysis requiring only 650°C is also considered and the use of HTGR technology is sufficient to provide the necessary heat and electricity. Even the standard hydrogen production process, steam methane reforming, which is usually performed at 850-900°C, can now be operated at 650°C thanks to a new technique with continuous extraction of hydrogen through membranes. While this process is not CO_2-free, using the heat provided by a HTGR allows significant reductions in its CO_2 emissions.

If at some point nuclear energy enables hydrogen production at a competitive cost, this can also be a driver for significant evolution in many industrial processes, as hydrogen can substitute the syngas that is presently widely used as reducing agent.

Conventional industrial processes usually have a relatively short lifetime (the average in the chemicals industry is about 15 years). Therefore, nuclear reactors, now designed for a 60-year time frame, should be flexible enough, if they are dedicated to cogeneration, to be able to adapt to the changing landscape of industrial processes.

Heat amount needs

The quantity of heat required is always limited to the local needs around the heat generation unit (e.g. heat needs for district heating in an urban area or for a large industrial site), as heat transport over long distances would be penalised by the high cost of the heat transport systems and heat losses. These needs rarely exceed a few hundred MW. Therefore, smaller reactors are more adapted to cogeneration than large reactors. For large reactors, heat could be an opportunistic by-product of electricity generation, if some significant heat consuming activities exist in their neighbourhood.

Specific safety requirements

Current industrial reactors are usually located far from large urban or industrial zones, which is not favourable for marketing the heat they produce. For cogeneration, setting up the nuclear plant close to applications would need to be acceptable by nuclear regulators (e.g. see the regulatory frameworks in the case of hydrogen production [Forschungszentrum, 2007]). From this point of view, small modular reactors (SMRs) have a specific advantage, as their safety design, usually based on a passive safety concept, might allow reducing the size of the emergency planning zone, or even suppressing it. At the same time, the nuclear cogeneration plants are also expected to comply with general regulatory frameworks for CHP plants (Gochwenoitr, 2003) (Kasarabada and O'Neal, 2016).

Safety requires a physical separation between the nuclear heat generation and the process heat applications, to eliminate risks of interaction between the two types of processes (e.g. a blast in a chemical plant inducing a nuclear accident, or nuclear fission product release inducing radio-contamination of non-nuclear processes). The elimination of such risks of interaction is not only obtained by introducing physical barriers between the nuclear reactor and the conventional process heat applications, but also by imposing a minimum distance of at least a few hundred metres between them. Therefore, an efficient heat transport system is necessary between the nuclear reactor and the heat applications.

Adaptation to load transients

Nuclear reactors have a limited capacity to accommodate load variations. For electricity generation, the load being usually averaged on a large interconnected grid, such variations are limited and can be handled by multiple production units. Heat demand, on the contrary, is always local, without interconnection, and is addressed by a single nuclear unit or, in some cases, by a few units. Depending on the specificity of each application, heat load variations could therefore be larger than electric load variations. Such variations could be partially damped by the reactor itself (for instance in the case of an HTGR, which has a very large thermal inertia) or by the thermal inertia of the heat distribution network. They could also possibly be accommodated without varying the reactor power by changing the distribution of the energy produced by the reactor between electricity generation and heat supply, or by variable distribution of constant heat production on different applications (in particular using production of energy products like hydrogen as a way to store energy). As a last resort, it is always possible to add some thermal heat storage capacity. Each of these alternative solutions for matching heat demand can contribute to the flexibility of nuclear cogeneration, but they have a cost that must be included in the assessment of the economic viability of nuclear cogeneration.

Availability and reliability requirement

In modern nuclear reactors, the availability and reliability can be rather high, with availability factors significantly above 90%. Nevertheless, for present industrial LWRs, this high availability results from the experience of many years of operation that allowed minimising the duration of planned shutdowns and reducing the number of unanticipated shutdowns. It is clear that new types of reactors, more adapted to the needs of cogeneration of heat and power, will have to follow similar learning curves in terms of the availability factor. Whether heat comes from conventional cogeneration plants or boilers, or from a nuclear plant, if the applications require high availability, backup facilities will have to be added to the nuclear plant. The cost of the backup might be higher than in the case of conventional fossil fuel-fired heat plants: in heat distribution networks operated on industrial sites, the heat is often – but not always – supplied by several small fossil fuel-fired units distributed on the whole site. If 100% availability is required by the applications, it can be obtained by adding one or two small units for surplus power on the site, representing only a small fraction of the installed power. If the site is fed by a single nuclear reactor, to secure 100% availability, an equivalent surplus power, obtained from fossil fuel combustion or nuclear energy is necessary. The need for backup will therefore have to be studied on a case-by-case basis, depending on the minimum heat supply required in any case by the heat applications, and will have a significant influence on the economic viability of nuclear cogeneration plants.

Capacity of heat transport technologies

As already mentioned, the heat produced by a nuclear reactor cannot be used in the immediate vicinity of the reactor and should be transported over distances between a few hundred metres and a few kilometres. There is a large experience of heat transport on industrial sites or for district heating applications. Nuclear cogeneration systems could be easily substituted for conventional cogeneration plants in a "plug-in" mode, without changing any existing infrastructure of heat distribution networks.

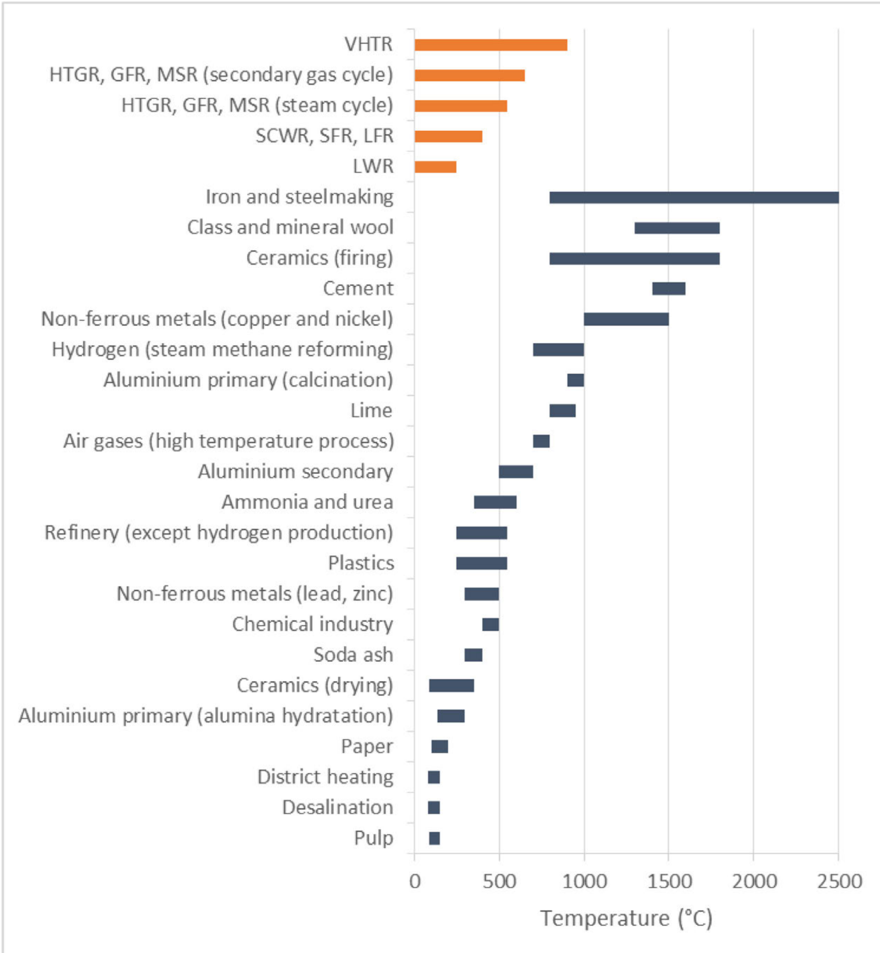
But like nuclear reactors, heat transport systems have some temperature limits, due to the properties of the heat transfer fluid (stability at high temperature), to the mechanical behaviour of the materials of the pipes, which deteriorates at high temperature and might require the use of more expensive materials, and to the interactions between the fluid and the pipe walls (corrosion). The common industrial heat transfer fluid used in heat transport systems is water/steam, but occasionally organic liquids, silicone liquids or molten salts are also employed. These alternative fluids have the advantage of allowing operation at atmospheric pressure, contrary to steam. Nevertheless, the required pumping power, as well as the cost of these fluids and of compatible piping, must also to be considered in the selection of the heat transfer fluid. Steam networks are commonly used on industrial sites up to 550°C, organic and silicone fluids cannot exceed ~400°C, while molten salts can be used up to 700°C.

Beyond 700°C, there is no industrial solution for the transport of large quantities of heat over significant distances. The heat is presently produced in situ, for instance by heating the chemical process chamber walls from outside by burning fossil fuel or even by producing heat directly by internal combustion inside the reaction chamber (e.g. cast iron making in blast furnaces). Consequently, using nuclear energy for heat applications beyond 700°C requires not only appropriate nuclear systems but appropriate heat transport technologies.

Market segments and marketing strategy

This report has shown that the heat market can be split into a series of temperature ranges, based on the temperature requirement of the end users and on the temperature provided by each reactor technology. Those temperature ranges are depicted in Figure 4.5.

Figure 4.5: **Process temperature ranges by industrial application and reactor capabilities**



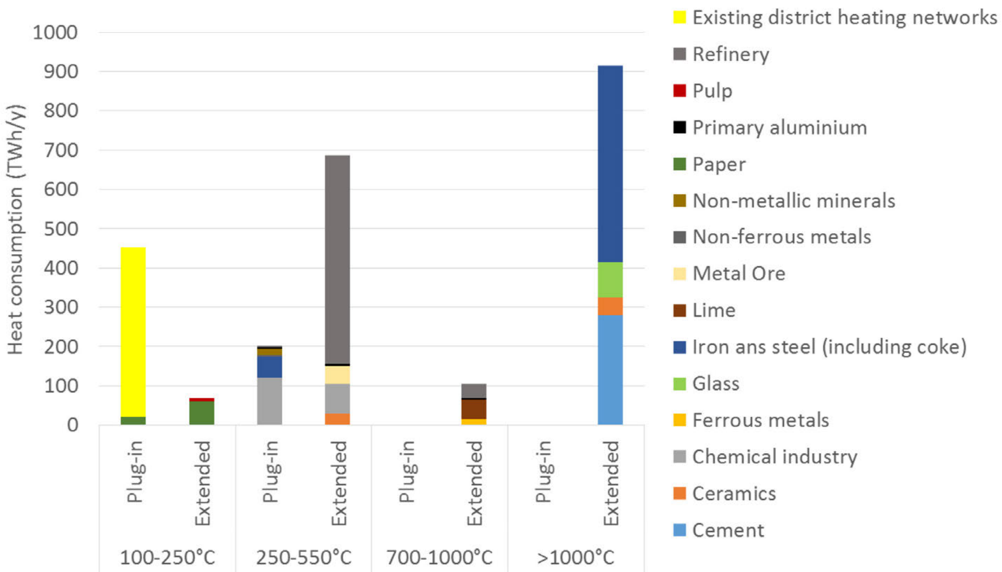
Source: Bredimas (2014) and Bredimas (2011a).

Cogeneration may therefore face difficulties to respond to some specific heat requirements: it is limited by heat transport technologies at very high temperatures. Moreover, nuclear cogeneration can be considered in two different situations: replacing an existing cogeneration plant or replacing an internal burner/boiler when the other constraints (heat transport issues, safety requirements, availability requirements, etc.) can be overcome. Thus, the heat market can be split in two different segments:

- plug-in (which includes existing cogeneration plants and heat production sites where a suitable distribution network is available);
- extended (which includes existing burners or boilers used onsite or even within a process for industrial applications).

Figure 4.6 shows the distribution of the European heat consumption in each industrial market segment. It appears that the market requirements are mainly focused on temperatures below 550°C and on very high temperatures (>1 000°C). Figure 4.6 also shows that the "plug-in" market is restricted to temperatures below 550°C. This is due to heat transport constraints: it is no longer technically possible to transport steam above 550°C and higher-temperature applications use internal burners to produce heat in situ ("extended" market).

Figure 4.6: **European district heating and industrial heat market segments**



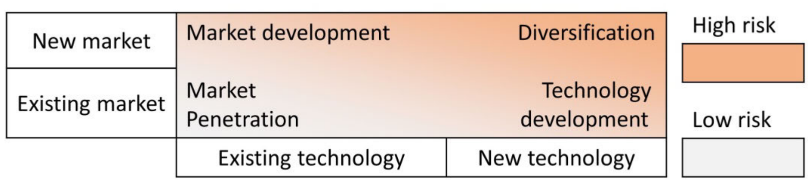
Source: Adapted from Bredimas (2011a) and Bredimas (2011b).

The heat supplied to buildings through district heating networks (430 TWh/year) is represented (Aalborg Universitet et al., 2013). To improve readability, the remaining heat consumption in the buildings sector is not represented, even though it is much higher than any other market segment (approximately 3 300 TWh/year) (Aalborg Universitet et al., 2013).

No information on the consumption of the food and tobacco industry has been included, yet it is supposed to be of order of magnitude as the pulp and paper industry.

Apart from their unequally distributed market shares, these segments also have uneven risk profiles. The risk intensity of innovative projects is usually depicted in the so-called Ansoff Matrix (Figure 4.7). The way this matrix classifies risk shows that existing technologies targeting existing market (market penetration strategy) are less risky projects than new technologies targeting new markets (diversification strategy).

Figure 4.7: **Ansoff Matrix: the risk in innovative projects**



Source: LGI Consulting.

Since they rely on current nuclear reactor technologies, low-temperature applications such as district heating and desalination are probably the less risky cogeneration applications. They either target existing markets (e.g. replacing old fossil fuel-based CHP plants) or new markets (cities which do not yet have a district heating network or countries willing to increase their desalination capacities).

On the other hand, a market also exists for the supply of heat for high-temperature industrial applications and nuclear cogeneration could either target existing markets (e.g. replacing old fossil fuel-based CHP plants) or new markets (replacing burners operated within the industrial facilities). But the reactor technologies are not as mature as current technologies: potential high-temperature applications for nuclear cogeneration are either based on HTR reactors (up to 500°C) or VHTR reactors (applications above 500°C). HTR reactors do not require any new technology but still need a demonstration program. VHTR reactors are still at an early stage in the design process and will require developing new technologies.

Finally, the diversification strategy (new technology and new market) is generally considered too risky, especially in a capital-intensive industry such as nuclear. This risk explains the difficulty for high-temperature nuclear cogeneration application projects following this strategy. To a certain extent, projects for nuclear-based hydrogen production could be considered as diversification projects since neither the technologies (high-temperature electrolysis or thermochemical cycles) nor the go-to-market strategy are fully matured.

4.3. Business models, onsite integration and market size in low-temperature applications

Low-temperature applications of nuclear cogeneration are proven in real industrial environments: several projects in the main three sectors (district heating, desalination, process heat for the paper industry) proved the concept and many have reached the industrial operation stage. Integrated nuclear desalination plants have reached almost 250 reactor-years of experience, mainly acquired in Kazakhstan, India and Japan (Dincer and Zamfirescu, 2014). Much experience has also been accumulated in district heating projects (approximately 500 reactor-years [Dincer and Zamfirescu, 2014], especially in Europe and Russia: the main nuclear district heating systems started to operate in the 1980s (seven operational systems in Russia and seven others across Bulgaria, Hungary, Ukraine, Slovak Republic and Switzerland [IAEA, 1997]). Some of these systems had been demonstrated earlier (in China, Russia and Sweden [IAEA, 1997]). More recently, a nuclear district heating system was built in Romania (IAEA, 2008).

In fact, most ongoing nuclear cogeneration projects deal with desalination or district heating (those for which feasibility studies are ongoing, see examples in Chapters 2 and 6).

The following sections present the possible business models and integration models for these two main applications. Market size estimates are also provided.

District heating

District heating requires relatively low temperature steam or water (around 80°C-150°C), which makes this application suited for any existing reactor type, including LWRs: steam can be extracted from the low-pressure turbine (secondary system) and used to provide heat to a closed heating network through heat exchangers. In fact, most nuclear applications of district heating have been based on LWRs so far. A few experimental projects also demonstrated the technical feasibility of district heating based on fast neutron reactors or high-temperature reactors. A BN-600 prototype reactor started operating and offering district heating in 1981 in Belojarsk (Russia) and the HTR-10 reactor at the Tsinghua University in Beijing has contributed to local heating in winter time.

For several reasons, nuclear plants rarely dedicate full capacity to heat production for housing. On the contrary, the design of present cogeneration plants generally assigns most of the thermal capacity to the power production system and the waste heat of this system is then transferred to a distribution network, possibly adding a small share of the thermal capacity[1].

1. Even though in current DH applications, the heat production capacity rarely exceeds 5% of the overall thermal capacity, some Russian nuclear power plants have proved to be able to produce larger amounts of heat (e.g. the Balakovskaya plant – 12 000 MW_{th} capacity – produces 920 MW of heat in addition to 4 GW_e).

First, this is because residential heat demand is seasonal (the plant may deal with periods with no heat load during the hot season). Keeping electricity production as the main activity helps maximising the overall load factor throughout the year. Second, as mentioned before, transporting heat is costly, which is why nuclear cogeneration plants usually only provide heat to the nearby urban area (typically within a range of 15 km and rarely further than 50 km). This limits the peak heat demand from 10 to 50 MW_{th} for small towns to approximately 600 to 1 200 MW_{th} for large cities. On the other hand, electricity generating nuclear power plants are usually designed based on economy-of-scale considerations, leading to large thermal capacities (e.g. approximately 1 500 MW_{th} for a 500 MW_e unit or 4.5 GW_{th} for a 1.5 GW_e plant). Thus, aside from the case of a small plant providing heat for a large city, the thermal capacities of nuclear power plants are generally higher than the peak heat demand.

The following analysis of business models is built on the previous comments. Yet, some of these assumptions may prove to be wrong in specific circumstances. For instance, there were examples of nuclear reactors providing heat only (research reactors in China and Russia, usually smaller than commercial units). This could also be questioned if small modular reactors become more popular in the future. These would probably allow targeting smaller cities or isolated areas, and specific SMR designs could be suitable for heat-only applications.

Besides, there are specific business conditions which may vary from one project to another. The most important condition is certainly related to existing infrastructures: a nuclear district heating project in which the nuclear power plant already exist may not follow the same business model as a project in which the district heating network pre-exists or a greenfield project (no existing nuclear power plant or network). This reinforces the necessity to analyse possible business models as well as onsite integration and it will influence the economic assessment of the project (Chapter 5).

Business and integration models

Historically, nuclear district heating systems were either part of integrated (see Figure 4.2) or non-integrated energy clusters (see Figure 4.1), and no example of end-user owned systems has been reported so far.

The integrated systems were the norm in Soviet countries. This system matches well with projects in which the district heating network is designed and built at the same time as the nuclear plant (the plant and the distribution network are then jointly funded and owned). This business model may also, however, be suitable in different situations. In France, the integrated business model has recently been considered in pre-feasibility investigations (using the St Alban Nuclear Power Plant to feed the Lyon metropolitan area with heat, cf. Chapter 6, and complementary work in the Paris area [Jasserand and Lavergne, 2016]). In this hypothetical project, based on the current situation, French utility EDF would be the plant owner and Dalkia (EDF's subsidiary) the heat network operator. In this example, both the nuclear power plant and the heat network already exist and only the junction between the two has to be built. Another option mentioned in this study would be to feed the existing network with heat from a new plant if the current Bugey Nuclear Power Plant were to be replaced.

Until now, the non-integrated systems have been more common in Europe, the main historical example being the district heating network of the Beznau Nuclear Power Plant in Switzerland (see Chapter 6). In this case, the heating network was built after the power plant (both Beznau units were commissioned in the late 1970s and the heat network started operations more than a decade later). The plant operator (Axpo) and the heat network operator (Refuna AG) are separate companies: the plant sells the heat to the network operator at a price slightly higher than its opportunity cost and then the network operator sells heat to the customers at a higher price (partly indexed on other commodities such as oil and gas).

Market size

The segment dedicated to buildings in the global heat market is large (84 EJ in 2011, i.e. 23 000 TWh_{th}) and has grown by 1% each year since 2000 (IAEA, 2014). As fossil fuels remain the main source of energy for this market (oil, gas and coal account for more than 50% of heat production), the potential for reducing CO_2 emission in the buildings sector is significant. Besides, the rest of the heat for building is produced by renewable energies (low-carbon or carbon-neutral energies) but some may still cause air pollution issues (solar thermal and geothermal heating only count for a few percent and the rest of renewables includes biogas, biofuels and solid biomass). Although nuclear cogeneration can bring solutions to decarbonise this heat segment and reduce air pollution, it cannot respond to the entire demand for several reasons:

- Not all buildings depend on district heating: rural and sparse urban areas rely on individual heating solutions, incompatible with centralised CHP, whether nuclear or conventional.
- Not all countries have or will conduct a nuclear programme (in 2014, 30 IAEA member states were operating nuclear power plants and the agency identified 33 additional countries either considering, planning or starting nuclear power programmes [IAEA, 2014]). Therefore, only a fraction of all district heating systems may consider nuclear cogeneration as an option to provide heat.

According to a UN report on district energy, the top 45 cities for district heating represent a total of 36 GWth in installed heating capacity and 6 GWth of cooling capacity (UNEP, 2015). Less than ten of these cities are located in countries not considering future nuclear developments (including Germany, Denmark, New Zealand). Even so, this top city market segment still represents approximately 30 GWth (i.e. about one LWR of 1 GWe/3 GWth capacity per city, devoting a third of this capacity to heat production).

Focusing on Europe, more than 2 445 district heating systems in 2 188 cities having more than 5 000 inhabitants, according to Aalborg Universitet et al. (2013). Another report shows that there are 130 large fossil fuel-fired plants located within 110 km from a European city with at least 600 000 inhabitants and these plants are more than 20 years old (Andrews et al, 2012). These plants have capacities larger than 900 MW_e and account for 234 GW_e in total. If the threshold is lowered to plants above 300 MW_e, there are 174 plants (141 GW_e in total) and 101 (78 GW_e in total) of them are 50 km from the city. Although the current policies of some EU member states do not support nuclear development, there are serious opportunities to decarbonise district heating in Europe. Nuclear cogeneration is a low-carbon option to replace the fossil fuel-fired plants and some European countries already operate nuclear cogeneration plants or have established plans to do so (Finland, Switzerland).

Game-changing drivers

Nuclear cogeneration district heating is a proven concept. No technological challenge prevents this concept from winning market share in the buildings sector, but a few key drivers may determine whether the concept will be adopted or not, and how fast.

Building gas-fired power or CHP plants requires little capital investment. On the other hand, operating those plants, which includes the supply of the fuel, makes up most of the heat (or electricity) production cost. High natural gas prices in Europe explains why many gas-powered plants have shut down over the past years.

The price of gas is therefore potentially one of the most important drivers of the transition from gas-fired heat production to a low-CO_2 system. Indeed, a rapid increase in gas prices could force the shutdown of existing gas-fired plants even though they have not reached the end of their life span. Alternative heat production plants may include nuclear cogeneration systems. The influence of gas prices on nuclear cogeneration competitiveness is quantified in the economic analysis of Chapter 5.

It should be stressed that gas prices may not have the same game changing effect in all regions of the world. While in Europe, Japan and China the prices of natural gas have reached some significant highs over the past few years, North America faces a much different situation. In the United States, the shale gas boom of 2008 drove prices down sharply and they have not recovered yet.

Beyond the price, the dependency on gas imports may also play a significant role in the transition to a low-carbon building heating system. This potential driver of change will depend on the specific situation of each country and the political willingness to increase energy independence.

Likewise, the political willingness to cut CO_2 emissions can drive the transition and the efficiency of the corresponding policies will determine how fast that happens. The big difference with the energy security driver is that limiting CO_2 emissions is now expected to be the priority of every country.

Finally, focusing on potential local drivers for nuclear cogeneration, political decisions such as shutting down fossil fuel-fired plants near a city to fight air pollution or funding the construction of a public district heating network would greatly improve the feasibility of nuclear district heating systems and could therefore revitalise a number of dormant projects.

Desalination

There are two types of technologies used for water desalination: thermal processes (multi-stage flash [MSF] and multi-effect distillations [MED] are the most common) and membrane processes (reverse osmosis is the most common). Reverse osmosis only requires electricity while MSF/MED require both heat and electricity, which is why the reverse osmosis market share should not properly be included in the desalination segment of nuclear cogeneration. Besides, thermal processes have a higher global energy consumption according to the World Intellectual Property Organization (WIPO, 2011):

- electrical needs: 3.5 to 5 for MSF vs. 1.5 to 2.5 kWh/m^3 for MED and 2 to 8 kWh/m^3 for reverse osmosis;
- thermal needs: 45 for MSF vs. 28 kWh/m^3 for MED (needs are almost doubled if the plant is "stand alone", i.e. not coupled with a cogeneration plant).

A third type of desalination plant (hybrid) combines both thermal processes and membrane processes, thus also requiring both electricity and heat.

In terms of temperature requirements, nuclear desalination has even slightly lower maximum requirement (no more than 130°C) than district heating. Therefore, all reactor types are suitable for this application.

While experience in nuclear desalination mainly comes from Japan and Kazakhstan, recently commissioned plants are located in India and Pakistan and one plant is still operating in the United States (Diablo Canyon). Japan counts seven nuclear desalination units, and all of them (Takahama-3, Takahama-4, Genkai-3, Genkai-4, Ikata-3, Ohi-3, and Ohi-4) are re-operating after the Fukushima Daiichi accident.

Business and integration models

In earlier nuclear desalination applications, the plants provided make-up water to the nuclear power plant. They may have also occasionally sold excess freshwater production to the public or the nearby municipality. This explains why most nuclear power plants were built at the same time as the desalination plant they were tied to.

On the contrary, in desalination projects being explored in India and Pakistan, the nuclear power plant already exists and has been operating for three decades or more. The desalination plant will then only be plugged in to the existing plant, extracting steam from the secondary system. The purpose of the Indian and Pakistani projects is to demonstrate the feasibility of nuclear desalination.

Thus, in most cases (commercial operations or demonstrators), the desalination plants are owned and operated by the same companies as the nuclear power plant. Therefore, the most common ownership models for nuclear desalination are either build-own-operate or the standalone entity. In the future, the growing demand for fresh water may lead to different business models in which the desalination plants are designed to produce much more than the nuclear power plant requirements, especially if those reactors get smaller (see e.g. the 330 MWth Korean SMART reactor, designed for both electrical and thermal applications like desalination). In this case separate companies could own and operate the desalination facilities.

Market size

Historically, thermal processes dominated the desalination market, especially in the Middle East, where energy costs are low. But over the past 10-20 years the market share of reverse osmosis has grown, and this process now represents more than 50% of total installed capacities (currently around 90 Mm^3/d [GCWDA, 2015]). Yet, thermal processes should maintain a significant market share in the foreseeable future for several reasons:

- They provide better end-products (based on output water quality).
- They remain competitive everywhere energy is cheap (for instance in demand-driver countries like the Middle Eastern Gulf states) or where a waste heat source is available, and.
- Hybrid technologies involving both thermal and membrane processes are emerging to take advantage of lower energy consumption and higher output quality (WIPO, 2011 and Al-Mutaz, 2003).

According to the newly created Global Clean Water Desalination Alliance, global desalination needs and corresponding CO_2 emissions could triple by 2040 under current trends (GCWDA, 2015). To prevent those additional CO_2 emissions, the Alliance (gathering 80 international stakeholders) agreed on common objectives during COP 21 in Paris:

- having 10% of the fuel for existing desalination plants come from clean energy sources by 2030;
- increasing the share of clean energy sources for "new build" plants, from 20% in 2020 to 80% after 2035.

Considering an increase of +90 Mm^3/d in installed capacity (i.e. 90 of the current biggest desalination plants, including the Ras Al-Khair plant in Saudi Arabia) for thermal processes by 2040 (50% of the total increase, the rest going to reverse osmosis applications), low thermal needs (30 kWh/m^3, leaving space for technological improvements) and 50% of clean energy for new builds, nuclear cogeneration could provide the desalination market with 500 TWh per year. Assuming this thermal energy is provided by LWRs[2] devoting a third of their capacity to heat production and assuming their thermal efficiency is 33%, this fleet of 500 MW_e cogeneration reactors would represent approximately 160 units (about 3 units per desalination plant of the same size as Ras Al-Khair).

Game-changing drivers

Like district heating, nuclear desalination is a proven technology being operated today. Therefore, the two applications face no technological challenge and roughly share the same game changing drivers: economics and the political willingness to cut CO_2 emissions and increase energy independency.

These three drivers were decisive in the case of Japan, the leading country for nuclear desalination. In addition to the existing infrastructure (mainly desalination plants producing water for the nuclear power plant they are coupled with), the country is conducting studies for the construction of a high-temperature reactor (the 600 MW_{th} GTHTR300C) to produce electricity (300 MW_e) and fresh water from waste heat. The Japan Atomic Energy Agency has completed the design and the projected water cost would be half that of using gas-fired combined-cycle gas turbine (CCGT) (WNA, 2017).

Yet, desalination has some specificities. First, the desalination market is concentrated in coastal areas with limited access to fresh water. Many of these areas have a dry climate and receive intense solar radiation. Therefore, alternative low-carbon technologies like solar thermal technologies could prove to be competitive against nuclear cogeneration. Besides, in the Middle Eastern Gulf countries, the driver for change would not be the energy costs but more likely to come from political willingness to diversify the energy mix, and/or to reduce CO_2 emissions.

2. We consider 500 MW_e reactors, each producing 3.13 TWh_e/year (which matches the current global capacity/electrical production ratio: 2 500 TWh/400 GW_e) or 3.13 TWh_{th} + 66% * 3.13 TWh_e in cogeneration mode.

To date, the public acceptance of nuclear desalination has not been problematic. In fact, nuclear desalination plants have raised the standard of living and supported industrialisation by providing fresh water for drinking, vegetation and industrial use. Two cases in particular support this conclusion; first the nuclear power plant at Kalpakkam, India, based in a water-scarce region, is experiencing demand growth for its desalinated water. Second, a desalination plant coupled to a BN300 reactor in the desert region of Aktau, Kazakhstan, provided water for the local population and industrial growth (IAEA, 2019). Thus, nuclear desalination is a good candidate for improving public acceptance of nuclear cogeneration.

Finally, even though nuclear desalination systems are proven concepts, some technological improvements could be game changing drivers. Indeed, the MED technology operates at much lower temperatures (60-70°C) than MSF, the most common thermal process which requires hot water at 90-100°C or more. The efficiency of the MED process has improved constantly. If the technical improvements allow the operating temperature to keep decreasing to 50-60°C, 100% of the waste heat of LWRs could be used with no impact on electricity production at all and this would significantly impact the economics of desalination (Dardour and Safa, 2017).

Other industrial applications

Apart from desalination, other industrial sectors may benefit from nuclear cogeneration: pulp, paper, food and tobacco industries. Yet, the overall heat requirements of these industrial sectors are currently limited compared with the heat requirements for buildings, desalination and high-temperature requirements for industry (cf. next section). Therefore, no detailed analysis is conducted for these applications.

Since 1980, a few nuclear plants have provided process heat for industrial applications (e.g. D_20 production in Canada and India, salt refining in Germany, cardboard production in Switzerland [IAEA, 2008]).

Some of these applications require higher temperatures than district heating and desalination and use pressurised steam up to 250°C which, under specific circumstances, is still compatible with current nuclear reactor technologies.

The Indian and the Canadian experiences are based on CANDU reactors (heavy water moderated reactors) and the heat is used to produce heavy water (D_2O). The business model is close to the "End-user owned energy cluster" depicted in Figure 4.3 with a certain level of integration (e.g. in Canada, Ontario Hydro owned and operated both the nuclear power plant and the D_2O production plant).

On the other hand, the Swiss and the German experiences are based on PWR reactors (light water moderated reactors) and the heat is used by factories (cardboard, salt refinery) located a few kilometres from the plant area.

There have been limited uses of nuclear steam for other process industries. In Canada, Bruce A power plants, in addition to a steady supply for heavy water plants, also provided 72 MWth of medium pressure steam to the Bruce Energy Centre industrial park housing a plastic film manufacturer, a greenhouse, an ethanol plant, and an agricultural research facility (IAEA, 2017). In Switzerland, the Gösgen nuclear plant supplies 45 MWth medium pressure steam (~1% of the total output) to a cardboard factory (IAEA, 2017).

Diversion of high-quality steam for industrial applications comes at the expense of reduced electrical output and therefore economics plays a major role in such applications.

4.4. Business models, onsite integration and market size in high-temperature applications

The main difference between low-temperature (below 250°C) and high-temperature applications (above 250°C) is that current nuclear reactor technologies are not suitable with high-temperature applications. Several reactor technologies are suitable to address higher-temperature applications, including HTGRs or very high temperature reactors (VHTR). HTGR reactors are probably the most mature designs among them and yet only count two experimental units in operation (the high-temperature test reactor [HTTR] in Japan and the HTR-10 in China) and two first-of-a-kind (FOAK) units under construction (the HTR-PM in China). In the past, several other experimental and industrial prototypes have been operated, but none were used for cogeneration.

In that respect, the industrial viability of high-temperature nuclear cogeneration still needs to be demonstrated, but the following analysis of possible business models and potential markets shows the outlook is promising. A specific section is dedicated to hydrogen production since, unlike the product of other industrial applications, hydrogen can be considered both an end-product and an energy carrier.

Industrial applications

The industrial sector's demand for heat comes from various applications and represents almost half of total final use heat demand (building heating representing the other half). Those requiring high temperatures represent a significant market share and cover a broad range of temperatures as shown in Figures 4.5 and 4.6.

Among industrial applications, Figure 4.6 shows that higher-temperature segments have a slightly higher market shares (except for the 550-1 000°C range for which very few applications are optimised as mentioned in Section 4.2). They also show that in all temperature ranges[3], the "plug-in" heat market share (i.e. substitution of an existing fleet of cogeneration plants by feeding existing infrastructures for steam distribution) is smaller than the "extended market" (when heat is provided by boilers and burners operated within industrial facilities and/or directly embedded into the processes).

Apart from iron, steel, cement and glass making, most industrial processes require heat at temperatures around or below 550°C (Figure 4.6). This fits the output temperature of HTGR reactors. In that respect, an EU-funded research programme pointed out that the chemical industry could offer good opportunities to implement nuclear cogeneration in the near term, since temperature ranges are compatible and so are the power capacity of HTRs and the size of some large chemical parks (Ståhl and Auriault, 2015). Part of the high-temperature applications already uses cogeneration. Moving to nuclear cogeneration could help decrease CO_2 emissions and could be of strategic interest to reduce fossil fuel imports and the volatility of input energy costs.

Business and integration models

Since there is no experience in high-temperature nuclear cogeneration (> 250°C), there is no dominant business model. Therefore, devising innovative solutions (in funding, business modelling, on-site integration, etc.) is necessary. As indicated by the European research programme, solutions may be drawn from the chemical industry since conventional cogeneration has been used in this sector for a long time. In the chemical industry, ongoing cogeneration projects demonstrate that several business models can be implemented: integrated/non-integrated energy clusters and less frequently energy clusters in which the chemical company owns or partly owns the cogeneration plant.

In fact, the prevailing trend towards energy management systems (integrated or not) in which chemical companies are not involved shows that these heat end users prefer to focus on their core business. Indeed, it seems that the chemical industry tends not to get too involved in energy management (ownership, operation and power distribution) and prefers long-term contracts to source its energy requirements. This strategy is efficient to hedge against volatile energy prices.

It is unclear if this trend would hold for nuclear cogeneration plants feeding chemical parks. On the one hand, they may prefer to remain simple heat end users and not to participate in nuclear cogeneration plant funding or ownership since the high capital intensity could be perceived as a risk to their core business. On the other hand, nuclear is better than any fossil

3. The low-temperature range (100-250°C) is misleading since the "plug-in" market of the buildings sector was added to the picture.

fuel at hedging against energy price volatility, which would be a reason for chemical companies to support and invest in nuclear cogeneration projects within their clusters. Besides, specific ownership models like Mankala companies (cf. dedicated paragraph in Section 4.1) may help mitigate the financial risk, while splitting the investment between various stakeholders and developing SMRs may reduce the capital intensity.

Similar questions arise for the other industrial applications, each of them having their specificities. For instance, applications like steelmaking, in which the process heat is provided on location by burning fuels, are currently compelled to have an integrated energy management system. Even though heat production on location is beyond the reach of current nuclear cogeneration solutions (too high temperature, heat transport issues, etc.), nuclear pre-heating solutions could contribute to decreasing fossil fuel dependency. This would certainly be a driver of change for the business model of energy management within the industrial clusters of those applications: nuclear pre-heating would partly externalise the energy management.

Market size

- Plug-in market

Considering the sectors for which HTGR reactors would be suitable (all industrial applications up to 500°C), the global heat demand is approximately 30 EJ/year (IAEA, 2014) (i.e. 8 300 TWh, as applications reported as "unspecified" in the report were discarded), mainly fuelled by oil, gas and coal up to now. European demand is approximately 900 000 GWh/year (Bredimas, 2014) (applications in the range 100-250°C were excluded as they mostly refer to district heating, which was addressed previously), of which 200 000 GWh are delivered by "plug-in" installations. According to Figure 4.6, the chemical industry is the main sub-segment in the "plug-in" market.

Assuming that nuclear energy could target a 50% penetration rate in the whole "plug-in market", this would represent 23 reactors units (500 MW_{th} units available for 8 000 h/year and 10% losses) in Europe and 933 units worldwide. It should be noted that the reactor size is a key parameter in the market size assessment since smaller plants can target more clients (small industrial clusters).

- Potential triggering factors

While the long-term penetration rate of HTGR reactors can be discussed, this market size estimate does not consider economic issues. Among all the potential units, HTGR reactors may become competitive in some cases depending on various parameters, the main drivers being the size of plants for each industrial application, the cost of fossil fuels, and the carbon tax policies.

According to Demick (2011), the Idaho National Laboratory conducted an analysis to determine the market in the United States for which HTGRs could be an economical alternative (under certain assumptions on capital and operating costs, as well as on costs for carbon emissions). The report finds that with the natural gas prices of the time in the United States, HTGRs could be competitive for industrial plants or clusters requiring 900 MW_{th} or more (even without a price on carbon), and for those between 600 MW_{th} and 900 MW_{th} with a price on carbon. In the United States, 105 cogeneration plants are rated above 900 MW_{th}, representing total capacity of 156 GW_{th}. Replacing half of them with a nuclear plant would represent a market of about 75 GW_{th}, or 125 units of 600 MW_{th} capacity. Of course, the size of industrial clusters may change from one region to another and this estimation may not stand outside the United States.

In any application, the development of SMRs may be a game changer. Currently, modern HTGRs are all SMRs. The capital intensity of small reactors would be lower and end users might be less reluctant to be involved in financing. The market size covered by these reactors would also be larger (targeting smaller industrial plants).

Finally, some of the drivers (energy prices, energy policies) considered as possible game changers for low-temperature applications could also trigger some project realisations in high-temperature applications. Climate change policies, particularly high carbon taxes, would also be a driver for future cogeneration opportunities. For instance, Poland appears to be an excellent country for the demonstration of a European high-temperature reactor providing heat and electricity: the industry is mainly fuelled by coal and gas and the country has concerns about its energy supply security. Besides, Poland hosts a significant number of industrial clusters in which the chemical industry is widely represented.

Extended markets

As pointed out by European Union-funded research (Bredimas, 2014 and 2011a), the extended heat market is more difficult to penetrate than the plug-in market. This is due to technical challenges which may either depreciate the economics of nuclear cogeneration (major investments to adapt the existing process or infrastructure to an external source of heat) or compromise the project feasibility. In the long term, the extended market at very high temperature could be addressed by VHTR reactors but no commercial reactor is expected before the second half of the century and technical solutions would be required for heat transport. Before that, HTGR reactors could be used to provide pre-heat.

As mentioned before, using nuclear cogeneration for pre-heating is a way to provide a technically feasible solution to any industrial application, whatever the temperature of the process. Still, it is uncertain what part of the total heat requirement could be addressed by pre-heating. In the short and medium terms, there are reasons to believe that nuclear cogeneration for pre-heating purposes will not be significant. In very-high temperature applications, the exhaust gases of the plants are usually hot enough to be utilised if adjacent industrial processes require pre-heating. Indeed, the current trend in research programmes for energy-intensive industries seeks to develop energy efficiency solutions at the process level or to look for synergies within their industrial clusters, rather than developing pre-heat production systems.[4]

Hydrogen

Hydrogen is a common element that does not exist on its own in the environment but is found in water (H_2O) and associated with carbon in organic matters. This means energy is required to separate hydrogen from oxygen or carbon. In addition, hydrogen can play a versatile role as an energy carrier and for a range of industrial processes. On the one hand, hydrogen can be considered an industrial gas and used in industrial processes for its chemical properties (this is currently the main application), or it can be considered a pure energy carrier, including for long-term storage. Over the last decade, a renewed interest for hydrogen as a pure energy carrier and a potential substitute to fossil fuels (in particular in the transport sector) has opened prospects for accelerating the transition to a low-carbon economy. The idea of a *hydrogen economy,* originally described by Jeremy Rifkin (Rifkin, 2003), has grown together with R&D programmes on new ways of producing hydrogen with limited CO_2 emissions and new ways of using this hydrogen.

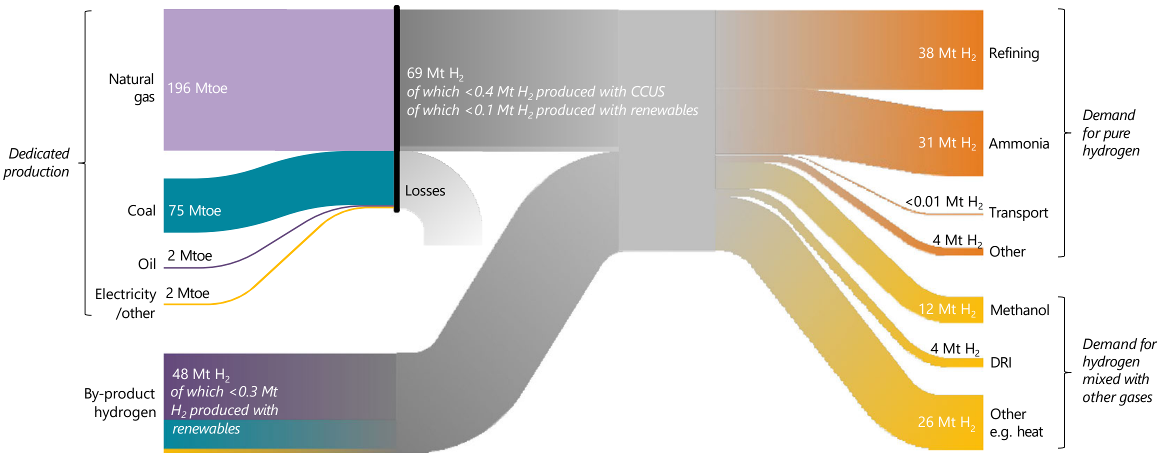
Currently, global dedicated hydrogen production is approximately of 70 million metric tons per year while by-product hydrogen production is approximately 50 million metric tons per year. Refineries with 38 Mt per year are the first single source of hydrogen consumption, heeled by the chemical industry for ammonia and methanol production, which consume respectively 31 and 12 Mt of hydrogen per year (ammonia is mostly used in the production of fertilisers). The remaining share, around 25% of total production, is spread across smaller applications like steel making, heat, transport, and chemicals (IEA, 2019).

In the future, hydrogen as an energy carrier could be widely used in fuel cells or gas turbines to produce electricity. It could be mixed with natural gas or used for manufacturing synthetic hydrocarbon fuels from coal or biomass. If the *hydrogen economy* takes off at least partially, these new uses of hydrogen are expected to grow at an increasing rate. For instance, in the Net Zero scenario from the International Energy Agency, it is expected that hydrogen-based fuels will provide 28% of the transport sector's total final energy consumption by 2050 (IEA, 2021). Most of the potential new applications of hydrogen are being explored through demonstration programmes at various scales.

4. Furthermore, new business models emerge for valorising waste heat from industrial processes, for instance based on Organic Rankine Cycle power generators.

Hydrogen production from hydrocarbons or from water (water-splitting processes) are the most discussed options. Today, approximately 95% of the hydrogen produced worldwide comes from hydrocarbons and involves CO_2-intensive processes. Three-quarter of this hydrogen is obtained from natural gas primarily through the steam methane reforming process and which is therefore the most developed industrial solution to produce hydrogen.

Figure 4.8: **Today's hydrogen value chain**



Source: IEA, 2019.

To obtain hydrogen from water with low CO_2 emissions, the only mature industrial solution is low-temperature electrolysis. Today, this process is not competitive with steam methane reforming, except in very specific situations where low electricity prices and high electrolyser's load factors meet high gas and CO_2 prices. Otherwise, low-temperature electrolysis could cost at least twice as much as steam methane reforming (IEA, 2019).

Alternative water-splitting processes (high-temperature electrolysis and thermochemical cycles) are under development. They offer greater efficiencies but hydrogen production costs remain higher than steam methane reforming because of the higher stress on materials due to the high operating temperatures.

Several production pathways are usually considered to reduce the CO_2 emissions associated with hydrogen production. Using nuclear power is one of them, with several technological tracks considered:

- **Production of low-carbon hydrogen through low-temperature electrolysis:** this is the main short-term industrial solution based on nuclear power to produce hydrogen. However, it does not fully take advantage of the thermal capacity of nuclear power reactors as this is not a cogeneration application.
- **Production of low-carbon heat and electricity for high-temperature electrolysis or thermochemical cycles:** HTGRs could provide the necessary heat to the hydrogen production process and ensure a high overall efficiency. Significant efforts are ongoing to improve the technological and industry maturity of the process. In the short term, several initiatives aim to demonstrate how LWRs coupled with electrical topping heaters can enable large-scale hydrogen production from high-temperature electrolysis (Nice Future, 2020).
- **Pre-heating solution for steam methane reforming**: this process requires high-temperature heat and nuclear cogeneration could help reduce the actual CO_2 balance of the process. However, as discussed in the previous section, the outlook for pre-heating cogeneration applications is highly uncertain as this is the least mature technological solution.

Business and integration models

Hydrogen production is compatible with the ownership and site-integration models described in Section 4.1. However, the rest of the energy manager's business model may differ since having a hydrogen production facility in a cluster may allow energy storage and an optimisation between heat, power and hydrogen production based on market conditions. An example of this approach is the polygeneration concept (Bredimas, 2011a) explored in detail in different studies from the Idaho National Laboratory (INL).

In addition, as new technologies for producing and using hydrogen could take off during the 21st century, a broad range of possible business models for hydrogen producers with different impacts on nuclear cogeneration can be considered.

Currently, only a part of hydrogen production is engaged for commercial reasons, e.g. as dedicated hydrogen production. A significant part of hydrogen is produced and used by the same company, such as by-product hydrogen (mainly used by refineries). Even when hydrogen is sold commercially, it is still usually consumed within the industrial cluster where it was produced. For hydrogen to become widely used as an energy carrier, a transport and distribution network would need to be established, and the business models of hydrogen producers would be transformed. Many models and combinations of technologies are usually considered for the production-distribution-use value chain of hydrogen. The main parameters influencing possible business models are the hydrogen plant's size and a connection to a hydrogen transmission network. In the short- to medium-term time horizons, the principal business models are:

- **Centralised production**: Hydrogen is produced in large quantities, possibly spread out through a dedicated network to the customers (industrial clusters, fuelling stations, etc.).
- **Distributed production**: Hydrogen is produced, stored and used on site. In part, this could be considered a captive hydrogen market.

These business models largely influence the cost structure of hydrogen production and distribution and they also impact the overall energy efficiency (Table 4.5). For instance, it is worth noting that centralised steam methane reforming production has a higher overall cost (including distribution costs) than distributed steam methane reforming production and a lower overall efficiency. It is also worth noting that a distributed hydrogen production based on low-temperature electrolysis from nuclear power or renewables is almost competitive with the centralised steam methane reforming production while offering much lower CO_2 emissions.

Table 4.5: **Default production costs, distribution costs, conversion efficiency, and GHG emissions**

Pathway	Production cost (excluding feedstock) USD/GJ (USD/kg)	Distribution cost USD/GJ (USD/kg)	Feedstock conversion efficiency (MJ H_2/MJ feedstock)	Well-to-tank GHG emissions (kg CO_2e/kg H_2)
Natural gas: distributed steam methane reforming	6.67 (0.80)	13.75 (1.65)	71.9%	14.3
Natural gas: centralised steam methane reforming	3.25 (0.39)	21.50 (2.58)	53.6%	14.7
Coal: centralised gasification	10.75 (1.29)	21.50 (2.58)	53.6%	44.7
Coal: centralised gasification with carbon capture and storage	14.67 (1.76)	21.50 (2.58)	53.6%	7.5
Biomass: centralised gasification	8.92 (1.07)	21.50 (2.58)	49.6%	3.1
Electrolyser options (wind, solar, nuclear)	5.25	21.50 (2.58)	72.5%	2.9

Source: Adapted from Drennen and Schoenung (2014).

This summary table omits the potential solutions brought by nuclear cogeneration (high-temperature electrolysis or thermochemical cycles). These nuclear cogeneration systems could bring innovative business models. In the distributed category, they could provide exclusive tri-generation services within industrial clusters by providing electricity, heat and industrial gases (hydrogen and oxygen).

Market size

The literature provides multiple scenarios on the future demand of hydrogen and usually refers to two time horizons, 2030 and 2050. These horizons reflect uncertainties associated with the two principal factors that will be influencing the hydrogen market's size in the long term:

- the scale of variable renewable integration in future energy systems; and
- the progress on research, development and demonstration on key hydrogen technologies such as electrolysers and fuel cells.

The first point is increasingly part of scenarios looking at decarbonisation pathways. For instance, the European Joint Research Centre (JRC) discusses scenarios for achieving the European greenhouse gas emissions reduction targets for 2030 and 2050. The study concludes that hydrogen production is directly related to the expected electricity generation from variable sources in the long term (Tsiropoulos et al., 2020). In other words, hydrogen is seen as a key tool to answer the future system's flexibility needs.

At the same time, low-carbon hydrogen-based technologies remain far from competitive (IEA, 2019). In this context, market signals coupled with regulatory support appear unlikely to suffice to bring them to required levels of maturity. Therefore, advances in research, design and development (RD&D) in the 2020s will determine the ramp-up of the hydrogen economy from 2030 onward (EC, 2021).

Scenarios show European hydrogen production varying from 500 to more than 2 700 TWh (between 9 and 50 Mt) as the wind and solar electricity volume surges from 2 000 to 8 000 TWh (Tsiropoulos et al., 2020). Similarly, the Department of Energy's latest Hydrogen Program Plan considers low and high hydrogen scenarios between respectively 20 and 60 Mt (DOE, 2020). Those two reports shed light on the uncertainties in hydrogen market sizes by 2050.

According to the US Department of Energy (DOE), the transport sector is expected to be the single biggest source of demand for hydrogen by 2050, from being negligible today. The rest of demand would be split between synthetic fuel and ammonia production as well as oil and metals refining. A comparable market structure for hydrogen can be found in the IEA's Net Zero scenario (IEA, 2021). Dedicated worldwide hydrogen production is estimated to reach 530 Mt, of which approximately 202 Mt (38%) is used for the transport sector, 150 Mt (28%) for industrial applications, 100 Mt (19%) for electricity generation, and most of the rest blended in the gas grid.

For scenarios extending to 2030, the literature converges on a two-pronged strategy that focuses on decarbonising the current hydrogen consumption, primarily from industry, and on investing in RD&D for future hydrogen applications. Market estimations, however, differ between scenarios that see the role of hydrogen limited to hard-to-abate sectors (RTE, 2020) and those that see it as a key energy carrier for future energy systems (IEA, 2019).

Because of low value chain efficiencies, part of the literature maintains that hydrogen cannot rival with direct electrification (Agora, 2021). Hydrogen deployment should therefore focus on sectors where direct electrification is not possible or profitable. In the short term, this mostly concerns the petrochemical and heavy transport sectors. In the longer term, hydrogen will likely be used for producing E-fuels used in ships and planes. Hydrogen could also be considered for light-vehicle transport, residential heating and power generation but in isolated and insulated areas where direct electrification from the grid is harder. Based on the Net Zero scenario, this would represent a global hydrogen market of between 113 and 260 Mt for dedicated production respectively in 2030 and 2050. Otherwise, if hydrogen is to be used as a widespread energy vector in the transport, power and heat sectors, the global hydrogen market could range between 211 and 530 Mt.

One area of convergence in the literature relates to two challenges brought by the production of low-carbon hydrogen at such scales: the need for vast amounts of electricity and the need to ramp up electrolyser manufacturing (IEA, 2021).

For example, assuming an average consumption of 55 kWh per kg of hydrogen for water electrolysis by 2030, producing 100 or 200 Mt of hydrogen would represent new demand of between 5 500 and 11 000 TWh. Steam methane reforming is expected to remain the cheapest and leading technology to produce hydrogen. The scale at which steam methane reforming will contribute to hydrogen production in the future primarily depends on two parameters: the carbon price and the competitiveness of carbon capture, utilisation and storage (CCUS) technologies. For example, the IEA expects that 70% of the dedicated hydrogen will be low-carbon by 2030, half from steam methane reforming with CCUS and half from water electrolysis. Ultimately, this would lead to a new worldwide demand of electricity between 2 000 and 4 000 TWh, or 66% and 133% of Europe's 2019 total gross electricity production. This electricity would power 325 to 1 520 GW of electrolysers, with average load factors closer to 30% or 70%. Indeed, the literature showed that the lowest hydrogen costs are reached with electrolysers operating between 2 500 and 6 000 hours per year (RTE, 2020; IEA, 2019). For comparison, as of 2020, 350 MW worth of electrolysers are operational worldwide. As a result, a growing share of the literature recognises the potential role of nuclear power in meeting future hydrogen demand, as long as nuclear production costs remain competitive (Appert et al., 2021).

Nuclear-renewable hybrid energy systems

Nuclear-renewable hybrid energy systems (NRHES) aim to allow the integration of nuclear with renewable resources so that the optimised integrated system meets the electrical power requirements of the grid while ensuring the economic viability of the entire system. The tightly coupled NRHES (refer to Section 2.3) consists of various subsystems linked together to generate dispatchable electricity and produce at least one industrial product from two or more energy resources. The NRHES could include a nuclear reactor, power generation unit, windmills, solar photovoltaics (PV), thermal and electrical storage, and an industrial process.

Because NRHESs are designed to produce different products based on the value of those products in markets, their optimal designs and operations can be complex. There have been several analyses done on optimisation of the system to maximise overall profit. Such economic analyses focused on identifying the optimal configuration and hours of operation for an NRHES within ranges of price profiles for electricity and industrial product (Ruth et al., 2019). The objective of the analyses was to identify the sizes of the subsystems and the internal energy dispatch strategy that are most profitable under a variety of electricity and industrial product prices. The analyses show that a NRHESs can be economically attractive in situations with volatile electricity prices. They are particularly more economically attractive if the industrial process uses more nuclear thermal energy and less electricity and can be turned off and on easily. Such analyses assume that the NRHES system is operated as an integrated energy cluster model described in Section 4.1. The NRHES capital costs far exceed those of subsystems such as a nuclear plant, industrial process, or wind or solar PV farms. Therefore, creative business models would be required for NRHESs to enable large investments and set up a business structure that would ensure internal energy dispatch decisions are made to maximise profits for the entire NRHES and not individual subsystems.

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Chapter 5. Economic models

This chapter aims to present various possible cost allocation methods when dealing with cogeneration of heat and power. It does not pretend to be an exhaustive review of literature: there are many economic developments on co-products and by-products and this chapter focuses on economic models for the combined production of heat and electricity. The main purpose is to show that some economic methods suit specific cogeneration applications better than others depending on their business models and the project characteristics. From there, the reader gets the first hints on how to conduct the economic feasibility study for a specific nuclear cogeneration application. This is also why there is a progression within this chapter from theoretical cost allocation methods (Section 5.1) to actual implementations of economic assessment methods (Sections 5.2 and 5.3). In the first place, the basis of economic analysis (i.e. not specific to any cogeneration application) is presented and implemented with a high-temperature gas-cooled reactor (HTGR) (Section 5.2). Then, to give insight into more advanced economic analysis (covering specific cogeneration applications), a review of specific analytical tools is conducted and references to actual implementations are introduced (Section 5.3).

5.1. Cost allocation methods

5.1.1. *Concepts of levelised costs and joint costs*

The Economic Modelling Working Group (EMWG) of the Generation IV International Forum (GIF) has published guidelines to estimate the cost of electricity of nuclear reactors (GIF, 2007). They refer to the calculation of a levelised cost of electricity (LCOE), according to:

$$LCOE = \frac{\sum_{t=t_0-T_1}^{t=t_0+L+T_2}[(I_t + FUEL_t + O\&M_t) \times (1+r)^{-t}]}{\sum_{t=t_0-T_1}^{t=t_0+L+T_2}[E_t \times (1+r)^{-t}]}$$

Where:

It	=	Annual capital expenditures in the period t
FUELt	=	Annual fuel expenditures in the period t
O&Mt	=	Annual O&M expenditures in the period t
Et	=	Annual electricity production in the period t
r	=	Discount rate
t0	=	Reference date (generally commissioning date)
L	=	Reactor lifetime
T2	=	Maximum value of lag time (in back-end)
T1	=	Maximum value of lead time (in front-end)

This method is convenient to estimate the production cost of a single-purpose unit (nuclear reactor producing electricity only). It could also be applied to the estimation of the levelised cost of heat (LCONE) or the levelised cost of any non-electrical product (heat, desalinated water, hydrogen, etc.) if the nuclear plant produces this non-electrical product only: E_t would simply be replaced by P_t (annual production of the non-electrical product) in the previous formula.

Yet, there is no straightforward way to apply this method to a dual-purpose plant (nuclear cogeneration reactor producing both electricity and a non-electrical product). In this situation, producing the non-electrical product and producing electricity require joint resources and therefore a specific method is necessary to allocate joint costs.

Some costs are specific to the production of non-electrical products (e.g. steam extractor for heat production or desalination plant) or to the production of electricity (e.g. power generator or power transformer) and therefore can easily be allocated to one activity or the other. But joint costs need to be estimated together before being allocated. In the case of nuclear cogeneration, they mainly include the construction of the nuclear power plant and its main components (infrastructure, steam generator, reactor vessel, etc.), the fuel costs and O&M costs. These joint costs represent all expenses necessary to produce thermal power (steam output from the steam generator of the nuclear plant).

Considering only joint costs in the previous formula makes it possible to introduce a levelised cost of thermal power (LCOT). Based on this definition of joint costs and application-specific costs, there are two ways of deriving LCOE and LCONE in the case of a cogeneration plant.

First, the cost of electricity and the cost of the non-electrical product can be derived using a prorating method:

$$\begin{aligned} \text{LCOE} &= (f \times \text{Th} \times \text{LCOT} + C_E) / E \\ \text{LCONE} &= ((1-f) \times \text{Th} \times \text{LCOT} + C_{NE}) / P \end{aligned} \qquad \text{Eq. 1}$$

Where:

- Th is the annual production of thermal energy;
- E is the annual production of electricity;
- P is the annual production of non-electrical product[1];
- C_E is the electricity-specific costs;
- C_{NE} is the costs specific to the non-electrical product;
- f represents the fraction of thermal energy allocated to electricity;
- LCOT is the levelised cost of thermal energy.

In this sort of allocation method, *f* determines the share of joint costs to be distributed to each application. Three prorating methods are usually considered (IAEA, 1997):

- proportional value method;
- calorific method;
- exergetic method.

Otherwise, the cost of electricity and the cost of the non-electrical product can be established based on a credit method. Rather than adding application-specific cost to a fraction of joint costs, this sort of allocation method sets an arbitrary value or cost for one product. The other product is charged for all costs and then given a credit based on the value of the first product. Three types of credit methods are usually considered (IAEA, 1997 and 2000):

- power credit method (& market-based variant);
- non-electrical product credit method (& market-based variant);
- marginal cost credit method.

1. The unit of P can either be kWh if it refers to heat or m^3 if it refers to water, or metric tons for hydrogen.

Finally, in some cases, the opportunity cost of one product (usually the non-electrical product) is used instead of a levelised cost. This method greatly depends on market conditions (since the opportunity cost of the non-electrical production derives from the market price of electricity) and is not, strictly speaking, an allocation method since joint costs are not estimated first.

Because in nuclear cogeneration joint costs will usually be dominant over application-specific costs, the way joint costs are allocated is important and could influence the estimation of LCOE and LCONE.

5.1.2. *Credit cost allocation methods*

Power credit method

The first method to allocate joint costs is called the power credit method. This is the default method recommended by GIF (2007).

In this method, the cost of the non-electrical product is obtained after subtracting a fraction of the production cost of an imaginary single-purpose plant (electricity only) from the overall expenses of the dual-purpose plant. This fraction is the ratio between the power production of the dual-purpose plant and that of the single-purpose plant (E_2 / E_1 with $E_2 < E_1$).

The cost of the single-purpose plat is: $LCOE_1 = (Th \times LCOT + C_E) / E_1$

The total expenses of the dual-purpose plant are: $Th \times LCOT + C_E + C_{NE}$

Thus,

$$
\begin{aligned}
LCONE = [Th \times LCOT + C_E + C_{NE} - E_2 \times LCOE_1]/P \\
= \left[Th \times LCOT + C_E + C_{NE} - \frac{E_2}{E_1} \times (Th \times LCOT + C_E)\right]/P \\
= \left(1 - \frac{E_2}{E_1}\right) \times (Th \times LCOT + C_E)/P + C_{NE}/P
\end{aligned}
$$

Non-electrical product credit method

The same method could be applied the other way around (non-electrical product credit method), charging electricity for all costs and then crediting the sealable non-electrical product based on the cost of an imaginary plant producing this product only.

A variant of this method proposes to use the market value of the non-electrical product instead of its levelised cost. Thus, the levelised cost of electricity is a function of joint costs and of the price of the non-electrical product (p_{NE}):

$$LCOE = [Th \times LCOT + C_{NE} + C_E - E_2 \times p_{NE}]/E = f(LCOT, p_{NE})$$

Until now, power production has remained the dominant application in most nuclear cogeneration plants, which is why the power credit method is used more often than this method.

Marginal cost credit method

This method follows the same philosophy as the power credit method but instead of considering a single-purpose plant producing more electricity with the same thermal power capacity as the dual-purpose plant, it considers an imaginary plant with exactly the same power output. The thermal capacity of the dual-purpose plant (Th_2) is then higher than the thermal capacity of the single-purpose plant (Th_1) which, in the end, tends to derive lower costs for the non-electrical product than the power credit method. This is due to economies of scale. It has only been used a few times in past feasibility studies for desalination applications (IAEA, 2000).

5.1.3. *Prorating cost allocation methods*

These three methods use Eq. 1 or even a simplified version of it if application-specific costs can be overlooked. Each method derives f in a different way. It should be noted that these methods can easily be extended to tri-generation applications (production of three products: electricity, heat and industrial gas like hydrogen).

Proportional value method

In this method, one possibility is to estimate the market value of each product: V_E for electricity and V_{NE} for the non-electrical product. Then, the fraction of joint cost for each product is derived as:

$$f = \frac{V_E}{V_E + V_{NE}} \text{ and } 1 - f = \frac{V_{NE}}{V_E + V_{NE}}$$

This way of deriving f is convenient in two situations. First, for accounting purposes when the cogeneration plant is already running and delivering both products under fixed price contracts. Second, during feasibility studies, it can be useful if the commissioning of the cogeneration plant does not modify the price of each product. This could be the case if the cogeneration plant replaces another one but proves to be untrue in most other cases, especially if the plant creates its own market for the non-electrical product.

Another possibility to apply this method is to derive f from the levelised costs ($LCOE_1$ and $LCONE_1$) of two separate single-purpose plants, together producing the same amount of product as the cogeneration plant. Thus, the fraction of joint cost for each product is derived as:

$$f = \frac{E_1 \times LCOE_1}{E_1 \times LCOE_1 + P_1 \times LCONE_1} \text{ and } 1 - f = \frac{P_1 \times LCONE_1}{E_1 \times LCOE_1 + P_1 \times LCONE_1}$$

Calorific method

This method refers to the first law of thermodynamics. Whatever their form, all cogeneration products make use of the thermal energy delivered by the plant. Most combined heat and power (CHP) plants produce steam to deliver this energy[2]. The energy embodied in the steam is called enthalpy and is transferred to specific applications (power generator, desalination process, etc.) either by a drop of pressure (through a turbine) or by a drop of temperature (through a heat exchanger). In the calorific method, the enthalpy transferred to each application (h_1, h_2) is quantified and used to derive f. Thus, the fraction of joint costs for each product is derived as:

$$f = \frac{h_1}{h_1 + h_2} \text{ and } 1 - f = \frac{h_2}{h_1 + h_2}$$

Compared with previous methods, the caloric method has the advantage of using the energy inputs of each cogeneration application to allocate costs rather than their outputs (quantity of products or their economic value). An easy way to realise how this can be important is to consider a very inefficient application (high energy input and low product output): the caloric method would charge this application with a high unit cost, demonstrating its poor economic performance, while the other methods would give this application a low cost. One could also consider the case of a non-electrical application facing adverse market conditions (high price of electricity and low price for the non-electrical product): any method based on market value would give a low cost to the non-electrical application and hide its poor economic performance. On the contrary, the caloric method would explicitly point at this poor performance, hence prompting the decision maker to focus on power production until the market conditions improve.

2. Some nuclear power plants use a different heat-transfer fluid but the thermodynamic mechanisms are similar.

Nevertheless, this method can be difficult to apply in pre-feasibility studies if the detailed design of the components of each application is not completed. Yet, if considered cogeneration applications deliver energy products (e.g. electricity production and district heating), then the enthalpies can be approximated by computing backward the thermal energy requirement of each application (from their expected efficiency and their expected energy output).

Exergetic method

This method refers to the first and second law of thermodynamics. In thermodynamics, the exergy of a system corresponds to the maximum useful work recoverable during a transformation and it can only decrease. The exergy of a system is its potential to cause a change as it achieves equilibrium with its environment.

A detailed analysis is necessary to introduce how the allocation factor *f* is computed in this method. This report will only discuss the general philosophy of the method and refers the reader interested in implementing this method to analytical documents (IAEA, 1997), (Ye, 2003), (Nisan and Dardour, 2007).

The main philosophy behind the exergetic method is to take into account the environment of the cogeneration applications to quantify their performance: if the output temperature and pressure of the heat transfer fluid is close to the surrounding temperature and pressure, the process has used most of the thermodynamic potential available (it has destroyed most of its exergy).

Using this principle instead of the single energy conservation principle (first law of thermodynamics) makes it possible to overcome a limit of the caloric method, which considers the energy consumption of each application but not their thermodynamic efficiency.

5.1.4. *Opportunity cost method*

This method is not a proper allocation method. It includes no preliminary stage to estimate joint costs and the levelised cost of thermal energy. Instead, based on market conditions, the opportunity cost of producing one product (or the loss of potential gain from producing the other product) is used as the cost of this product. This method is usually employed to derive the cost of the least important product (the secondary product which is usually the non-electrical one).

Exactly as in the credit allocation methods, two plants with equal thermal capacities are considered (one imaginary single-purpose plant and the actual cogeneration plant), but only the revenues from one product sales from each plant are used to derive the opportunity cost.

If the single-purpose plant produces power (annual production E_1), its revenues are estimated based on the electricity market price p_E (average annual price or actual data). Then the revenues from saleable electricity (E_2) of the dual-purpose plant are estimated based on the same market price. The difference between the two revenues is the opportunity cost of the non-electrical product (annual production P): $p_E \times (E_2 - E_1) / P$.

This business-oriented costing method is useful to estimate the minimum selling price for the secondary product, making sure that the secondary application does not impede the primary production and its revenue stream. Yet, to set the price of the secondary product, it is usually necessary to add the application-specific costs (C_{NE} / P) or at least to check if the minimum price is higher than these costs.

5.1.5. *IAEA's cost allocation method*

The International Atomic Energy Agency recommended a methodology for allocation of cost of cogenerated product which is based on costs – like the credit cost allocation methods discussed earlier in this section. It considers two additional costs of cogeneration as follows:

- additional costs resulting from plant modifications to enable cogeneration;
- lost electricity revenue due to cogeneration.

It considers a reference plant generating E_0 amount of electricity only at a unit levelised cost c_0, leading to the total cost (capital costs, fuel and operating costs and taxes), $C_0 = c_0E_0$. If the plant is modified for cogeneration, the total cost would increase to C_1. The unit cost allocated to the P amount of cogenerated product is calculated as follows:

$$LCONE = [(C_1 - C_0) + c_0\ (E_0 - E_1)]/P$$

The above approach allocates the cost of cogenerated product at the plant level. There may be additional costs of transporting the product to the consumer, as in the case of district heating or hydrogen.

In practice, the allocation of joint costs may strictly follow the previous methods or a variation of them. This depends on the business model of the cogeneration application, the market conditions or the purposes of the cost analysis. In some cases, especially if one the applications produces a by-product, there may event not be any cost allocation.

By-products and minor co-products

In cogeneration plants, by-products are formed by secondary applications that have no impact on the operation and economics of the primary application. In nuclear cogeneration plants, there are fewer examples of by-products than co-products, mostly because they are less documented.

To illustrate possible situations involving a by-product, consider low-temperature applications. The waste heat of some single-purpose nuclear power plant is usually close to 60°C. This temperature is very low compared with the requirement of most industrial applications (see Figure 4.5) and yet it is higher than the surrounding temperature. Any application satisfied with this temperature should be able to use this waste heat at no cost. Indeed, nothing justifies considering joint costs in this situation since the secondary application does not impact the operations or the economics of the plants and the design of the plant was not adapted to it: it is free to start or stop operating without any consequences.

This situation could arise in agri-food applications which usually requires heat at temperatures below 100°C. As mentioned in Chapter 4, desalination could also be possible if the multi-effect distillation (MED) technology improves. Examples of pure by-products of nuclear heat have also been reported for applications with limited overall energy requirements like greenhouse heating in animal parks.

In those situations, no allocation method is used and using one would obviously lead to an unfair cost breakdown. For instance, if a by-product application uses all the waste heat of a nuclear power plant (approximately 60% of the overall thermal energy production), then the caloric allocation method would charge it approximately 60% of the construction costs for infrastructures, nuclear vessel and steam generator.

This obvious example of a misuse of allocation methods helps explain why some allocation methods are preferable to others in the case of minor co-products. There are many examples of secondary applications producing minor co-products, i.e. co-products that have a minor impact on the operation and the economics of the primary application (usually power production). Indeed, in most cases, district heating is a minor co-product of nuclear heat. For instance, in Switzerland, the Beznau district heating system uses between 2 and 80 MW_{th} of the thermal energy of the nuclear power plant and every 8 kW_{th} used for heating is a loss of approximately 1 kW_e of power. Therefore, the maximum loss of power production is 10 MWe, which is 1.4% of the plant capacity (2 × 365 MW_e).

If the district heating application had not been using the waste heat of the plant, the power production loss would certainly be closer to 1 kW_e every 3 kW_{th}, i.e. the thermal efficiency of the turbine. This means more than half of the energy used for district heating is waste heat. Therefore, recalling the example of misusing the caloric allocation method, it is recommended to use the opportunity cost method or the power credit method when dealing with minor co-products.

Business models and market conditions

None of the previous allocation methods outperform all the others but some allocation methods better suit specific business models.

For instance, if one application is economically dominant over the other (higher revenue streams), the credit allocation methods are preferable.

Besides, if both products are sold under fixed price contracts, the proportional value method is certainly one of the best choices to consider. The market-based variants of the power/non-electrical product credit methods would also be appropriate options.

On the contrary, if the market conditions are changeable (price variations, new competitors etc.) or if the commissioning of the plant is expected to deeply affect the market, the previous method should probably be used carefully, and methods based on energy inputs like the caloric and exergetic methods would be more robust.

Intended purposes

Finally, the experience from the Swedish conventional CHP plants shows that no specific allocation method stands out and that in most cases no allocation method is used for decision making or financial reporting purposes (Overland and Sandoff, 2014). This study also shows that the CHP owners would use different allocation methods for pricing purposes, for environmental reporting and for taxation issues as allowed by the respective jurisdictions. Besides, the choice of the allocation method is said to have a substantial impact on the business profitability.

5.2. **Examples of advanced economic analysis in nuclear cogeneration projects**

Using the cost allocation methods presented in Section 5.1, additional economic data (application-specific costs) and appropriate economic analysis tools make it possible to study and compare entire cogeneration projects (i.e. including the nuclear plant and the adjacent plants for cogeneration applications).

5.2.1. ***Economic analysis in desalination projects***

The International Atomic Energy Agency (IAEA) has developed a specific tool (Desalination Economic Evaluation Program, DEEP) to conduct an economic assessment of desalination projects powered by nuclear energy and compare them with fossil fuel-fired alternatives.

The tool needs input data on the nuclear plant and the desalination plant (size, investment cost, O&M costs, etc.) but the user can also refer to predefined industrial facilities for which all costs are already available. The costs of electricity and water are then computed and the user can perform sensitivity analysis, compare scenarios and compare the nuclear cogeneration option with other alternatives based on the cost of water.

To compute the costs of electricity and water, DEEP uses the power credit method as its cost allocation method (see Section 5.1). Many desalination projects have used DEEP or a similar approach to perform their economic assessment (see Nisan and Dardour [2007], IAEA [2007] as well as the economic assessments of the case studies in Japan and Korea in Chapter 6). Recently, a study on nuclear desalination using the MED process pointed out that when the requirements of the desalination plants can be almost entirely satisfied by using waste heat from the reactor, the power credit method may not be the best allocation option. Rather, the study recommends using the exergetic method (Nisan and Dardour, 2007). Improvements in the DEEP code are expected in this respect.

5.2.2. ***Economic analysis in district heating projects***

For district heating projects, there is no turnkey tool publicly available equivalent to DEEP. However, since district heating mainly consists of managing steam or hot water flux using pipes and pumps, the bottom-up cost assessments are easier to implement than for desalination. The

IAEA has developed a tool called WAMP (Water Management Program) which may facilitate the implementation of the complete methodology to compute the cost of heat and electricity.

For insight on how economic assessments have been implemented in district heating projects, it is helpful to consult the French case studies by Safa (2011 and 2012) related to the Paris area and the case study detailed in Chapter 6 related to the Lyon area, as well as the Swiss (in operation), Finish, Slovenian or Hungarian case studies, all detailed in Chapter 6.

When specified, these economic studies mostly used the opportunity cost allocation method:

- Finish case study: not available (the economic analysis was carried out by Pöyry engineering company on behalf of Finnish utility Fortum, as part of the application for a "decision in principle" for a new nuclear unit in Loviisa, situated about 100 km from Helsinki, no reference available).
- French case studies: opportunity cost method complemented by a net present value analysis[3] (Lyon area), or a net present value analysis only (Paris area).
- Hungarian case study: no allocation method specified, complemented by a net present value analysis.
- Slovenian case study: no allocation method specified, complemented by a net present value analysis.
- Swiss case study: opportunity cost.

The opportunity cost method is certainly the most suitable when the nuclear power plant already exists and operates; it allows the district heating application to be considered as an extra source of revenues, not interfering with the existing business model. However, other methods, like the exergetic method, could be suitable. A general recommendation would be to systematically specify the allocation method used in the economic analysis and test the sensitivity of the cost analysis by changing the allocation method prior to any net present value exercise. The development of turnkey software like DEEP could help harmonise the general economic methodology for district heating projects.

5.2.3. *Economic analysis in hydrogen production projects*

For nuclear-based hydrogen production, the IAEA has developed a specific tool (Hydrogen Economic Evaluation Program, HEEP) to conduct the economic assessment. It includes a cost database for low-CO_2 hydrogen production technologies (high-temperature electrolysis, high-temperature thermochemical cycles, low-temperature electrolysis) instead of desalination technologies. HEEP accounts for transport and storage costs, which makes it possible to consider both centralised and distributed business models for hydrogen production and distribution.

To compute the costs of electricity and hydrogen, HEEP uses the same cost allocation method as DEEP (power credit method, Section 5.1). This is open to criticism since the technological pathway to hydrogen production is not as clear as for desalination. Instead, some nuclear-based hydrogen production systems were designed as single-purpose reactors devoted to high-temperature hydrogen production or with limited electricity production. In this case, the use of the power credit method is risky since it requires considering a completely different system (an imaginary single-purpose reactor devoted to electricity production). This is probably why a different cost allocation approach has been used for these systems: the exergetic method as seen in Gomez (2008) and Gomez et al. (2007). Besides, some nuclear-based hydrogen production systems were designed to produce hydrogen only when electricity is cheap (to minimise the loss of revenue for the cogeneration plant). For these systems, a method based on the market value of electricity has been considered (Miller and Duffey, 2005). Therefore, it is recommended to use the proportional value method rather than the power credit method in this situation.

3. See dedicated subsection bellow in the recommended economic analysis workflow.

Two case studies in Chapter 6 are dedicated to nuclear-based hydrogen production. The Japanese case study considers three cases based on a very high temperature reactor (VHTR) (heat-only mode, cogeneration mode, electricity-only mode). The three cases are compared based on a cost-benefit analysis. Only the second case requires a cost allocation method, which has not been specified. The Korean case study is also based on a VHTR reactor. Only one case (heat-only mode) is considered and does not require any cost allocation method (a conventional financial analysis was conducted to estimate the return on investment of the project). In Annex A.2, a comparison of hydrogen costs is done by two tools, G4ECONS v2.0 and HEEP for a Canadian supercritical water reactor (SCWR) coupled with high-temperature steam electrolysis. The hydrogen costs estimated by the two tools showed a remarkable consistency over a range of sensitivity analysis; as both G4ECONS v2.0 and HEEP use the power credit methodology. The IAEA described in a recent publication the various tools available for nuclear hydrogen economics and benchmarking with the IAEA's HEEP software (IAEA, 2018).

5.2.4. *Economic analysis in other cogeneration applications or based on generation IV reactors*

The Economic Modelling Working Group of the Generation IV International Forum has developed a tool (G4-Econs) to facilitate the economic assessment of advanced reactor systems. Some of these systems may include cogeneration applications and the tool makes it possible to take them into account in the cost analysis. The cost allocation method is the same as in the DEEP software developed by the IAEA (power credit method). Since G4-Econs can be used to model any cogeneration application, it is recommended to first investigate the relevance of this allocation method as the previous paragraphs showed it may not be appropriate in specific situations. It would also be a good improvement to add alternative allocation methods in the software.

Indeed, among the other potential nuclear cogeneration applications, some may require specific methods. For instance, the case study of Chapter 6 dedicated to cogeneration for biorefining uses the opportunity cost approach. The Canadian case study in Chapter 6 also refers to dual-purpose nuclear power plants and potential applications in the sand oil sands (steam-assisted gravity drainage [SAGD] process). Specific methods may be required for the economic analysis of such systems.

5.2.5. *Economic analysis of nuclear-renewable hybrid energy system (NRHES)*

In the nuclear-renewable hybrid energy system (NRHES), the allocation of energy (thermal and electrical) is decided by the market prices of electricity and the industrial product. Electricity production is preferred when demand and prices for electricity are high. On the other hand, the energy is diverted to industrial processes during the periods of low electricity prices. The objective of deciding on internal dispatch is to maximise profits for the integrated system. Thus, an NRHES can alleviate the impact of low or negative electricity prices caused by over-generation. The economic analyses are often performed to optimise the sizes of NRHES subsystems and their optimal operating periods. Such analyses assume fixed operation and maintenance costs for the subsystems, and use market prices of electricity and industrial product as key inputs. Economic analyses of four different NRHESs are presented in a US Department of Energy (DOE) paper (Ruth et al., 2019), using a tool for multiple technology integration and optimisation, the REopt developed by National Renewable Energy Laboratory. Optimisation is based on net present value of the cash flow over the project life. Some of the characteristics of an economically viable NRHES, based on these analyses, are listed below.

- All subsystems of an NRHES have a positive net present value (NPV) independently, otherwise they are not included in the NRHES.
- High capital cost subsystems of the NRHES operate for the maximum possible hours.
- Lower capital cost industrial processes provide the flexibility to switch between electrical output and industrial production more often than capital-intensive industrial processes.
- Nuclear thermal energy is competitive if the heat market exists and is accessible to the NRHES.

5.2.6. *Recommended workflow for economic analysis and cogeneration project comparison*

This section reviewed several economic analysis tools and workflows for nuclear cogeneration projects. A summary of good practices is proposed.

Production costs

Before investigating the financial aspects of cogeneration projects and comparing different scenarios or project alternatives, it is a good practice to conduct a cost analysis regardless of the potential benefits. When dealing with cogeneration plants, the question of allocating the joint costs must be addressed at an early stage.

Net present value

Once the cost of each product has been determined following the most appropriate allocation method, a complementary financial analysis can bring interesting insights: evaluation of benefits, comparison of project variants or technological alternatives based on the financial performance of the project. These comparisons are usually done using the NPV approach or alternative financial indicators (Return on Investments, Payback time, etc.).

Real options analysis

The real options analysis approach offers a useful alternative to the NPV approach in the case of cogeneration projects (Hampe and Madlener, 2012). The authors applied the return on assets method to high-temperature nuclear cogeneration and claim that it gives more insight into the returns of a nuclear project than the NPV approach, since it allows reversible decisions, takes into account uncertainties and offers the option of delaying an investment. Indeed, considering sequential strategies is relevant in cases where a nuclear power plant was built before considering a cogeneration application, which is currently the case of most operating cogeneration projects.

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Chapter 6. Case studies

6.1. Nuclear cogeneration in Finland

6.1.1. *Development of nuclear cogeneration in Finland*

The plans for nuclear heat started in Finland in the late 1960s. The city of Helsinki was planning for a cogeneration nuclear plant that would produce heat and electricity to the city of Helsinki. Besides a large nuclear reactor, also smaller, heat-only reactors were considered. The ABB Atoms SECURE reactor was seen as a reliable solution and 38 locations were nominated for the nuclear heating plants. Although SECURE was considered the most feasible solution for the city of Helsinki, until the start of 1980s Helsinki did not want to be the first to build the reactor and the plans were discarded.

Loviisa 1 and 2

The possibility of generating district heat for the Helsinki metropolitan area from Loviisa's two existing nuclear power plant units was investigated in the 1980s, but it proved unpractical at the time. The idea became more attractive years later, as concerns about climate change grew and highlighted the advantages of decreasing Finland's carbon dioxide emissions significantly.

An updated study was made as a master's thesis in spring 2016 (Fortum, 2016) on the possibilities to use the excess heat from existing units in Loviisa as district heat. The results are presented in more detail in Section 6.1.2.

Loviisa 3

While Fortum applied for a Decision in Principle concerning the construction of a new nuclear power plant unit (Loviisa 3) in 2009, the possibility to cogenerate district heat to the metropolitan area was studied. The new Loviisa 3 reactor, with a range of 2 800-4 600 MWth, would be located on the southern coast of Finland.

The main alternative investigated was a cogeneration plant designed for large-scale district heat generation for the Helsinki metropolitan area, which is located approximately 75 km west of the Loviisa site. The starting point was that the district heat generation capacity of the Loviisa 3 unit would be around 1 000 MWth.

The district heat consumption in the Helsinki metropolitan area is on average 10-11 TWh per year, depending on how cold the winter is. Generally, the district heat consumption in the region varies from a minimum of approximately 400 MW during the summer to 3 000-3 500 MW peak load during the winter. The Loviisa 3 unit could ideally provide a significant portion of the district heat baseload needs of the Helsinki metropolitan area. The district heat consumption in the Helsinki metropolitan area is higher than 1 000 MW for 62% of the year (Bergroth, 2010).

Hankikivi

Fennovoima, a Finnish company planning to build a greenfield nuclear plant in Pyhäjoki Finland, was also studying the opportunity for simultaneous district heating production in its application in January 2009 for a government Decision in Principle regarding the construction of a nuclear power plant. Fennovoima explored the technical requirements for district heat production for each power plant alternative, and for heat transfer and district heat consumption at all alternative sites.

In the district heating alternatives, the amount of residual heat released into the environment with the cooling water discharged was significantly reduced. On the other hand, district heat production reduced the electricity output of the nuclear power plant by about 1 MW per 4 to 5 MW of district heat (Fennovoima, 2009).

District heat production at the nuclear power plant can replace conventional district heat production within reasonable transfer distance from the power plant. Among the Fennovoima shareholders, Porvoon Energia, Vantaan Energia and Keravan Energia are significant producers and distributors of district heat within a technically feasible transfer distance of Ruotsinpyhtää, on the southern coast. Fennovoima was prepared to offer district heat to energy companies in Helsinki and its vicinity if the site selected was Ruotsinpyhtää (Fennovoima, 2009). However, the location selected was Pyhäjoki, on the north-west coast of Finland, where there are fewer consumers for district heat. The district heat alternative has therefore not been a topical issue anymore.

6.1.2. *Production solution for using Loviisa's existing nuclear units for combined heat and power production*

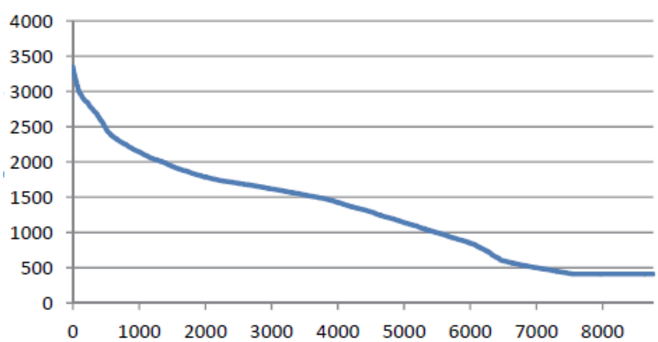
Fortum and previously Imatran Voima have for decades examined and developed the idea of producing nuclear district heat, since using waste energy for heat production could raise the efficiency of the nuclear plant substantially and generate new revenue. One of the main points was to study the feasibility of Loviisa's existing nuclear power units for combined heat and power (CHP) production.

District heat demand

Nuclear district heat (DH) production is encouraged by the high annual demand for heat in the Helsinki metropolitan area, the potential to reduce dependency on volatile electricity markets and the positive environmental impacts. The share of district heating is very high in the metropolitan area. District heating demand is expected to decrease slowly due to more energy efficient buildings from the current 10 TWh to 7 TWh in 2050 (Fortum, 2016).

The DH peak load will be around 3 000 MW in 2013 and demand will be over 1 000 MW, approximately 5 500 hours per year, making the load quite suitable for nuclear district heating.

Figure 6.1: **Duration curve of district heating demand in 2030**

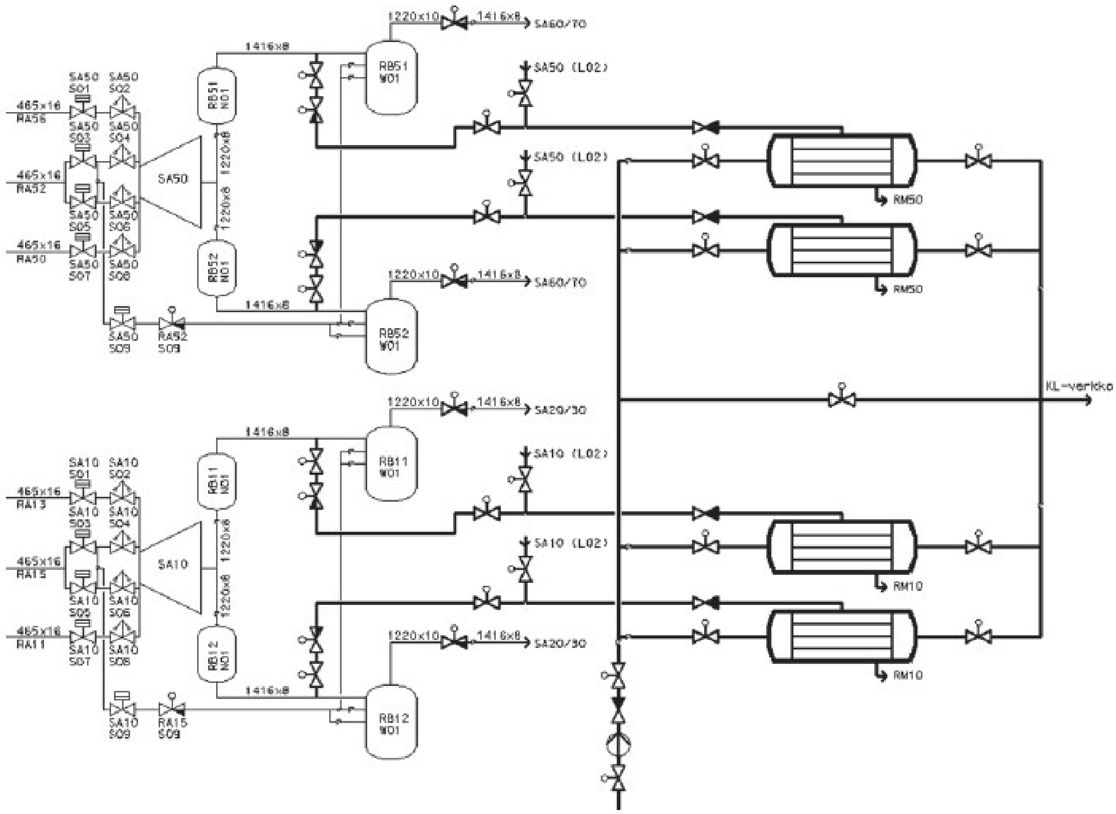


Source: Fortum (2016).

District heat connection

The district heat connection can be made to the existing nuclear units through steam extraction, in which the needed steam is taken from high-pressure turbines to the heat exchangers. After the high-pressure turbine, the steam values are adequate for district heat production. Each turbine has two steam lines leading to district heat exchangers so that the size of the steam lines remain moderate. The steam lines are equipped with shut-off and control valves and non-return valves, which allow the steam flow to be controlled and prevent backflow to the turbine.

Figure 6.2: **District heat connection**



Source: Fortum (2016).

Another option to obtain district heating from existing condensation-based nuclear power plants would be to invest in a new back-pressure turbine that could serve both reactors. This option has not been evaluated here.

The performance of a secondary circuit under variable district heat power was studied in collaboration with Fortum and the Lappeenranta University of Technology. Findings show that the maximum capacity of one turbo-generator is 495 MW heat without significant modifications.

After the steam extraction from the outlet of the high-pressure turbine, the steam flow to the low-pressure turbine decreases significantly, which may lead to significant changes in the mass flow and pressure level of the extraction steam. A relative pressure ratio at the last zone of the high-pressure turbine increases significantly, which may lead to changes in the turbine operation. As the back-pressure level decreases, the electricity output from the high-pressure turbine increases. The electricity output from low-pressure turbine decreases as the heat mass flow through the turbine decreases.

A decreased pressure ratio increases the steam flow rate, which can increase erosion problems in the turbine and pipeline. To minimise the pressure ratio, steam flow can be throttled with a control valve after the steam extraction. This causes some additional losses.

By throttling the steam flow, the steam pressure increases quickly at the high-pressure turbine outlet. The increase in the pressure level allows an increase in the district heat output to 495 MW and by increasing throttling the pressure ratio can be kept at its normal level. As the relative pressure ratio in the last zone of the high-pressure turbine decreases it causes much less stress on structures. The expansion in the low-pressure turbine will then happen at the superheated levels, which need to be analysed separately.

The district heat output will fundamentally affect the generator's power output. Loviisa's output and efficiency estimates after the modifications to the nuclear CHP were made at the Lappeenranta University of Technology with their simulation tool IPSEpro. The results are presented in the following table (Fortum, 2016).

Table 6.1: **Technical parameters of district heating**

District heat output, MW	0	250	450	450	450	495
Throttle control, bar	-	-	-	0.5	2.0	2.73
Generator power, MW	270	226	196	188	172	157
High-pressure turbine						
Thermal capacity, MW	135	157	183	172	150	145
Low-pressure turbine						
Thermal capacity, MW	140	72	17	19	24	15
Condenser capacity, MW	482	277	107	115	132	102
Efficiency	0.36	0.63	0.86	0.85	0.83	0.87

Source: Fortum (2016).

The simulation results are promising. As the district heating output of 450 MW is produced with the steam of one turbo-generator, the loss in generator output is only 74 MWe. The district heating connection increases the overall efficiency of the system remarkably. The efficiency of the nuclear plant increases to 85% when the DH output is 450 MW and the electrical output is 196 MW.

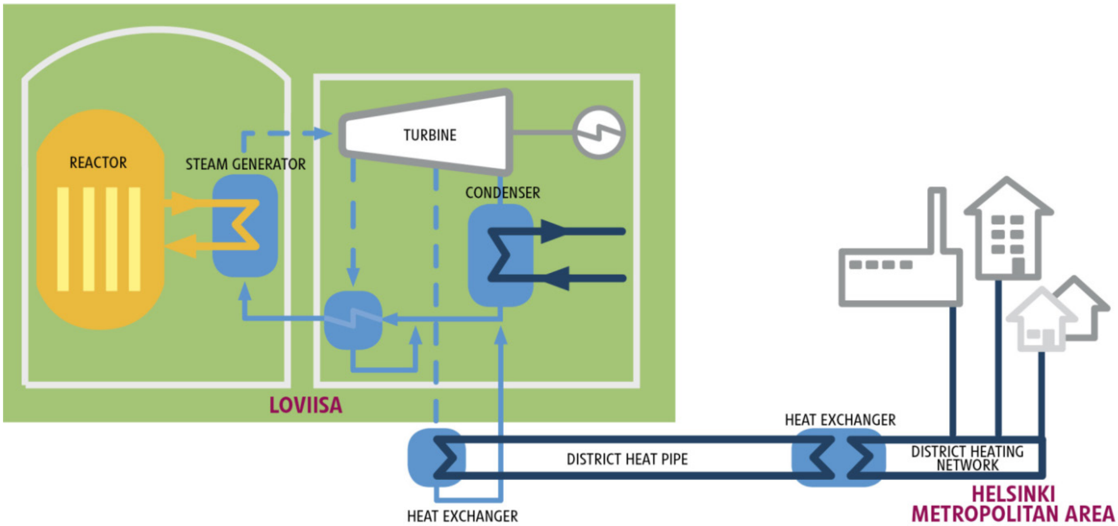
6.1.3. *Possibility to supply district heat from Loviisa 3 to the metropolitan area*

The Loviisa 3 unit will be based on advanced light water reactor technology, either pressurised water reactor (PWR) or boiling water reactor (BWR) technology. The Loviisa 3 unit would be designed from the start and optimised to generate both electricity and district heat at a large scale with high efficiency. The Loviisa 3 combined heat and power generation concept is based on a separate, closed district heat circuit where the district heat water is heated up using steam extracted from the turbine. The heated water is then pumped along a dedicated underground pipeline to the Helsinki metropolitan area, where the heat is transferred to the region's local district heat network. The cooled return water is pumped back to the Loviisa Nuclear Power Plant site, where it is reheated, and the cycle starts over again. (Bergroth, 2010)

Technical concept

Combined heat and power generation is technically possible to realise both in PWR and BWR plants. Whatever the reactor type, the district heating water is not in contact with the radioactivity of the reactor circuit. Both plant types include two physical barriers in order to reliably prevent the spread of radioactivity to the district heat transport system. In addition, pressure differences over at least one barrier are designed to ensure that, in case of a heat exchanger tube rupture, the leakage is always towards the turbine plant processes.

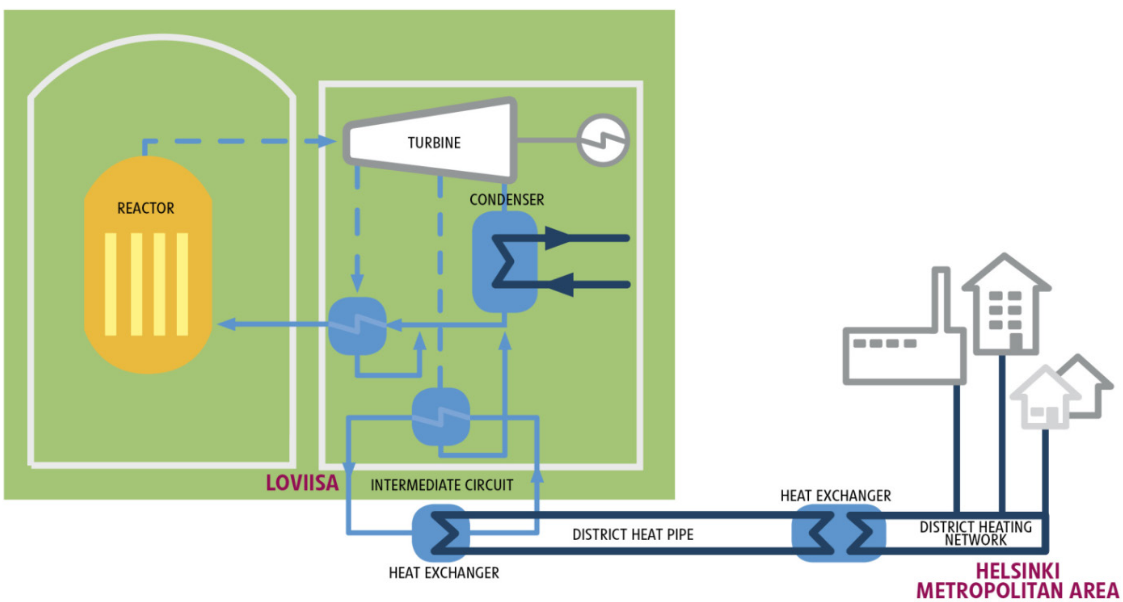
Figure 6.3. **General implementation of district heat generation in a PWR plant**



Source: Fortum (2016).

Because of the radioactivity inherently present in the turbine plant processes during normal operation in a BWR plant, an intermediate circuit is added between the district heat transport system and the turbine plant processes. The heat exchangers in the intermediate circuit form the two physical barriers against the spread of radioactivity from the reactor circuit to the district heat transport system.

Figure 6.4. **General implementation of district heat generation in a BWR plant**



Source: Fortum (2016).

Despite the large-scale combined heat and power generation, the turbine and the turbine plant would be designed so that the unit can operate also in full condensing mode with high efficiency, i.e. to generate purely electricity. This implies, in practice, that the unit is capable of generating electricity and district heat in the range of 0-1 000 MW with high efficiency. This will require somewhat big modifications to the turbine and the turbine plant, compared to conventional equivalents. In other words, generating 1 000 MW of district heat would reduce the electrical output by no more than 160-165 MW. (Bergroth, 2010)

The maximum overall efficiency could increase to approximately 55-65% in the Finnish cold cooling water conditions, depending on the considered plant alternative. The outlet and inlet water temperatures of the district heat transport system for the Loviisa 3 unit are 120°C and 54°C, respectively. In operating nuclear district heating applications, various temperature levels are used, with temperature differences in the range of 60-80°C. The highest outlet temperatures used are 150°C. The required pumping capacity is approximately 40-50 MW. (Bergroth, 2010)

Two types of pipeline concepts were analysed to serve the district heating water to the metropolitan area. In the tunnel alternative, the district heat transport system pipelines are installed in a tunnel excavated out of the bedrock. In the ditch alternative, the district heat transport system pipelines are, apart from the beginning and end, installed in a ditch excavated from the ground surface. (Bergroth, 2010)

Economic analysis

District heat generation in the Helsinki metropolitan area is based on coal and natural gas, producing some five to seven million tonnes of carbon dioxide emissions annually. Large-scale CHP generation at the Loviisa 3 unit could cut this figure by up to four million tonnes. This would decrease Finland's carbon dioxide emissions by as much as six percent. In addition, large-scale CHP generation would increase the overall efficiency of the new unit significantly and, hence, reduce the environmental impact on the local marine environment by cutting heat discharges into the Gulf of Finland. (Pöyry, 2010)

The feasibility of providing district heat from Loviisa 3 and building a district heat connection to the metropolitan area was examined by Pöyry in 2010. At that point, the city of Helsinki was in a position to make decisions on building new district heating generation capacity. The options were coal or bio-based CHP plants and nuclear cogeneration was compared with them. With the used assumptions, the nuclear scenario proved to be the most economical.

6.1.4. Conclusions

Nuclear cogeneration would suit to Finnish energy system, which has a high share of district heated buildings. The existing plants in Loviisa have a moderate distance to the metropolitan area, where the district heat provided by the plants could be fed into the existing district heating network.

District heat production at the nuclear power plant can replace conventional district heat production in the metropolitan area. District heat consumption in the metropolitan area is on average 10 TWh per year, which could guarantee peak utilisation time of over 6 000 hours for nuclear cogeneration.

The district heat connection can be made to the existing nuclear units by steam extraction after high-pressure turbines. The district heating connection would increase the overall efficiency of nuclear plants significantly. A district heat connection to the metropolitan area could be built as a tunnel, where the district heat transport system pipelines are installed in a tunnel excavated in the bedrock or as a ditch, where the district heat transport system pipelines are installed in a ditch excavated from the ground surface.

The feasibility of nuclear cogeneration is highly dependent on the investment costs and development on energy markets. A high share of low-cost hydro and renewables in the Nordic market puts any new investment decision at risk, especially for projects with high investment costs and long construction times.

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6.2. **Nuclear district heating: Economic study of a theoretical retrofit case in France**

*6.2.1. **Introduction***

In 2015 the French National Assembly ratified the Energy Transition bill ("*loi relative à la transition énergétique pour la croissance verte*") which sets out the government's targets for improving energy efficiency and reducing greenhouse gas emissions. The 2030 objectives are twofold: reducing the share of electricity generated by nuclear power (from 75% to 50%) and developing district heating networks (increase from the 2009 level of about 5% to 15%.

The French National Alliance for Energy Research Coordination (ANCRE) identifies cogeneration plants as one of the pathways towards a sustainable energy system (greenhouse gas emissions should be reduced by a factor of four by 2050). It highlights the potential of nuclear plants to be operated in a cogeneration mode, producing both electricity and heat for houses or industries. France's nuclear reactors have the potential to produce tens of $TWh_{th.}$ The electricity output would be reduced, but that would be more than compensated by the heat output. Overall, it would increase the thermal efficiency of nuclear reactors and allow the recovery of a large amount of low-carbon heat.

Nuclear district heating is of particular interest in France, since it nuclear energy sector is composed of 56 pressurised water reactors (PWR), with a new one under construction. The average lifetime of a French PWR is about 30 years. Several reactors will likely be decommissioned within ten years. For some it is technically possible to extend the operational lifetime without jeopardising the safety of the reactor. Whether or not French public authorities will take such a decision (and follow the example of the United States) is not within the scope of this research. Yet it is advisable to consider and study it as a potential scenario. This chapter focuses on retrofit of existing nuclear reactors, with a view to highlighting the areas where the extension of the PWR lifetime has the highest economic and environmental potential. It is worth noting that a new generation of nuclear reactors, designed specifically for cogeneration purposes, would be economically more attractive.

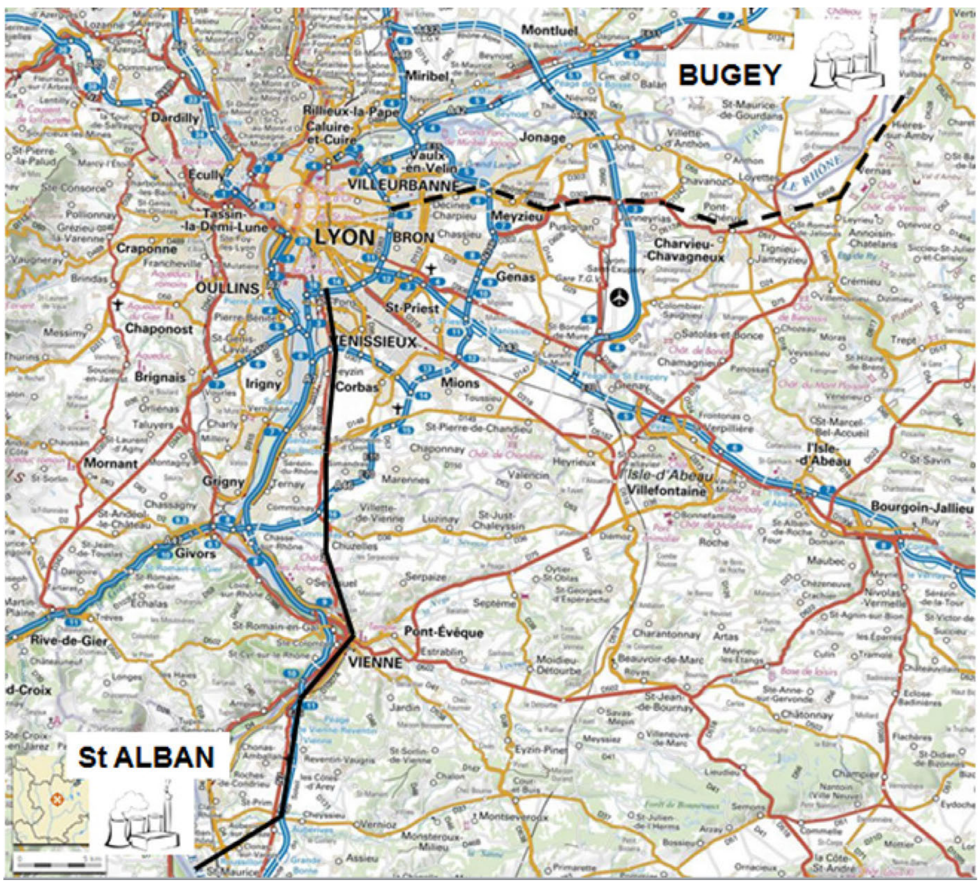
This chapter examines the retrofit of a PWR to cogenerate heat and to deliver it to a district heating (DH) network. The economics of the project have been investigated through the computation of the net present value (NPV) and the levelised cost of the heat (LCOH).

6.2.2. *Main assumptions*

A previous research project addressed the overall potential of French nuclear sites to deliver district heat. It identified the urban areas with the greatest economic potential for the development of nuclear district heating system. It discussed coupling the Nogent-Sur-Seine reactor with the Parisian district heating network. Despite being promising, the idea faces some barriers specific to the area such as the long distance to transport heat (over 100 km), strong urbanisation, and the use of steam by the main regional network. Another case studied the city of Metz and the Cattenom Nuclear Power Plant, but heat demand in this case is low, jeopardising economic profitability.

This chapter addresses a new case, that involving the city of Lyon and the St Alban-St Maurice plant, which could show competitive advantages. The nearest nuclear power plant of Lyon is Bugey, but its reactors are among the oldest in France, and thus present a high risk of an imminent decommissioning.

Figure 6.5: **Map of the studied area**



St Alban-St Maurice is a nuclear site located 35 km from Lyon, to the south. It is composed of two 1 300 MWe PWRs commissioned in 1986 and 1987. Like all French reactors, they were designed to be operated for 40 years (until 2026). Yet an extension of their lifetime is expected (following the global trend) and it is expected that they will last an additional 20 years. Starting in 2017, retrofitting the reactors for cogeneration (including preliminary studies, regulatory process, modification of the reactor, and building the transport line) could take about 9 years. One may estimate the project lifetime at 20 years, if the operational lifetime of St Alban is extended.

Lyon is a metropolitan area with 1.5 million inhabitants and containing about ten DH networks (currently disconnected). Total district heating consumption in 2015 was approximatively 1 TWh (covering the heat needs of about 15% of the population). District heating networks will likely be further developed in the future and could reach 2 TWh/year by 2030 if they follow the same pattern as expected for the Parisian area. While ambitious, this assumption is realistic. As a comparison, Grenoble, a medium-sized city located 100 km from Lyon, has a similar use of district heating networks: 700 000 MWh for 500 000 inhabitants.

The average price of heat in the region was around EUR 70/MWh in 2013 but is significantly lowered by the Grenoble network (EUR 40/MWh for a typical annual consumption of 7 MWh).

Assuming that the load period for heat is around 3 000 hours, the nuclear power plant should be adapted to provide around 320 MW_{th}.

The average carbon emissions from regional district heating networks are 180 tCO_2/KWh. Replacing the current heat supply plants in Lyon (mainly based on fossil fuels, but with an increasing share of biomass), the potential savings could represent a few hundred kilotons of CO_2.

6.2.3. *Economic model*

The model adopts a fully integrated vision of the project. All the costs and incomes are aggregated into a single result. This approach reflects the interests of society overall and diverges from an industrial point of view.

This model has been built considering that every modification required is fully payed for by heat cash flows. The related operations include the investment in the nuclear power plant to extract the heat, the operational costs of heat management, and the compensation of the electricity losses due to the extraction of heat from the nuclear plant.

The initial revenues of the plant, based on the sale of electricity, can be expressed as:

(1) $R = p_e . E$,

where p_e is the selling price of electricity (EUR/MWh[e]) and E the annual production (MWh[e]). With the cogeneration mode it becomes:

(2) $R' = p_e . E' + p_h . H$,

where p_h is the selling price of heat (EUR/MWh[th]), H the annual heat production (MWh[th]) and E' the newly reduced production of electricity (MWh[e]).

Considering that the cogeneration process should not alter the previous business model based on electricity, the cash flows generated by the heat production should also pay back the electricity losses, expressed as:

(3) $p_e . (E - E')$.

6.2.4. *Main parameters*

The overall nuclear district heating project can be considered to be composed of three main blocks: heat production (the modified nuclear power plant), heat transport from the plant to the final user (later called main transport line, MTL) and the distribution network.

The studies required to modify the nuclear power plant (mainly safety, but also regulatory and public) could cost up to EUR 70 million and the loop modification (including temporary shutdown) up to EUR 50 million. Thanks to the high standardisation of France's reactors, part of the research and safety assessment costs could be shared across several cogeneration sites. Therefore, a large-scale planning for multi-sites nuclear cogeneration would benefit from economies of scale.

The heat is transported between the nuclear power plant and the distribution network as superheated water at 100°C. In the secondary loop of the reactor this temperature can be extracted after the low-pressure turbine, thus limiting the electricity losses to around 1 MWh(e) for 5 MWh(th) produced.

After delivery of the heat to the distribution network, the fluid in the returning pipe is supposed to be at 60°C. In both pipes the fluid should be maintained between 10 and 20 bar.

The diameter of the pipes will be around 1 100 mm. This large size is the result of an optimisation between opposing parameters; the ones related to increasing costs (price of tubes, thermal losses) and others related to lowering the costs (pressure losses generating more pumping stations and higher electricity consumption).

The MTL is to be fully built before the delivery of heat can start. Building costs are based on an assumption of 35 km in the countryside (EUR 2.5 million/km) and the last 5 km of urban area in tunnels (EUR 10 million/km). Both distances are increased by a factor of 1.25 to consider the path issues and technical requirements that would inevitably occur. The considered costs are extrapolated from known costs for smaller pipes. Yet the estimate still needs to be refined as no such heavy heat transport line exists for now.

To ensure appropriate pressure in the pipes, one or two pumping station have to be built on the way. Some heat exchangers of high power will transfer the heat to the distribution network. The associated prices should be small compared to the previous ones.

The distribution network would likely need to be extended. Here such costs are not considered, as they are related to the distribution part, which is charged independently.

Considering that the projects start from existing distribution networks, the existing boilers could be used as backup facilities that would help meet peak demand. In this situation, the share of heat produced by the nuclear plant and these auxiliary boilers needs to be optimised. Their amortisation and operation must be taken into account because they will not be used as frequently as initially expected when designed. For now, too many uncertainties limit this calculation, but the corresponding impact on the final LCOH should be small.

The price of heat is assumed to be EUR 45/MWh(th). It corresponds to the current variable part of the average price of heat in this region. Indeed, this report considers that the fixed part is devoted to infrastructure management for distribution, while the variable part represents production, which will be replaced by the nuclear plant and the transport line which make up the investment of the project.

The price of electricity is assumed to be EUR 40/MWh(e). This price affects operational costs, both for the modification of the system (mainly pumps) and especially the compensation for electricity losses due to the extraction of heat from the reactor.

The discount rate applied is equal to 3%. Despite being low compared to the rates applied by private investors, such a level reflects the fact that strategic, environmentally friendly projects should not be endorsed by a single private investor.

Finally, CO_2 emissions savings are included in the model as revenues. The “price” of carbon here applied is in line with the French law objective of EUR 100/tCO_2 in 2030.

6.2.5. *Results*

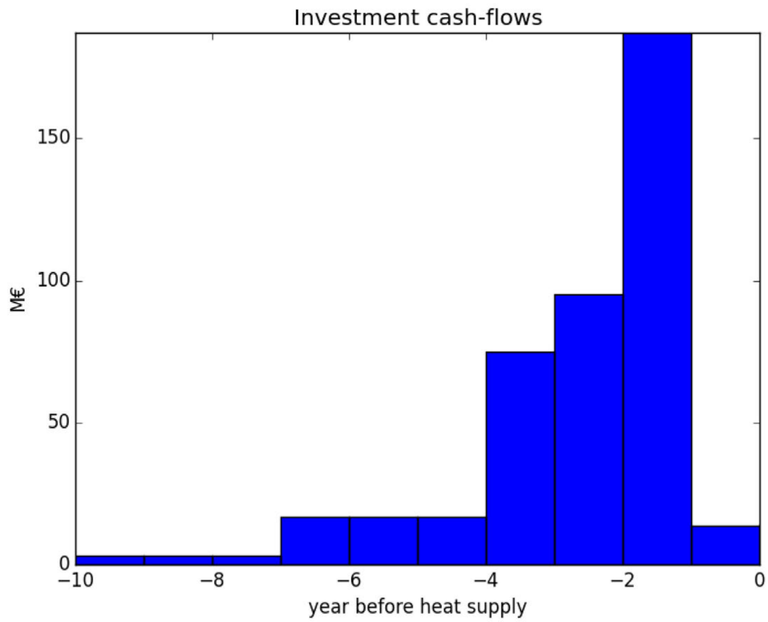
Given these hypotheses, the project seems to be economically viable with a positive NPV of EUR 140 million over the 20 years of technical lifetime, with a payback period of about 15 years.

The NPV results from an investment of EUR 400 million (EUR 370 million overnight) over ten years. Of that investment, 75% is dedicated to the transport line. Income is equal to EUR 41 million/year from the beginning of the operational phase.

During the operational phase, the largest part of expenditure corresponds to the compensation for electricity losses (expenditure of EUR 8 million/year), followed by the maintenance of the system (expenditure of EUR 3 million/year, that is 1% of the overnight investment yearly).

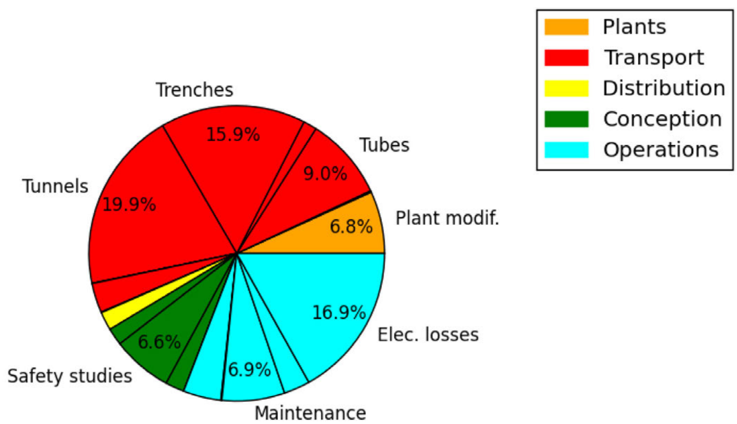
The income comes from selling the heat (EUR 43 million/year) and the equivalent-price savings on CO_2 emissions (EUR 13 million/year).

Figure 6.6: **Investments chronology**



The resulting LCOH is around EUR 48/MWh(th). It is a little more than the chosen selling price. It is the positive effect of the carbon savings (EUR 12.7 million yearly for 170 kt_{CO2} saved) that allows the project to be profitable.

Figure 6.7: **LCOH structure**



6.2.6. *Discussions*

These figures lead to a positive evaluation of the project, but some sensitivity studies are still needed to confirm the view. A variation in some dimensioning parameters (the discount rate, heat supply, building of the transport line, etc.) can affect the conclusions.

As can be seen in the results, the main part of the investment (and thus the economy of the project) is composed by the main transport line. It is therefore important to properly define its characteristics and the associated costs.

As the length of the transport line affects cost, it could be interesting to extract the nuclear heat from the Bugey Nuclear Power Plant, another nuclear site located only 25 km from Lyon. This hypothesis was not considered at first as the site's reactors are old and could be decommissioned soon. However, if a new reactor is built on the site, a cogeneration project could save a third of the investment (compared to the St Alban case), doubling the NPV.

Focusing on the building of the MTL, the assumption made of using tunnels for the final few kilometres is penalising (the associated costs being four times those of an installation in trenches). Here again, a third of the investment could be saved if the tunnels prove to be unnecessary. On the other hand, increasing the length of the tunnels (e.g. for environmental reasons) would strongly jeopardise the profitability of the project.

The discount rate is another important input parameter. The actual internal return rate (IRR) is just above 5%. As the project lifetime is quite long (10 years of investments and 20 years of operations), a high rate is not compatible with such a mega-project. That would mean the project does not fulfil private investors' expectations, and would not be implemented without state intervention.

The level and evolution of heat demand are difficult to assess, but critical. Starting from an existing supply of 1 $TW_{th}h$ in this region, the development of district heating networks faces two contradictory processes. Their extension is encouraged to increase energy efficiency and decrease CO_2 emissions; but new building needs are lower due to better energy efficiency and old buildings are encouraged to carry out thermal insulation works.

It could also be interesting to investigate the possibilities for nuclear cogeneration to provide process heat for industries. Insight from the French National Alliance for Energy Research Coordination (ANCRE) highlights a potential market of 1 to 2 TWh around the St Alban's site. Such usage and market are quite different from district heating (e.g. temperature and regularity of the heat supplied). There is a need for identifying more precisely many parameters (locations, temperature, power, pricing, etc.). Yet these regions already think about such usages. It could be a promising market for nuclear cogeneration, enhancing regional synergies.

The last points this chapter focuses on are the prices of energy: electricity, heat and CO_2.

The most important factor influencing our results is the selling price of heat. Its current pricing provides a stable environment for district heating networks and it is expected to continue to do so in the following decade.

Volatility in electricity prices makes any projection uncertain. A low price is favourable to the deployment of alternatives, such as electricity-intensive technologies (e.g. heat pumps), but it also increases the economic profitability of nuclear cogeneration projects (by reducing operating costs). High electricity prices lead to an increased commercial importance of electricity output, and hence limit the willingness to consider nuclear cogeneration.

Finally, the carbon price and its integration into the economic assessment is critical since it can allow environmentally friendly projects such as nuclear district heating to be profitable.

*6.2.7. **Conclusions***

These preliminary results, even if they are still only partial and require confirmation by comprehensive specific case analyses, offer hope for significant development of this promising technology.

However, this technology has yet to be validated on the scales envisaged here, in particular for existing reactors, which are the subject of this study. At least two specific questions relate to such reactors. The first concerns the long-term sustainability of centralised electricity production sites (which affects the ability to generate heat over time), which in turn depends on the combination of the remaining operational life of the existing reactors and the viability of future investment in the sites or in the local area. The second is the question of scheduling the work needed to modify the standard reactor design, which would involve new regulations (governing heat production), is costly, and may be accompanied by a loss of production while work is carried out.

The model described here is adapted to the deployment of cogeneration within existing reactors. It will be important to examine this issue for new reactors, considering that such projects would offer a better overall design, no disruption associated with upgrading a unit in service, and a longer planned service life. But considering a new reactor implies completely reshaping the economic model, as heat and electricity have to share all the investments and operational costs.

The questions around the price of heat also argue in favour of completing this study with a full-system approach, including prospects about energy consumption and the technology that match. The nuclear cogeneration cannot be considered alone but must face some competitors within a changing environment. The high investments and the long-term operation times of this technology discourages private investment, proving once again the need for political support to promote this low-carbon heat source on sites were it is technically and economically feasible.

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6.3. Cogeneration in the Krško Nuclear Power Plant in Slovenia

6.3.1. *Introduction*

In Slovenia, as in the broader European Union, sustainable development is of increasing interest. In local energy supply, district heating based on sustainable sources and on the highly efficient cogeneration of heat and electricity production plays an important role. Nuclear energy can be included among the sustainable sources, alongside renewable energy, since it is one of the cleanest and most competitive.

GEN energija completed a first feasibility study on cogeneration in 2007, when it analysed the possibility of waste heat utilisation for the planned Krško 2 Nuclear Power Plant (JEK 2) (GEN Energija, 2007). But since the project was postponed, a similar study was done for the Krško Nuclear Power Plant (NEK). A comprehensive analysis and comparison of several heat sources (e.g. nuclear, biomass, geothermal, and gas) that could potentially be used for the district heating was carried out. The study included an estimation of the range of potential consumers in the nearby region, an estimation of annual heat demand, and an analysis of the environmental impact and the economic feasibility of different scenarios.

GEN energija also conducted a feasibility study on production of hydrogen using heat or electricity from NEK (GEN Energija, 2010). Technologies that are already commercially available and those that are in development were also considered. Using steam for hydrogen production is a matter of interest because it increases the efficiency of the power plant. However, all the considered technologies that could utilise steam would require much higher temperatures than the ones available in NEK. The only available technical solution is to produce hydrogen from the water by means of electrolysis. However, this process is very expensive compared to the chemical processes that are currently commercially used for hydrogen production. Therefore, utilisation of heat for hydrogen production is not examined in this report.

6.3.2. *Heating and cooling needs in the local area*

NEK is located on the northern bank of the Sava River, approximately 2 km south east of the town Krško in Southeastern Slovenia. The existing Krško Nuclear Power Plant started to operate in 1983 with a 40-year design lifetime. However its operation is due to be extended until 2043. In addition, GEN energija is considering building a new unit.

Various potential uses for heat in the area of Krško and Brežice were identified. The most promising are:

- heating;
- cooling;
- use of steam in industry; and
- use of heat in agriculture.

District heating

District heating systems are increasingly common, both in Slovenia and around the world. District heating by means of CHP production can significantly reduce environmental impact, but also increase the energy efficiency of a power plant. However, not many nuclear power plants are connected to district heating systems.

Krško and Brežice have a diverse heating source structure. The current systems are mainly based on biomass, natural gas, oil and electricity – heat pumps.

In order to analyse the technical and economic feasibility of the project, a survey for potential heat need was performed.

Four main groups of potential district heat consumers have been identified:

- consumers connected to major common boiler houses;
- public buildings;

- major individual boiler houses;
- other consumers (e.g. detached houses, cafes, business premises and other potential consumers not classified in one of the above given consumer groups).

Table 6.2 gives the most important estimates on heat consumption in the areas of Krško and Brežice.

Table 6.2: **The assessment of heat consumption for district heating of Krško and Brežice**

Facility/building	Anticipated heat consumption (GWh/year)		Share of heat consumption (%)		Energy Utilisation Index (kWh/m^{2}a)	
	Krško	Brežice	Krško	Brežice	Krško	Brežice
Major common natural gas-fired boiler houses	8.6	8.0	16%	16.4%	158	151
Public buildings	1.7	4.1	3.1%	8.4%	100	109
Major natural gas-fired boiler houses	4.8	388	8.8%	0.8%	137	165
75% of other consumers	36.2	30.5	66.9%	62.3%	159	154
Total (75% of other consumers)	51.2	43.0	—	—	—	—
Future new consumers	2.8	5.9	5.2%	12.1%	—	—
Total heat consumption (75% from the category of other consumers)	54.1	49.0	100%	100%	—	—

Source: GEN Energija (2013).

The total heat demand was estimated based on the following assumptions:

- all public buildings will connect to district heating;
- 75% of privately owned households will connect to district heating;
- energy efficiency measures will take place soon; and
- population numbers will increase slightly in the future.

Considering the above assumptions and considering an additional need of 20 000 MWh/year for sanitary water, total annual heat demand could be approximately 123 GWh/year.

Total installed power of the heat source was defined at approximately 70 MW_t based on a conservative estimate of the concurrency factor[1] of 0.72, the assessed power required for hot sanitary water preparation, and the power required to cover heat losses in the district heating system (estimated heat losses amount to 11 600 MWh/year).

District cooling of Krško and Brežice

In the Krško and Brežice area, cooling requirements are mostly met by the local compressor cooling systems. District cooling by means of a central absorption chiller can be a perfect solution for big buildings in high density areas (e.g. shopping centres, office buildings, health care facilities and schools). District cooling could represent an additional service next to district heating. Combining heating and cooling would also argue in favour of a baseload operation.

The analysis showed that the district cooling system would have higher costs compared to the current situation with individual compressor cooling system solutions. The main reason is the relatively low concentration of the cooling needs. Thus, the district cooling system for Krško and Brežice area is not economically justified and no technical solutions are presented in this report.

1. The concurrency factor describes the ratio between the maximum simultaneous heat demand of all customers and the total subscribed connection load.

Use of steam in industry

Potential NEK industrial steam consumers are the nearby companies Vipap Videm Krško d.d. (Vipap) and Krka, d.d. Vipap is the largest paper production factory in Slovenia, while Krka is an international generic pharmaceutical company. Both companies use their own boilers for steam production. Krka uses gas whereas Vipap uses coal, biomass or gas. Due to the old technology as well as environmental limitations regarding coal-fired boilers, Vipap will not be able to produce the steam any longer by means of obsolescent boilers. The production of steam from NEK presents a good alternative to the currently used or any other available steam sources. The cost of steam produced in NEK would be very competitive compared to the steam source systems in nearby industrial facilities as well as to any other alternative solutions.

The steam capacity requirements are as follows:

- steam of 12 bar (abs) pressure, 188°C temperature for Krka: 16 t/h;
- steam of 4.6 bar (abs) pressure, 190°C temperature for Vipap and Krka: 60 t/h.

Use of heat in agriculture

District heating is also suitable for agricultural needs. Heat is mainly used in greenhouses for faster and more controlled cultivation of plants, both fruits and vegetables. Due to climate conditions, reheating is necessary in colder days during the late autumn, winter and in early spring. Table 6.3 represents parameters for agriculture heating needs.

Table 6.3: **Parameters for agriculture heating needs**

Parameter	Value
Greenhouse heating area	17 000 m^2 (11 000 m^2 Brežice, 6 000 m^2 Krško)
Estimated average specific heating power	140 W/m^2
Estimated heating power	2.4 MW
Estimated heat consumption	4 000 MWh per year

Source: GEN Energija (2013).

Use of heat in agriculture could represent a parallel activity next to district heating. The system could operate in the low-temperature regime (40 to 60°C), which would have a positive effect on the efficiency of the whole system. However, high dispersion and the relatively large distances to the greenhouses mean the investment costs of the distribution system are high and the use of heat from NEK is not economically justifiable.

6.3.3. *Possibilities of heat utilisation*

This section presents two alternative sources for district heating and one for industrial steam, which were identified in Section 6.3.2 as suitable. Other options were also analysed in the feasibility study, but due to technical or economic reasons they are not feasible and therefore not included in this report.

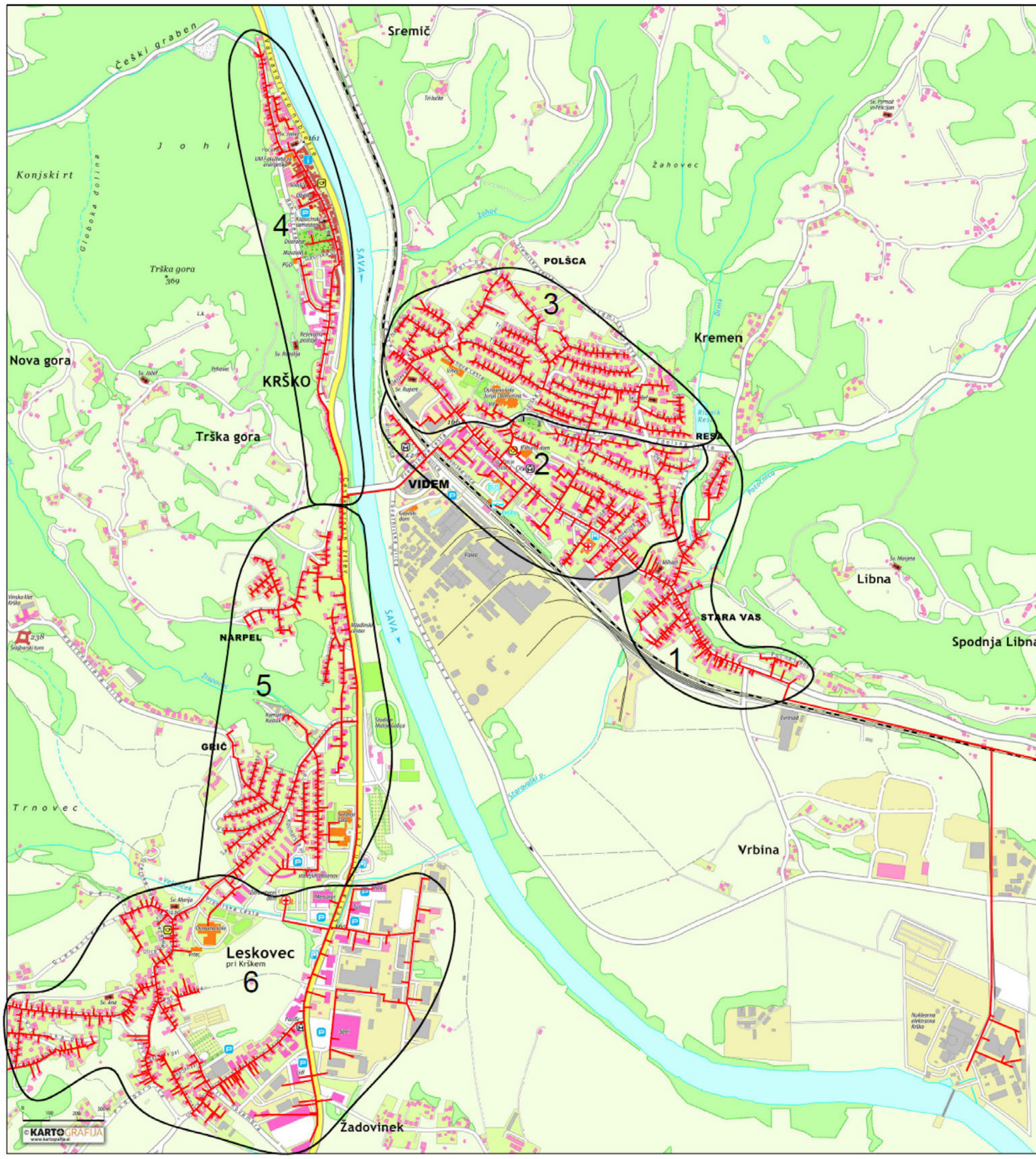
District heating

- District heating system characteristics

The district heating system of Krško and Brežice has been designed for the area, which is populated by approximately 14 500 people. In the Krško area there are around 8 000 residents and in Brežice around 6 500. The NEK, which is a suitable potential heat source for the district heating system supply, is located several kilometres from the consumers. In the section where the pipeline diameter is the largest, the length of the main hot water line running towards Krško is approximately 2.3 km. The total length of all branches within the Krško distribution system amounts to approximately 44 km. The length of the route extending from the heat source to the most distant consumer in the Krško region is about 7 km. Compared to Krško, Brežice is a little farther from the heat source. In the section where the pipeline diameter is the largest, the length of the main hot water line running towards Brežice is approximately 7.8 km while the total length of all branches within Brežice distribution system is about 45 km. The length of the route extending from the heat source (NEK) to the most distant consumer in Brežice is approximately 12 km.

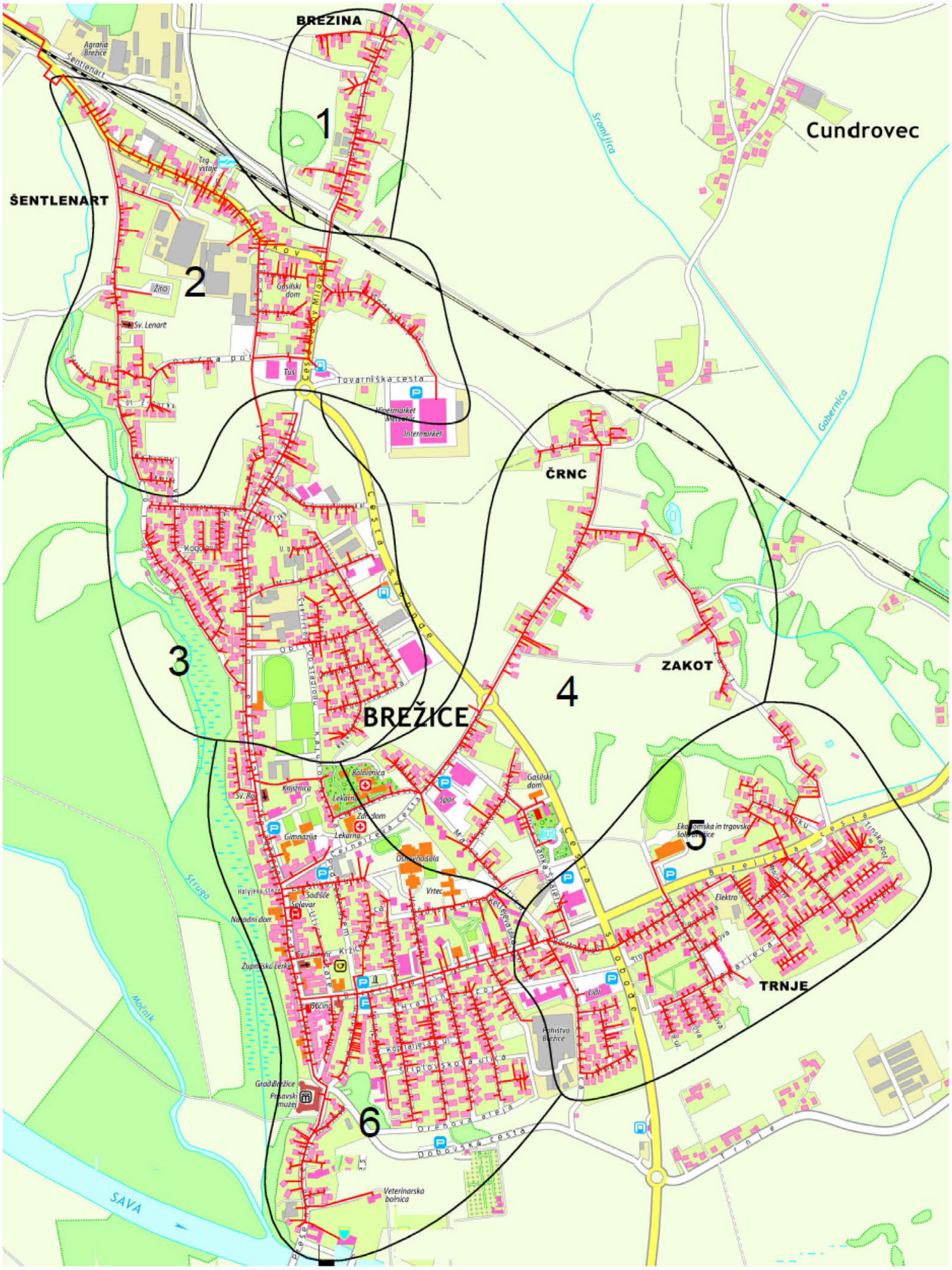
Two temperature regimes were analysed, at 90°C/60°C and 120°C/60°C. The analysis showed that the regime of 120°C/60°C is more appropriate, mainly due to smaller pipes (lower costs) needed for the same amount of transferred heat energy.

Figure 6.8: **District heating system in Krško**



Source: GEN Energija (2013).

Figure 6.9: **District heating system in Brežice**



Source: GEN Energija (2013).

- Possible heat sources in NEK for the district heating system

The study conducted by SIPRO Engineering (SIPRO Engineering, 2013) analysed several alternative heat generating sources for the district heating supply (e.g. nuclear power plant cogeneration, heat pumps on tertiary system, wood and gas). The analysis showed that the most prominent solution is heat utilisation from NEK. Regarding heat consumption, the district heating of the Krško and Brežice area is a relatively small system, yet with a rather largely branched distribution system. A favourable price of heat from NEK represents one of the main advantages of the planned district heating system.

The heat source power required for heating in the area of Krško and Brežice was estimated at approximately 70 MW. The average annual load of the district heating system amounts to 18.5 MW. The heat sources that can ensure enough heat supply for the district heating or other purposes from NEK are:

- steam extraction from the secondary circuit; and
- waste heat from the tertiary circuit at the condenser outlet.

The first case involves heat extraction from the turbine steam for somewhat reduced electricity generation. The second case involves the use of the heat potential of low-temperature water leaving the system after condensation. The utilisation of waste heat from the tertiary circuit at the NEK condenser outlet was identified as one of the most attractive technical solutions of the heat source supplying the district heating system since it does not interfere with the operation of NEK. A combination of two stage heat pumps as well as wood biomass boilers was foreseen to heat up the water to the higher temperatures. Based on a rough comparison of the results obtained in the basic study (SIPRO Engineering, 2013), it has been concluded that the solution of heat pumps is economically less suitable than steam extraction from NEK.

In the secondary circuit of NEK, five extraction points have been identified as potential connection points (Figure 6.9):

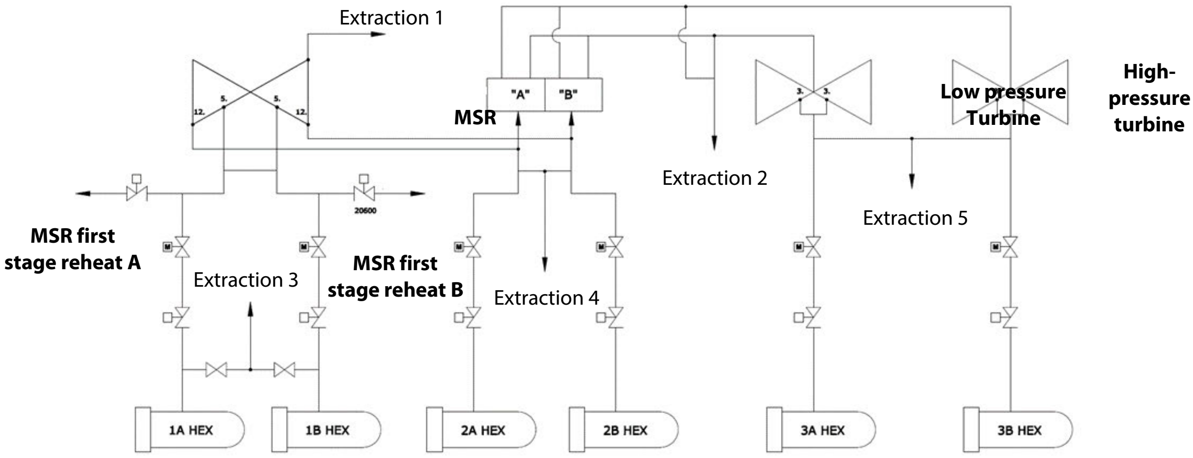
- Extraction 1: Replacement of the high-pressure turbine (planned modification in NEK);
- Extraction 2: Extraction point between the moisture separator reheater and low-pressure turbine;
- Extraction 3: Steam extraction from an existing high-pressure turbine line (EX system);
- Extraction 4: Steam extraction on the cross connection of the steam lines for the regenerative heaters 2A and 2B;
- Extraction 5: Steam extraction from the low-pressure turbine.

Steam extraction in NEK represents the most suitable and verified heat source of the planned district heating system (Figure 6.10). The most appropriate connection point would be Extraction 4 (9.6 bar, 178°C), where the reduction in electrical energy due to less available steam in the turbines is the lowest. It is positioned at the outlet of the steam pipe from the high-pressure turbine on the so-called cross connection before entering to the moisture separator reheater. The maximal steam extraction at this point required for the district heating system amounts to 128 t/h (at 70 MW of source thermal power, it amounts to 112 t/h), and the average one to 29.5 t/h. The required annual quantity of steam at the extraction point corresponding to approximately 123 000 MWh/year of the supplied heat amounts to 215 129 t. The reduction in electrical power output at 70 MW thermal power of the source amounts to 14.9 MW_e, while the average reduction at 18.5 MW thermal power amounts to 3.93 MW_e. Figure 6.10 shows different analysed heat sources.

Besides the extractions on the high-pressure part of the turbine, the possibility of steam extraction from the low-pressure part of the turbine was analysed as well. At this stage, and based on available data, it was concluded that this possibility is less favourable.

District heating for the Krško and Brežice area is reasonable only in case of a prolongation in the nuclear power plant's lifetime. After the year 2043, the heat source in NEK would be substituted by the heat generated in the planned Krško 2 Nuclear Power Plant.

Figure 6.10: **Different extraction points**



Source: GEN Energija (2013).

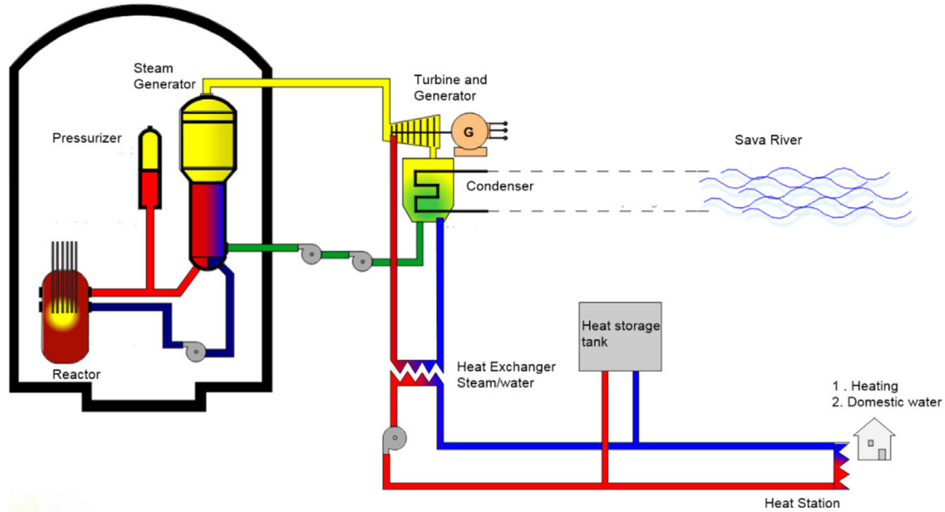
- Backup systems for heat supply

Several options for backup systems were also considered to ensure a replacement of the main heat source in the district heating system in case of planned/unplanned shutdown of NEK:

- existing boiler houses in Krško and Brežice (over 40 MW heat) – Backup 1;
- existing Gas Power Plant Brestanica (TEB) – Backup 2;
- existing heat system in the factory Vipap (66 MW) – Backup 3;
- gas boiler (40 MW) – Backup 4;
- electric heater (40 MW) – Backup 5.

The analysis showed that the most appropriate solution is the existing boiler houses in Krško and Brežice, which would be primarily used as a replacement of the heat source in NEK. These boiler houses can ensure 40 MW_t of thermal power. In order to meet the maximal demand of up to 70 MW_t an additional gas boiler house of 30 MW_t is foreseen.

Figure 6.11: **Schematic positioning of heat storage tank**



Source: GEN Energija (2013).

A heat storage tank of approximately 260 MWh_t capacity and a volume of 6 900 m^3 is foreseen as well. A heat storage tank might not be necessary to provide a continuous transition from the basic source to the replacement heat sources, but it enables a more optimal operation in terms of heat and electricity generation and it balances oscillations and transients.

- Steam production for industry

As mentioned in the previous section, potential industrial steam consumers are the nearby companies Vipap and Krka. The companies have different process requirements for steam, as shown in Table 6.4.

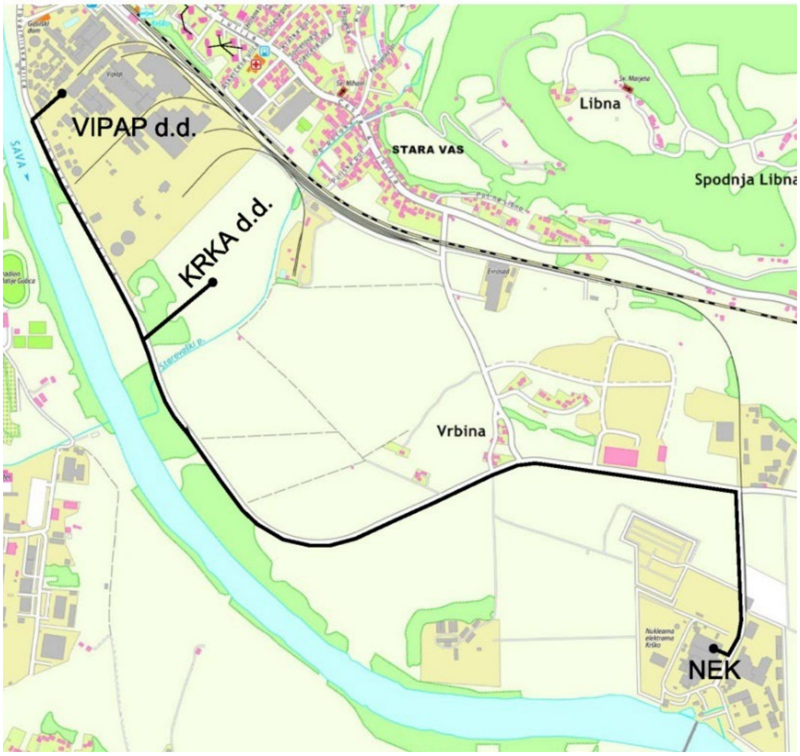
Table 6.4: **Steam capacity requirements in nearby industrial facilities**

Industrial consumers	Parameters		
	Pressure (bar)	Temperature (°C)	Steam flow (t/h)
Krka	12 bar (abs)	188	16
Vipap and Krka	4.6 bar (abs)	190	60

Source: GEN Energija (2013).

In line with different requirements as regards to the steam parameters, two separate distribution systems from NEK are foreseen. The distance between the steam generators in NEK and both industrial consumers (Vipap and Krka) is approximately 3.5 km. The aboveground pipelines are routed as shown in Figure 6.12.

Figure 6.12: **A schematic display of the foreseen steam distribution system for industrial consumers Vipap and Krka**



Source: GEN Energija (2013).

- Distribution of 12 bar (abs), 188°C steam for Krka

In NEK, a new industrial steam (steam/steam) generator of 12 MW thermal power will be installed. The heat source applied will be steam from Extraction point 3 (Figure 6.10) with capacity of 17.5 t/h. Steam generated in the steam generator will be distributed along a DN 150 steam pipeline to the consumer, Krka. The sub-cooled condensate of around 60°C shall be supplied into a condensate tank located in the close vicinity of the consumer, and further on, by feed pumps, via a DN 50 pipeline back to the industrial steam generator in NEK. At the consumer's location, the steam shall be compressed to a required pressure of 12 bar (abs). The circulating pump power shall be 15 kW. The Krka plant's anticipated annual consumption of steam at a higher pressure in the final construction phase will be 131 000 t.

Table 6.5: **Characteristics of 12 bar distribution to Krka**

Parameter:	Value:
Pressure	12 bar (abs)
Temperature	188°C
Power of industrial steam generator	12 MW
Capacity	17.5 t/h
Heat source	Extraction 3
Temperature of condensate	60°C
Circulating pump power	15 kW
Estimated annual consumption	131 000 t

Source: GEN Energija (2013).

- Distribution of 4.6 bar (abs), 190°C steam for Vipap and Krka

In NEK, an additional new industrial steam (steam/steam) generator of 44 MW thermal power shall be installed. The heat source applied shall be steam from Extraction point 3 (Figure 6.10), with capacity of 67 t/h. Steam generated in this steam generator shall be then distributed along a DN 450 steam line to the consumers Vipap and Krka. The sub-cooled condensate of around 60°C shall be supplied into (a) condensate tank(s) located in the close vicinity of the consumers and further on, by feed pumps, via a DN 100 pipeline back to the industrial steam generator in NEK. It is assumed that the consumer would take care of replacing the lost medium. At the individual consumer's location, the steam shall be compressed to a required pressure of 4.6 or 4 bar (abs), respectively. The circulating pump power shall be 35 kW. The Krka and Vipap plants' anticipated annual consumption of steam at a lower pressure in the final construction phase will be 510 000 t.

Table 6.6: **Characteristics of 4.6 bar distribution to Krka and Vipap**

Parameter:	Value:
Pressure	4.6 bar (abs)
Temperature	190°C
Power of industrial steam generator	44 MW
Capacity	67 t/h
Heat source	Extraction 3
Temperature of condensate	60°C
Circulating pump power	35 kW
Estimated annual consumption	510 000 t

Source: GEN Energija (2013).

In case the basic source is unavailable (e.g. due to a forced outage of NEK or during a NEK overhaul) the potential industrial steam consumers Vipap and Krka will use their own capacities as the replacement source.

6.3.4. *Economic analysis*

Three variants were analysed. Variant 1 and 2 are possible alternatives to the district heating system, whereas variant 3 is a distribution system for industrial steam supply.

- variant 1 – steam extraction from the secondary circuit;
- variant 2 – waste heat from the tertiary circuit with reheating provided by heat pumps and biomass boilers; and
- variant 3 – industrial steam supply.

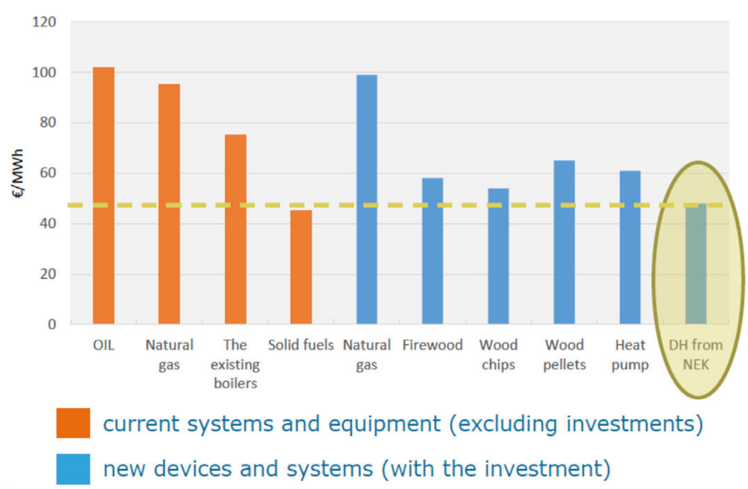
The economic analysis was based on the provisions of the Energy Act and the Regulation on the Formation of Prices for Production and Distribution of Steam and Hot Water in the District Heating System for Tariff Users (Government of the Republic of Slovenia, 2014). For tariff users, the price of heat is regulated by the Energy Act EZ-1 and the Regulation on the Formation of Prices for Production and Distribution of Steam and Hot Water in the District Heating System for Tariff Users. According to this regulation, the price is defined by the level of justified expenses. The price may also include profits, which are however intended only for legal and statutory reserves of the distributor and are therefore not available for payments to the owners (return on owner equity).

A sensitivity analysis was also performed to monitor how modified input data affect average heat costs. In the analysis, the following were varied:

- the investment costs (from +40% to -40%);
- size of production and seals of heat (from +40% to -40%); and
- purchase steam price (from +40% to -40%).

Different technologies for heating are used in the area of Krško and Brežice. Based on available data from Local Energy Concepts, in the area of Krško the predominantly used technologies are based on natural gas (45%), followed by solid fuels (34%) and oil (18%). In the area of Brežice the prevailing technologies are based on oil (38%), solid fuel (36%) and natural gas (23%). The remaining 3% covers the use of other technologies mainly based on electricity.

Figure 6.13: **Prices for individual heating systems in the area of Krško and Brežice compared to the district heating system from NEK (variant 1)**



Source: GEN Energija (2013).

The most competitive and attractive variant for district heating is the district heating system (DH) from NEK (variant 1) with a price set at around EUR 49/MWh, including the investment costs in the distribution system. This assumption was made considering the existing system based on solid fuel systems, which have already depreciated.

The price of heat for the variant 2 (heat from the tertiary circuit with reheating provided by heat pumps and biomass boilers) is approximately EUR 64/MWh, and is thus competitive only for consumers using gas or oil and consumers using heat from the existing boiler houses.

In light of the analysis made and an average Slovenian price of heat around EUR 65.5/MWh, it is clear that the price of heat in the Krško-Brežice distribution system would be favourable.

Even though the selling price of heat is regulated by law and does not allow investors to make profits, this does not mean that the investment in general does not generate financial benefits. In the case of regulated heat prices, the majority of financial benefits go to the consumers, whereas the community as a whole enjoys the environmental and social benefits.

The systems for steam supply to the industrial facilities in the vicinity of NEK were also analysed. The selling price for steam for industrial users is not regulated as in the case of district heating, but is a matter of negotiation between the seller and the buyer. In any case, it should be a win-win situation. Thus, from the investor point of view, supplying steam to the industrial facilities could be the main reason to invest capital into the project (district heating and industrial steam).

6.3.5. *Impacts on the environment*

The introduction of a district heating system whereby the heat source is steam generated in NEK would undeniably improve air quality in the area of Krško and Brežice as well as reduce greenhouse gases emissions.

Table 6.7 shows different environmental impacts for two variants:

- variant 1 – steam extraction from the secondary circuit of NEK;
- variant 2 – waste heat from the tertiary circuit with reheating provided by heat pumps and biomass boilers.

Table 6.7: **Different environmental impacts of the variant 1 and 2**

Environmental impacts	Variant 1: steam extraction from the secondary circuit	Variant 2: waste heat from the tertiary circuit
Area occupancy	Compact	Moderate
Degradation of the area	Moderate	Moderate
Noise during operation	Low level	Moderate level
Noise during construction	Moderate level	Moderate level
Air emissions	Practically no emissions	Minimal emissions
Releases into water sources	Practically no releases	Minimal releases
Usage of water sources	Minimal usage	Minimal usage
Greenhouse gases	Without	Without
Flora	Minimal	Minimal
Fauna	Minimal	Minimal
Electromagnetic influence	Minimal	Low

Source: GEN Energija (2013).

6.3.6. *Summary*

A cogeneration system in NEK can represent a broad range of new business opportunities for the local environment. District heating is something that NEK can provide to the nearby community. Besides the obvious financial benefits for the users, it can offer a significant contribution to making the environment cleaner and more friendly, with less CO_2 and other emissions. The heat from NEK can also be used for other purposes. The most promising is the production of steam for industrial needs where the price for steam in current industrial facilities can be significantly reduced. A competitive price for industrial steam can also be a good reason for any newcomers, who could decrease their energy costs and thus become more competitive on the global market. At the same time, new factories can offer many new jobs to the local community and contribute to social welfare.

Other options of heat use were also analysed. From the technical and environmental points of view, heat can be used for cooling in absorption chillers and thus cooling in all kinds of buildings. However, the concentration of the users in this case is too low for this to be economic. Agriculture is another sector where low-temperature heat could be used. In this case it is not economically feasible because the bigger agricultural sites are too far from NEK. However, it might be a viable opportunity for any new greenhouses set up in the vicinity of NEK.

Combining electricity generation and utilisation of heat for district heating, industrial steam, and/or other options is a key way to increase the total efficiency and income of the plant. Expanding the business model of the plant in a sustainable way at a time when the electricity market conditions are difficult for big traditional plants, including nuclear power plants, is just an additional privilege that needs to be seriously considered for existing and new nuclear power plants.

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6.4. Cogeneration at the Beznau Nuclear Power Plant, Switzerland

6.4.1. *Nuclear power in Switzerland*

Switzerland has a population of nearly 8.1 million people distributed over an area of 16 000 m^2. Electrical consumption corresponds to 60 TWh, with nuclear energy accounting for 41% of the total. The five nuclear power reactors are situated at four locations. The Leibstadt KKL Nuclear Power Plant (GE, BWR 6 Mark III, December 1984) is the largest station in the country with an electrical output of 1 280 MWe. The two units of the nearby located power plant Beznau KKB I&II (Westinghouse, PWR 2 Loop 2 x 365 MWe, September 1969/December 1971) are, like the KKL, also situated in the canton Aargau. The pressurised water reactor Gösgen KKG (Siemens-KWU, PWR 985 MWe), located on the Aare River in the canton of Solothurn, was put into operation in 1979. The Mühleberg KKM Nuclear Power Plant (GE, BWR 4/Mark I 373 MWe, November 1971) will operate until the end of 2019, after which it will be decommissioned.

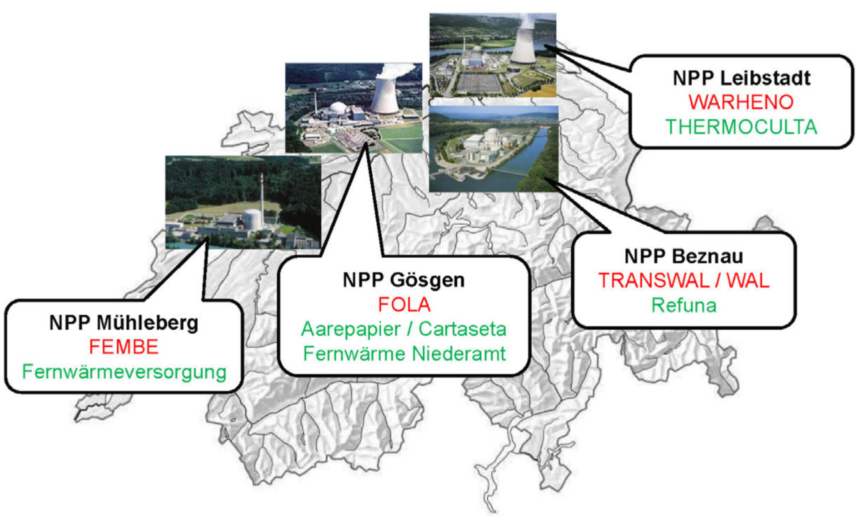
Figure 6.14: **Nuclear power plants in Switzerland**

Source: Nuklearforum Schweiz (2007).

6.4.2. *Cogeneration in Switzerland*

The first work on using thermal energy from energy and waste disposal plants for district heating and process steam began at the end of 1970s and beginning of 1980s. The cogeneration networks in Switzerland were mostly established at this time because the oil crisis forced the government and utilities to find new and sustainable solutions for energy supply to be more independent from fossil fuels like oil or natural gas. Projects were developed to use the principle of cogeneration in the nuclear power plants to extract process steam. Due to economic assessments of the projects and changes in the overall market situation for fossil fuels, not all projects were realised. Figure 6.15 shows an overview of the cogeneration projects at nuclear power plants in Switzerland that were realised or planned.

Figure 6.15: **Cogeneration at nuclear power plants in Switzerland**



Source: Nuklearforum Schweiz (2017).

Every Swiss nuclear power plant possesses a cogeneration application. The demand for output varies from 2 MWth to 80 MWth. The steam extraction is used either for district heating or process steam for industrial purpose. The largest cogeneration network, called “Refuna”, which means “Regional district heating lower Aare valley”, is supplied with thermal energy from the Beznau Nuclear Power Plant.

6.4.3. *Steam extraction from the Beznau Nuclear Power Plant*

The Refuna district heating grid supplies over 20 000 people in 11 communities with thermal energy (Graf, 2004). The maximum connection load is specified to 80 MWth. The Paul Scherrer institute (PSI), the largest research centre for natural and engineering sciences in Switzerland, was connected to the district heating network in the winter of 1983/84. The grid connection to costumers began one year later.

The district heating network consists of 31 km of main pipes and 103 different customer pipelines, which add up to a total of 290 km worth of pipelines (Refuna AG, 2015a).

Figure 6.16: **District heating network at the Beznau Nuclear Power Plant**

Source: REFUNA AG (2015b).

Legend translation: heisser Vorlauf und = hot water flow; ausgekühlter Rücklauf = cold water flow (return); Reserveheizwerk = reserve heating plant; Druckerhöhungsstation = station to increase pressure; Wärmeübergabestation = heat transfer station.

The heat extraction is located between the high-pressure and low-pressure turbine. The steam is extracted at 127°C to the heat exchanger. After that, the thermal energy is transported to the district heating system, where the water in the pipes is warmed up to 120°C. Each of the two units of the Beznau Nuclear Power Plant can be used for heat extraction. The Beznau Nuclear Power Plant can supply the district heating network Refuna with thermal energy over the whole year, 24 hours a day, even during an outage of a single unit. The electrical output of the plant is reduced by 7.5 MWe during maximum heat extraction (Axpo AG, 2016).

6.4.4. *Economical consideration*

General assessment

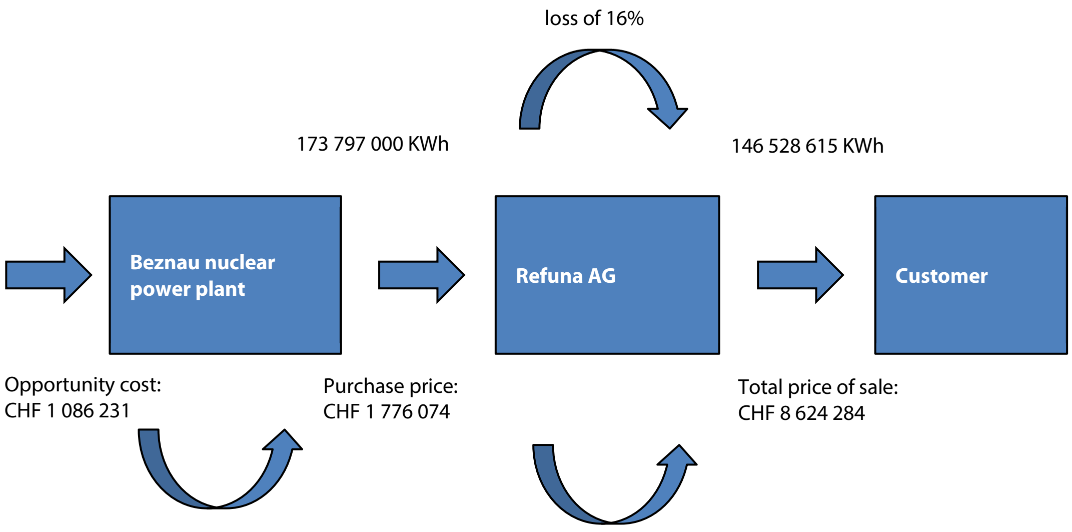
The decision to extract steam from the Beznau Nuclear Power Plant and provide the Refuna district heating network with thermal energy was mainly based on political and ecological decisions due to the oil crisis in the 1970s and 1980s. The application was not intended to be used for commercial purpose as a replacement for electrical energy production. Instead, the cogeneration was viewed as an opportunity to increase the flexibility of the nuclear power plant amid changes in the energy and oil market.

The economic analysis of the heat extraction can be done through an assessment of the opportunity costs of power plant operators and district heating network operators. In the case of the Beznau Nuclear Power Plant, the typical opportunity cost of power plant operators can be described as follows:

- Market price electricity CHF 41.55/MWhe
  (weighted average market price in Switzerland 2015 [BFE, 2016])
- Lost electricity production 1 KWhe/8 kWhth
  (typical for the situation of the Beznau Nuclear Power Plant [Schmidiger, 2013])
- Calculated opportunity costs for heat 6.25E-3 CHF/KWhth
  (without taking capital costs or operation and maintenance costs into account)

The Beznau Nuclear Power Plant delivered approximately 173 800 000 KWhth district heating to Refuna in the business year 2014/15 (Refuna AG, 2015a). Hence the annual opportunity costs add up to CHF 1 086 231. Refuna payed CHF 1 776 074 for this amount of thermal energy (Refuna AG, 2015a). The purchase price is to some extent coupled to the market price of oil.

Figure 6.17: **Economic flow chart business year 2014/15**

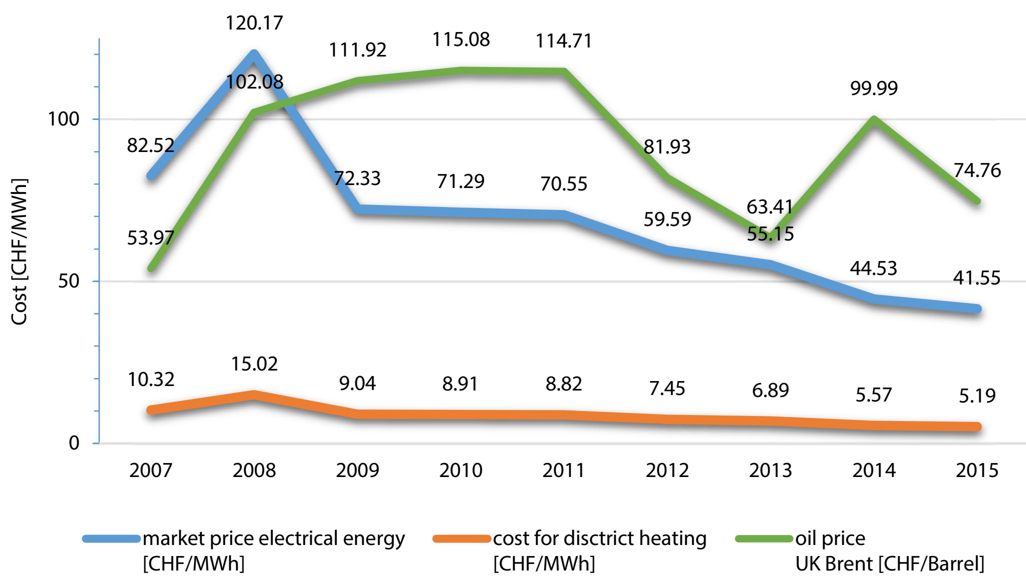


Source: Asser (2017).

Refuna could obtain total sales of CHF 8 624 284 for purchasing 146 528 615 KWhth of district heating in the business year 2014/15 (Refuna AG, 2015a). The loss of nearly 16% of the thermal energy is caused by heat transfer.

The market price for electrical energy in Switzerland declined by 65% from 2007 to 2015. The maximum of CHF 120/MWh was reached in the year 2008 (BFE, 2016). By comparison, in the year 2015 the average market price was CHF 42/MWh (BFE, 2016). The market price for oil has declined over 40% in the last five years. By May 2016 the oil price was at CHF 45/barrel (OPEC and IEA, 2016). The opportunity cost of district heating for the Beznau Nuclear Power Plant has evolved similarly, as shown in Figure 6.18.

Figure 6.18: **Comparison of oil and electrical power price with opportunity cost for district heating**



Source: Asser (2017).

Distributor expenses

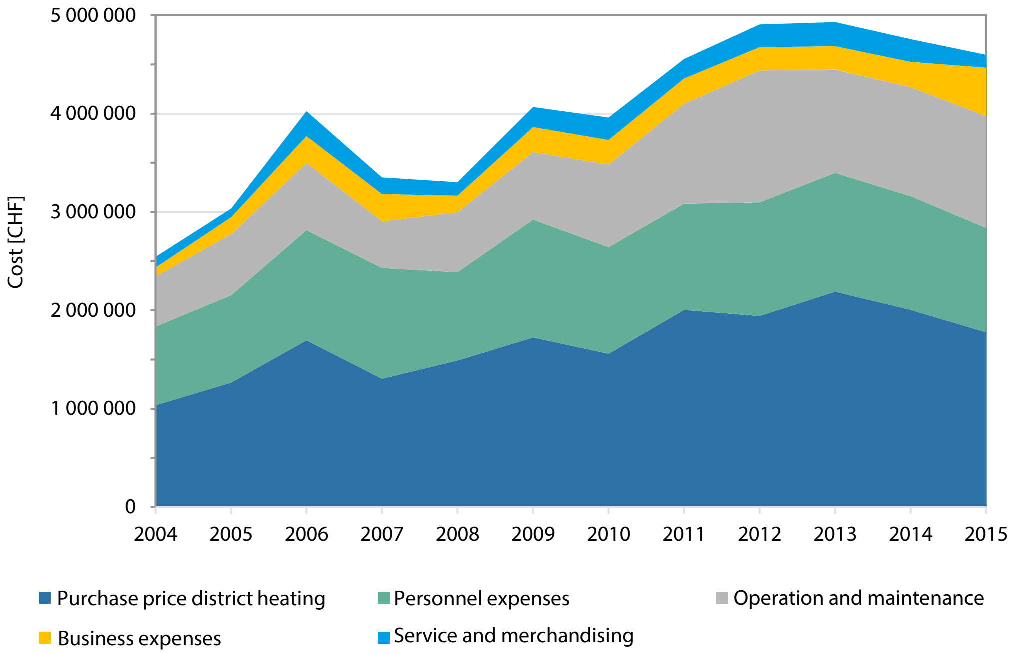
The additional costs for the distributor Refuna AG, beside the expenses for purchasing district heat from the Beznau Nuclear Power Plant, comprise:

- operation and maintenance;
- business administration;
- personnel;
- service and merchandising.

The expenses for operation and maintenance include the costs for the required material and external personnel. The grid system, with its total length of nearly 300 km, was installed in the 1990s. In particular, the maintenance of the buried pipes, pumps and valves, which have been in operation for over 40 years, leads to a rise in costs. The supply to the customer must be sustained while outages of pipeline sections take place, so backup heating plants that run with fossil fuels or waste may be needed. Most of the maintenance work can be done in the warm summer months because at this time the district heating is only used for warm water production.

The following chart shows the development of costs for the district heating distributor Refuna AG over the last ten years.

Figure 6.19: **Development of distributor expenses**



Source: Asser (2017).

Overview of customer expenses

The costumer expenses include a nonrecurring charge for the grid connection, depending on the connection power, the investment for the district heating equipment, possible maintenance costs and the regular heating costs, which consist of a basic price and the amount of received thermal energy multiplied by the calculated thermal price.

The price for the equipment, including heating station, boiler, heat exchanger, pumps, surveillance, and measurement tools, and the commissioning is CHF 11 320 (Refuna AG, 2016).

In addition to the nonrecurring charge, there is a fee on the connection to the district heating network which consists of a package price. The package price can be calculated with the formula (Refuna AG, 2006):

$$A = 200 * P^{0.7}$$

$$A \equiv package\ price\ [CHF]$$

$$P \equiv connection\ power\ [KW]$$

The distributor clears the costs for the construction of the house connection to the district heating network with an additional fee.

Comparison of buildings

The calculation of the regular heating costs could be conducted using the specific annual heat consumption per energy reference area.

Table 6.8: **Equation quantities related to age of buildings**

Equation quantity to age of building	Unit	old < 1970	new > 1998	Minergie
Specific heating power per area energy reference level (EBF)	W/m^2	70	30	15
Annual specific heating consumption per area energy reference level (EBF)	kWh/m^{2}a	200	100	40
Annual specific heating consumption per area energy reference level (EBF) without warm water	kWh/m^{2}a	160	70	20

Source: Gloor (2013).

For further calculations it is necessary to define a specific energy reference area (EBF). The EBF represents the summary of all ground areas of one building that are heated or cooled. The calculation can be done by the following formula:

$$E_{th} = C_{EBF} * EBF$$

$$E_{th} \equiv \textit{Annual thermal energy consumption } [KWh/a]$$

$$EBF \equiv \textit{Specific energy reference area } [m^2]$$

$$C_{EBF} \equiv \textit{Annual specific heating consumption per area EBF } [KWh/m^2a]$$

The specific heating price in 2015 was set by contract at 5.6 Rp[2]/KWh$_{th}$ (Refuna AG, 2015b). The estimated heating hours in that year were 2 200 h/a (Nussbaumer, 2005). If the annual thermal energy consumption is multiplied with the specific heating price, the annual heating price is obtained. In addition to the heating cost, the annual basic price, which depends on the required connection power, has to be paid.

The required connection power indicates an estimated value for the thermal power extraction from the district heating network. It can be obtained as follows:

$$P_{th} = E_{th} \div T_{th}$$

$$P_{th} \equiv \textit{Required connection power } [KW]$$

$$T_{th} \equiv \textit{Annual heating hours } [h/a]$$

The annual basic price can be extracted from a price data sheet in consideration of the required connection power (Refuna AG, 2015b). If the basic price is added to the heating cost, the estimated heating price for one year is obtained.

Table 6.9 shows the results of calculations for different examples of buildings in Switzerland with the assumed EBF of 200 m^2 and 600 m^2 and different ages.

2. Equivalency in Euro/Eurocents: 1 Rp = 0.9 Eurocent / CHF 1 = EUR 0.9 (based on the exchange rate of June 2016).

Table 6.9: **Calculation of total annual heating cost**

Type of house (warm water and heating)	Unit	2010 Minergie	1990 House	1970 House	1990 Office
EBF (approval)	[m^2]	200	200	200	600
Thermal energy consumption	[KWh/a]	8 000	20 000	40 000	60 000
Annual heating cost	[CHF/a]	448	1 120	2 240	3 360
Required connection power	[KW]	3.64	9.09	18.18	27.27
Annual basic price	[CHF/a]	319	446	877	1 170
Total cost per year	[CHF/a]	767	1 566	3 117	4 530

Source: Asser (2017).

Market analysis

The oil price in Switzerland reached its highest level in 2008 with an average value of CHF 150 per 100 l of fuel oil. The price then dropped to CHF 70 per 100 l of fuel oil by 2016 (Heizöl24, n.d.). The gas price is partly coupled to the oil price and also dropped to a similarly low level in 2016. The slump of the market prices for fossil fuels challenged the competitiveness of district heating

The actual market prices for alternative energy sources were:

- diesel oil (2016) CHF 70/100 l;
- diesel oil (2008) CHF 150/100 l;
- wood pellets (2016) CHF 370/1 000 kg;
- natural gas (2016) CHF 0.085-0.1/KWh.

The equivalent heating costs can be calculated taking into account the specific heating value of the energy sources as shown in the following table (Beuth, 2013).

Table 6.10: **Market analysis thermal energy sources**

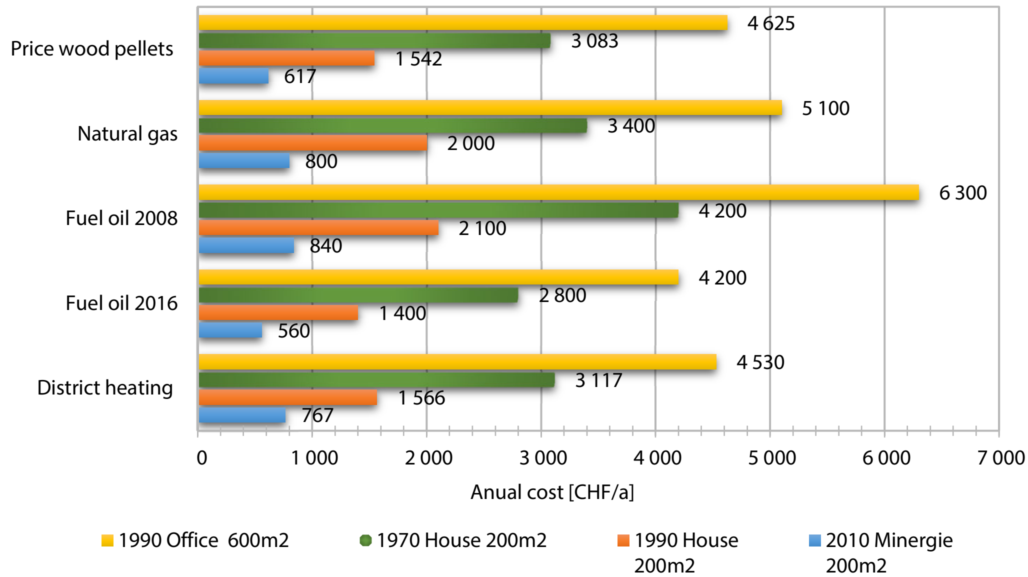
Type of house (warm water and heating)	Unit	2010 Minergie	1990 House	1970 House	1990 Office
EBF (approval)	[m^2]	200	200	200	600
Thermal energy consumption	[KWh/a]	8 000	20 000	40 000	60 000
Total cost for district heating	[CHF/a]	767	1 566	3 117	4 530
Amount diesel oil equivalent	[l]	800	2 000	4 000	6 000
Fuel oil price 2016	[CHF/a]	560	1 400	2 800	4 200
Fuel oil price 2008	[CHF/a]	840	2 100	4 200	6 300
Gas price per energy consumption	[CHF/KWh]	0.1	0.1	0.085	0.085
Natural gas price	[CHF/a]	800	2 000	3 400	5 100
Amount wood pellets equivalent	[kg]	1 667	4 167	8 333	12 500
Price for wood pellets	[CHF/a]	617	1 542	3 083	4 625

Source: Asser (2017).

The estimated amount of diesel oil and wood pellets can be calculated by dividing the values of the thermal energy consumption by the specific heating value. The price in Switzerland for natural gas received from local supply networks is contractually stipulated to be similar to district heating applications. The gas price level per energy consumption is adopted for the region of Baden, which is the nearest city to the Beznau Nuclear Power Plant with a connection to a gas network.

The calculated amounts of the alternative energy sources in connection with the actual market prices lead to the estimated heating price per year, which is shown in the next chart.

Figure 6.20: **Comparison annual heating costs**



Source: Asser (2017).

The diagram illustrates that the annual costs for district heating are on a similar level to those of fuel oil, natural gas or wood pellets. Using the oil price of 2008, district heating provides 30% lower costs per year. Moreover, the equipment and maintenance costs for oil heating systems (additional tank room, periodic outage of the tank, etc.) or wood-pellet heating systems (combustion, ash disposal, etc.) are significantly higher. In summary, an economic comparison with fossil and renewable fuels shows that district heating still is competitive.

Consumer acceptance

The end costumers of the district heating are mostly nearby communities around the Beznau Nuclear Power Plant. The district heating provides over 15 000 people with thermal energy for heating or warm water production. In addition to an appropriate cost-benefit situation, the public acceptance depends mostly on the following factors (in order of importance):

- high availability;
- usability/applicability; and
- sustainability.

The cogeneration from the Beznau Nuclear Power Plant has been continuously available since commissioning in the 1980s. There exist five backup heating plants that can be used if unscheduled outages affect both units of the Beznau Nuclear Power Plant at the same time. Hence there is only an insignificant probability that a situation could occur which would lead to an interruption of thermal power supply.

It is also important for end costumers that the installation and use of the equipment is as simple as possible. The connection to the district heating grid and the implementation of the equipment is carried out by a craftsman employed by the distributor. Furthermore, scheduled maintenance work, like the inspection of the boiler or the heat exchanger, is regular. There is no additional maintenance work, like cleaning or inspecting tanks, that has to be done, for example, for oil heating systems. The district heating system represents a user-friendly opportunity for heating and warm water production.

A sustainable energy system covers current energy demand without compromising the energy supply of upcoming generations and without jeopardising the environment. One important factor to consider when assessing the sustainability of energy systems is the emission of greenhouse gases. The total greenhouse gas emissions (GHG) of the cogeneration system of the Beznau Nuclear Power Plant and its district heating add up to 0.013-0.019 kg CO_2-equiv./KWh (Hirschberg, 2015). Other combustion processes that can be used to heat up water to a temperature of 120°C have significantly higher values. Connecting steam extraction from the nuclear power plant and supplying warm water through heat exchangers are ecologically beneficial solutions for thermal energy supply.

The annual thermal power of Refuna of approximately 150 000 MWh is comparable to:

- 15 000 t of heating oil (heat value 10 MWh/t = 750 lorries * 20 t);
- 30 000 t of wood pellets (heat value 5 MWh/t = 1 500 lorries * 20 t);
- 210 000 Sm^3 of woodchips (heat value 0.7 MWh/Sm^3 = 5 250 lorries * 40 m^3).

Conclusion

The cogeneration application at the Beznau Nuclear Power Plant has provided 15 000 people with thermal power continuously for more than 30 years. The economic assessment shows that steam extraction from a nuclear power plant could be a beneficial alternative in the context of decreasing market prices for electrical energy, especially if there is flexibility to react to changes in the energy market rate. The district heating network Refuna represents a competitive approach compared to fossil fuel-based solutions, even with depressed fuel oil and natural gas market prices. Moreover, a district heating network provided by steam from a nuclear power plant could represent a sustainable and reliable solution, contributing to efforts to avoid GHG emissions and mitigate global warming.

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6.5. **Nuclear energy for oil sands in Canada**

6.5.1. ***Introduction***

Use of nuclear energy for the extraction of bitumen from oil sands has been studied extensively over the past two decades. Bitumen extraction is an energy-intensive process that uses natural gas, and thus contributes significantly to greenhouse gas (GHG) emissions. The two main considerations for use of nuclear energy for oil sands operations have been security of energy supply and reductions in GHG emissions. This chapter summarises the current status and the studies carried out to date.

Oil sands are a natural mixture of sand, water, clay and a type of heavy oil called "bitumen". Bitumen must be removed from the sand and water before being upgraded into crude oil and other petroleum products. In Canada, the province of Alberta has proven oil reserves of 170 billion barrels, consisting of bitumen (about 168 billion barrels) and conventional crude oil (1.7 billion barrels). It represents the third largest proven reserves of oil in the world. Oil sands are located in three major areas in northeast Alberta underlying more than 140 000 square kilometres. In addition, there are unexploited reserves in the neighbouring province of Saskatchewan.

There are two methods of extracting bitumen from the oil sands: open-pit mining and in situ extraction. Bitumen that is close to the surface is mined. Bitumen that is deep within the ground is produced in situ using specialised extraction techniques. Open-pit mining extracts oil sands that are less than 75 metres deep; in situ technologies are applied to extract bitumen from deeper deposits. Less than 5% of the oil sand reserves are accessible by surface mining. The mined product is upgraded to synthetic crude oil. Bitumen recovered in situ is usually mixed with a lighter material to allow it to be shipped for processing at other locations. The bitumen shipped via pipeline is either sent directly to markets across Canada and the United States for upgrading or to Edmonton for upgrading and then shipped as synthetic crude oil. Synthetic crude oil is also refined in Edmonton and made into marketable products like fuel oil, gasoline, ethylene and propylene. Most in situ operations use the steam-assisted gravity drainage, or SAGD, process. This method involves pumping steam underground through a horizontal well to liquefy the bitumen that is then pumped to the surface through a second well. In 2018, Canada's production of bitumen averaged 2.99 million barrels per day; about 82% was produced in the province of Alberta (Natural Resources Canada, 2019). About 50% of the oil sands production is through in situ techniques. Alberta's oil sands produce about 1.57 million barrels per day (~250 000 m^3/d) through in situ techniques (Alberta Energy Regulator, 2019).

Upgrading bitumen to synthetic crude oil uses catalysts to crack the big molecules into smaller ones at high temperatures and pressures. Adding hydrogen or removing carbon from the oil creates hydrocarbon molecules like those in light oil. Upgraded oil replaces conventional crude oil to make gasoline, diesel, jet fuel and heating oil.

Upgrading is usually a two-stage process (Canadian Association of Petroleum Producers, 2015):

- Coking or hydrocracking – used to break up the molecules. Coking removes the carbon, while hydrocracking adds hydrogen.
- Hydrotreating – used to stabilise the oil and remove impurities such as sulphur.

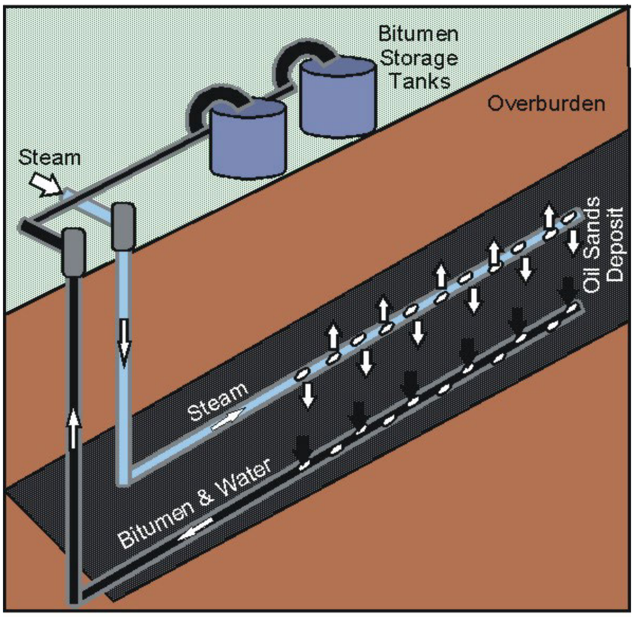
In 2020, about 46% of Canada's bitumen from oil sands is upgraded locally (Natural Resources Canada, 2020). Canada's capacity for upgrading of bitumen is 1.33 million barrels per day. Bitumen can also be diluted with petroleum condensates and directly sold to the petroleum refineries capable of processing heavier crudes.

6.5.2. ***Energy and utilities requirements***

Extraction of bitumen from oil sands

The SAGD process consists of placing a long horizontal production well near the base of the reservoir and placing a steam injection well parallel to and approximately five metres above the production well, as illustrated in Figure 6.21. Communication is established between the injector and the producer by circulating steam in both the injector and the producer (Donnelly and Pendergast, 1999). The reservoir between the two wells is heated by conduction. Once heated, the bitumen flows and communication between the wells is possible. Once the communication is established, because of its low density, the gaseous steam rises in the reservoir from the injection well and heats the formation. The heated oil and water (both condensed steam and heated formation water) in the formation drain down to the horizontal production well from which they flow to surface. As the oil and water is withdrawn from the reservoir, the steam chamber expands both upwards and sideways. The upward growth proceeds in a random but rapid manner until it is limited by the top of the reservoir. In contrast, the steam chamber expands sideways and downwards in a very stable manner. At a later stage in the process, when the chamber has reached the top of the reservoir, the rate of oil production is controlled by the lateral expansion of the steam chamber. During this phase of the process, the production rate will decline and the steam-oil ratio (SOR) will eventually increase because of heat losses to the overburden. SOR is a measure of the amount of steam required, in terms of cold-water equivalent, to produce a barrel of oil. About 87% of the water used for SAGD process is recycled. Advances in technology, such as directional drilling, enable in situ operations to drill multiple wells (sometimes more than 20) from a single location, further reducing the surface disturbance. SAGD projects are typically implemented in stages, starting as low as 5 000 barrels per day and growing up to 200 000 barrels per day at peak capacity.

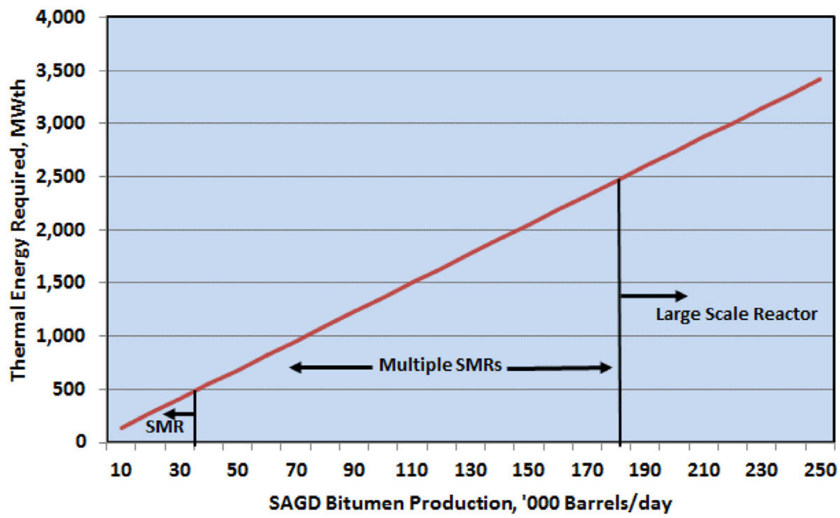
Figure 6.21: **Steam-assisted gravity drainage process**



Source: Axpo AG (2016).

SAGD is an energy-intensive process, requiring the equivalent of 20% of the energy in the oil. The steam is produced using natural gas as fuel. The steam requirement depends on the quality of steam, geology and quality of the deposits. The SOR varies between two to four and the process is continually being improved to optimise the steam requirement. The SAGD process also requires electricity to pump feedwater to the steam generators. Typically, SAGD uses about 9 kWh of electricity per barrel of bitumen (Finan and Kadak, 2010), which is also produced from natural gas turbines. Overall, the natural gas requirement for the SAGD process is in the range of 1 000-1 500 standard cubic feet (28-42 Nm^3) per barrel of bitumen, after accounting for a small amount of associated gas by-product from the SAGD process which provides about 1% of total fuel demand (McColl et al., 2008). In 2018, bitumen production from SAGD averaged ~1.6 million barrels per day and would have required about 1.6-2.4 billion standard cubic feet of natural gas daily. The energy consumption for SAGD in 2018 was equivalent to the energy supply from a 16 000-29 000 MWth power source, equivalent to six to ten current generation nuclear reactors of average 1 000 MWe capacity. SAGD operations are implemented in phases, starting at 5 000 barrels per day and growing up to between 30 000 and 200 000 barrels per day. Thermal energy requirement for SAGD operations, as a function of production capacity, was calculated assuming a SOR of 3.1, requiring 1 020 standard cubic feet of natural gas per barrel, and is shown in Figure 6.22 below.

Figure 6.22: **Thermal energy requirements for SAGD bitumen extraction**



Source: Axpo AG (2016).

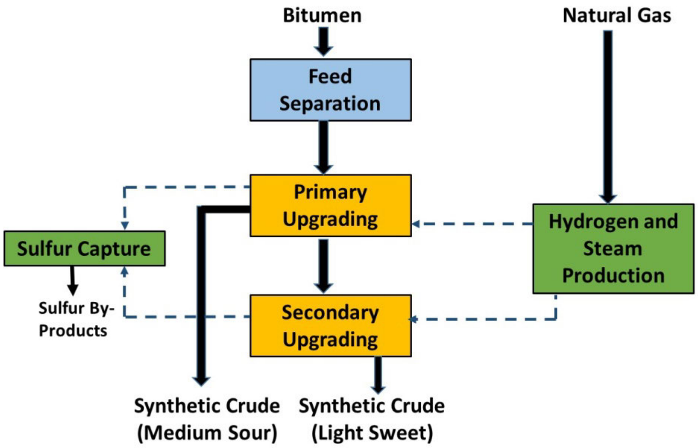
As shown in Figure 6.22, small operations with up to 35 000 barrels per day of capacity could be supported by a small modular reactor (SMR) of up to 500 MWth capacity. Larger operations with capacities ranging between 35 000 and 180 000 barrels per day could be served by multiple SMRs and large-scale operations would require large-scale reactors.

The SAGD process also requires significant amounts of make-up fresh water for steam generation, although a significant amount of water is recycled after reprocessing. About 87% of the water is recycled requiring only 0.22 barrels of fresh water per barrel of bitumen (Natural Resources Canada, 2019).

Upgrading of bitumen

In the upgrading process, bitumen is converted from a viscous oil that is deficient in hydrogen and with high concentrations of sulphur, nitrogen, oxygen and heavy metals, to a high-quality "synthetic" or "upgraded" crude oil that has density and viscosity characteristics similar to conventional light sweet crude oil, but with a very low sulphur content (Gray, 2015). Upgrading facilities may be located on site or off site and may be dedicated to a specific project or standalone facilities that process crude bitumen from many projects. After upgrading, the synthetic crude is shipped to refineries or for export by pipelines. Upgrading is done in two stages. Primary upgrading increases the hydrogen-carbon ratio either by rejecting the carbon or adding hydrogen. In the secondary upgrading stage, impurities containing sulphur and nitrogen are removed to enhance the quality of the final product. Both stages of upgrading require hydrogen. A schematic of the upgrading is shown in Figure 6.23.

Figure 6.23: **Schematic of bitumen upgrading process**



Source: Axpo AG (2016).

Upgrading plants are relatively large compared to SAGD facilities, with capacities ranging from 100 000 to 500 000 barrels per day of bitumen. The hydrogen requirement for upgrading varies with the process employed but averages at about 4 kg per barrel of bitumen processed. Hydrogen is produced by steam methane reforming using natural gas feedstock. In 2018, Alberta had a capacity to upgrade about 1.33 million barrels of bitumen per day, which would require 5 200 tons/day of hydrogen. The only technology available today to produce hydrogen without emitting greenhouse gases is conventional electrolysis, which requires an average of 50 kWh of electricity per kilogram of hydrogen (Duffy et al., 1999). However, about 90% of the electricity production in Alberta is currently based on either natural gas or coal (Natural Resources Canada, 2019). Assuming that adequate equipment is available to produce hydrogen by electrolysis of water on a large scale, it would require a nuclear power source of 11 000 MW_e, equivalent to about ten current generation nuclear reactors.

In summary, extraction of bitumen by the in situ SAGD process and its subsequent upgrading to synthetic crude oil is energy intensive. As shown above, the current level of SAGD and upgrading operations in Alberta is estimated to require between 3 and 4 billion standard cubic feet/day of natural gas for steam, hydrogen and electricity supply. The price of natural gas plays an important role in the economics of oil sands operations and therefore alternative energy sources with relatively stable prices are highly desirable. The total energy requirement for SAGD and upgrading is equivalent to 15 to 20 current generation nuclear power plants with an average capacity of 1 000 MW_e. This does not include the energy required for other operations in the oil sands sector, including mining and pipeline transportation. The energy demand is estimated at the production levels in 2018 and would increase significantly if the production of bitumen and synthetic crude oil increases with an upturn in oil prices.

Greenhouse gas emissions

In 2020, the oil sands industry contributed to about 12% of Canada's total GHG emissions (Natural Resources Canada, 2020). However, the GHG emissions from oil sands have declined 30% per barrel from 1990 to 2013. The GHG emissions (CO_2 equivalent, or CO_2e) from SAGD operations are estimated to be about 90 kg per barrel of bitumen (Finan and Kadak, 2010). In 2018, production of ~1.6 million barrels per day of bitumen per day would have emitted 144 000 tons per day of CO_2e.

Hydrogen required for upgrading bitumen is mostly produced by steam reforming of natural gas, which emits about 9.5 kg of CO_2e per kg of hydrogen produced (IAEA, 2013). Therefore, 5 200 tons per day of hydrogen required for upgrading would produce an additional ~50 000 tons of CO_2e per day.

Total CO_2e emission from in situ operations and hydrogen production for upgrading of bitumen would be about 64 Mt in 2018. Surface mining and extraction is also an energy-intensive process requiring about 280 standard cubic feet of natural gas per barrel of bitumen (Bersak and Kadak, 2007). Assuming an average 65 kg of CO_2e production per thousand standard cubic feet natural gas burnt, total emissions from 1.3 million barrels of bitumen produced in 2018 would be about 23 Mt. Total emission of 87 Mt in 2018 estimated here is somewhat higher than about 75 Mt reported in Canada's Energy Fact Book (Natural Resources Canada, 2019); the discrepancy could be attributed to technology improvements and initiatives undertaken by the oil sands industry in the last decade. Table 6.11 summarises CO_2e emissions estimated for oil sands operations in 2018.

Table 6.11: **Estimated emissions from oil sands**

Oil sands operation/process	CO_2e emissions megatons/year
SAGD in situ operations	48
Hydrogen production for upgrading	16
Surface mining and extraction	23
Total	87

Source: Axpo AG (2016)

The Canadian Energy Research Institute (CERI) (McColl et al., 2008) has made projections for CO_2e emissions from all operations including mining and extraction, in situ extraction, and upgrading. These projections show a potential increase in CO_2e emissions to 140 Mt/year by 2025 based on the technologies and use of natural gas as the fuel prevailing then.

In 2015-16, the Alberta government introduced the concept of a levy on carbon emissions. Oil sand facilities were charged a Specified Gas Emitter Regulation (SGER) levy based on each individual facility's historical emissions, irrespective of how intense or efficient that operation has been. A carbon levy based on CAD 20 per ton of CO_2e emission was to be built into the price of major fuels, including natural gas, starting January 2017. The carbon tax would have increased to CAD 30 per ton of CO_2e in the future. If the emission of GHGs was avoided using nuclear energy, it represents a saving of CAD 2.70 per barrel of bitumen produced from SAGD and a further CAD 1.2 per barrel in savings in upgrading compared with 2013, based on the proposed carbon tax of CAD 30/ton. The emissions from the oil sands were to be capped at 100 Mt/year. The carbon tax legislations were repealed in 2019 after the change in the provincial government.

6.5.3. *Economics of nuclear energy for oil sands*

There are two main considerations for the use of nuclear power in oil sands, namely, the security of energy supply and environmental impact. Natural gas is the main energy source for the SAGD operation, and its price stability is a concern affecting the economics. The use of natural gas affects the air quality (via NOx and other emissions) and represents a large component of GHG emissions. The current and evolving carbon tax structure further affects the economics of bitumen production using natural gas as the energy source. Several economic studies have reportedly been done on the application of nuclear energy for oil sands, but only a few are available in the published literature.

In 2003, Atomic Energy of Canada Limited and Canadian Energy Research Institute studied the economic viability of adapting the Advanced CANDU®[3] Reactor (ACR-700) for use in the SAGD process (Hopwood et al, 2004) and (Dunbar and Sloan, 2003). The ACR-700 is a 731 MW_e (1 983 MW_{th}) design, evolved from technological changes to previous CANDU reactor systems. Steam from the ACR-700 unit's steam generators would be directed to the saline water boilers, where it would exchange heat with the treated boiler feed water to generate SAGD steam (80% quality, 3.0 MPa). The calculated output of the facility was 78 020 m^3/day of 80% quality steam and 100 MWe (net)

3. CANDU – Canada Uranium Deuterium (a registered trademark of Atomic Energy of Canada Limited).

electricity to support the SAGD operation of 23 200 m^3/day (~145 000 barrels per day) of bitumen capacity. The study by Dunbar and Sloan (2003) concluded that the steam supply from the ACR-700 nuclear facility would be economically competitive with steam supply from a gas-fired facility (CAD 8.7/t) in 2003 without considering any carbon tax. The cost of steam supply from a nuclear facility was found to be very sensitive to capital costs and that from a gas-fired facility was very sensitive to natural gas prices. This study assumed that the steam pressure required at the SAGD wells varies between 2 to 6 MPa. The study also recognised that the economics of a central steam supply from ACR-700 would depend on the cost of transportation of steam to the individual well. It was also suggested that hydrogen and heavy water production (from hydrogen) using off-peak electricity could improve the overall economics.

A techno-economic feasibility study was performed at Massachusetts Institute of Technology (Finan and Kadak, 2010; Bersak and Kadak, 2007) to evaluate three different reactor concepts for bitumen production, including the Enhanced CANDU-6, ACR-700 and pebble bed modular reactor (PBMR). This study assumed that the steam pressure required for SAGD to be between 6 MPa and 11 MPa with a steam to oil ratio of 2 to 4. The Enhanced CANDU-6 produces steam at 4.7 MPa that could only be used for low-pressure SAGD, which was just beginning to be used. So the Enhanced CANDU-6 was judged to be suitable for electricity production for hydrogen production and other major consumers of electricity. The Advanced CANDU Reactor (ACR-700) produces steam at 6.5 MPa and so was a more promising choice for SAGD projects of 200 000 to 350 000 barrels per day capacity. However, transport of steam beyond a 10 km radium was not considered feasible because of the pressure drop and heat loss through the distribution piping network, limiting the usefulness of this reactor for SAGD operations to 200 000 barrels per day. The current generation of nuclear reactors was found to be too large for steam production and electricity production for SAGD operations alone. The second constraint with large nuclear plants is that the steam/electricity production capacity is installed all at one time, whereas the large SAGD capacity (200 000 + barrels per day) is generally installed in phases. Modular reactors, such as PBMR (500 MW_{th}), could be installed in modules, each capable of supporting 40 000-65 000 barrels per day of SAGD bitumen production with a steam to oil ratio of 2.5. The PBMR has a high outlet temperature and could produce steam at pressures required for the SAGD operation. The economics of electricity production using nuclear power were found to be favourable at natural gas prices of above CAD 10 per million (MM) Btu in 2008. The break-even natural gas prices for steam production were estimated at CAD 5.65/MMBtu for the ACR-700, CAD 6.85/MMBtu for the Enhanced CANDU-6, and CAD 6.75/MMBtu for the PBMR. All break-even prices would be lower if a price is put on GHG emission. This study also considered higher overnight costs and labour costs for nuclear plants in remote locations for oil sands.

In 2008, the Canadian Energy Research Institute evaluated various alternative energy sources for oil sands operations, including current generation and generation III nuclear reactors, small reactors (Toshiba 4S), coal gasification, and carbon capture and storage (McColl, 2009). The cost of baseload nuclear thermal energy was found to be comparable while that from the small reactor was higher. The most economical option was the status quo.

In March 2009, the Petroleum Technology Alliance of Canada published a study on the assessment of three high temperature SMR designs as the energy source for a greenfield 120 000 bpd SAGD plant to be built in four, 30 000-bpd stages at three-year intervals (Petroleum Technology Alliance of Canada, 2009). Three reactor designs assessed: the Toshiba 4S (135 MWth), the General Atomics Modular High Temperature Gas-cooled Reactor (MHTGR – 350 MWth) and PBMR Pty Ltd's Pebble Bed Modular Reactor (PBMR – 500 MWth). Steam and electricity requirements were estimated to be 284 MWth and 23 MWe, respectively, assuming a SOR of 2.5 with steam saturated at 9.5 MPa for each stage of 30 000 bpd. Since the steam supply to the wells cannot be shut down for extended periods of time, a backup steam supply is required during the outage of the nuclear plant. Three HTR designs were assessed using twenty different criteria and were found to be comparable. This being a First-of-Kind application for a First-of-Kind reactor design, the technical, business, regulatory and construction risks were assessed to be medium to high. Capital investment in nuclear steam plants were estimated to be in the range of CAD 3 100 to CAD 3 500/kWth (2009).

The Idaho National Laboratory (INL) evaluated the integration of high-temperature gas-cooled reactors (HTGRs) for oil sands processes in a study published in October 2011 (Gibbs and Asgarpour, 2011). The proposed facility consisted of the energy supply plant with 5 x 600MWth

HTGRs, SAGD operations with 150 000 bpd bitumen production and a 145 000 bpd upgrading plant. The HTGR energy supply plant was proposed to provide steam for SAGD (770°C), electric power (200 MWe) for various operations and heat (superheated steam at 850°C) for the bitumen processing and upgrading. Hydrogen production was assumed to be by a conventional natural gas reforming process. Natural gas boilers were also considered as backup for SAGD steam supply. The steam would be supplied from the central HTGR energy supply plant to up to 25 km. The cost of heat from the HTGR was found to be higher than that supplied by natural gas at the then prevailing price between USD 5 and 6/MMBtu. For HTGR heat to be competitive with natural gas, a carbon tax of USD 120/ton of CO_2 would be required.

In 2012, the Petroleum Technology Alliance of Canada completed a study on innovative applications of electricity in the oil sands development (Petroleum Technology Alliance of Canada, 2012). This study evaluated technical and economic prospects of applying electricity-based technologies to SAGD bitumen production, upgrading and other emerging technologies for in situ bitumen production from oil sands. This study was relevant to evaluating the economics of using electricity instead of steam from the nuclear plant as the heat source, since electricity can be transmitted over long distances. The study compared the break-even price of electricity, defined as the price of electricity at which the annualised costs for the base case and the new technology using electricity are the same, to the current price of electricity. The break-even price required for various versions of SAGD and upgrading technologies was significantly lower (by CAD 15-42/MWh) compared with the average price of CAD 77/MWh in 2012, assuming natural gas average price of about CAD 4.5/MMBtu. Electrical technology applications for SAGD were found closer to current economics than for the upgrading operations. The study concluded that none of the SAGD or upgrading technologies using electricity as heat source would be viable unless lower-cost and lower-emission sources of electricity are available. The study also looked at emerging in situ technologies employing resistance heating and dielectric heating for bitumen reserves that are deeper than can be economically exploited by SAGD. These electricity-intensive technologies could be more economical with electricity available from a nuclear plant.

In November 2015, the government of Alberta announced its Climate Change Leadership Plan aimed first at phasing out coal burning and second at limiting GHG emissions from oil sands operations to less than 100 Megatons per year. Alberta Innovates, an Alberta provincial organisation, contracted Pacific Northwest National Laboratory (PNNL) to provide an assessment of SMRs for oil sands applications, with a view to identify viable SMR designs that could be deployed for oil sands by 2030. The PNNL assessed 26 SMR concepts representing seven general categories: (1) integral pressurised water reactors, (2) heavy water reactors, (3) high-temperature gas-cooled reactors, (4) molten salt reactors, (5) sodium fast reactors, (6) gas-cooled fast reactors, and (7) heavy liquid metal cooled reactors (Short et al., 2015). The reactor concepts were assessed using 11 criteria, as follows:

- commercial deployment ability;
- steam quality;
- technology readiness level;
- steam pressure and temperature;
- electricity production capacity;
- safety;
- spent fuel management;
- low-level and intermediate-level waste management;
- decommissioning;
- adaptability to Alberta; and
- levelised cost of electricity (competitiveness with combined-cycle natural gas and geothermal power prices of CAD 50-60/MWh in 2015).

In the PNNL's study (Short et al., 2015), the HTGRs ranked the highest, which is not unexpected since HTGRs are able to provide steam of enough quality and at temperatures and pressures required for the SAGD operations.

The PNNL study was further expanded to Phase II to provide a techno-economic assessment of SMRs and deployment challenges. Phase II of the PNNL study (Short and Schmitt, 2018) selected the integral PWR (iPWR) design for surface mining operations and the HTGR technology for SAGD operations. The iPWR was selected for the surface mining because it could be easily integrated into the process flowsheets for providing electricity and steam requirements of a reference facility. Although the iPWR was meant to provide both electricity and steam, the economic comparison was done on the basis of the levelised cost of electricity (LCOE). The LCOE for the iPWR was estimated at CAD 105/MWh compared to CAD 72/MWh for a natural gas cogeneration plant at 2014 currency levels. Several considerations for reducing the cost of iPWR based on the most significant cost contributors were also discussed. The HTGR technology was selected for the SAGD operation in the Phase II of the PNNL study to meet the high-pressure steam quality requirements of the SAGD. The LCOE for the HTGR was estimated to be CAD 128/MWh compared to CAD 72/MWh for the natural gas cogeneration plant. Similarly, the cost of hydrogen produced by high-temperature coupled to the HTGR was found to be significantly higher (CAD 6.4-6.9/kg H_2) than the conventional natural gas steam reforming (CAD 2.2-2.3/kg H_2). The cost calculations for the electricity and hydrogen produced from natural gas include a carbon tax of CAD 30/ton of CO_2.

The Phase II study of the PNNL concluded that SMR technologies are not currently competitive with natural gas cogeneration of electricity and process steam for the surface mining and with the once-through natural gas-fired steam generators for the SAGD application, or with production of hydrogen by steam methane reforming for a bitumen upgrading application, even after imposition of a carbon tax.

Various generation IV reactors and small modular reactors are being developed to operate at higher temperatures and higher efficiencies with inherent safety features. Similarly, hydrogen production by water-splitting using thermal and electrical energy from nuclear reactors is being developed. In the longer term, these technologies provide economical alternatives for oil sands operations with significant impact on GHG reductions. Canadian Nuclear Laboratories (Moore et al., 2016) developed a generation IV supercritical water-cooled reactor (SCWR) concept with outlet temperature of 625°C and pressure of 25 MPa. This type of reactor would be capable of supplying high-temperature steam for the SAGD operation as well provide high-temperature thermal energy for efficient hydrogen production and upgrading operations. An economic analysis for a 1 200 MWe plant was performed in 2007 constant dollars and the results are presented in Table 6.12 below.

Table 6.12: **SCWR economic analysis**

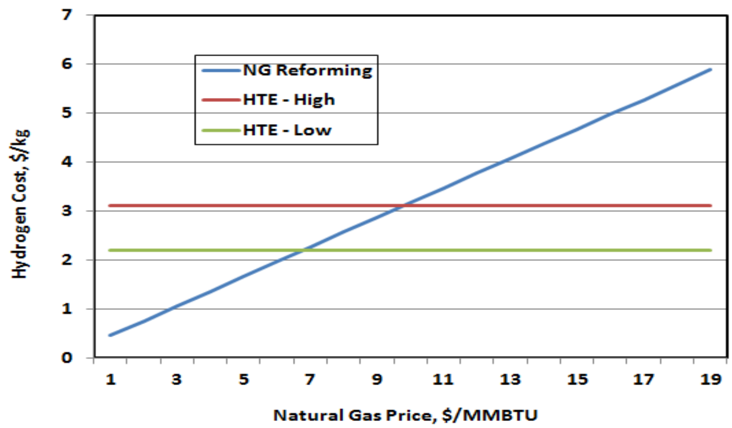
Capacity	1 200 MWe
Thermodynamic efficiency	48%
Outlet temperature	625°C
Pressure	25 MPa
Total capital investment cost	USD 3 863 M (2007)
Discount rate	5%
Operating life	40 years
Levelised unit cost of electricity (LUEC)	USD 51.4 (2007)

Source: Axpo AG (2016)

The cost of electricity produced from an SCWR is lower compared to the costs estimated in the MIT study (Bersak and Kadak, 2007) and would be equivalent to that produced from combined-cycle natural gas plant with a natural gas price of CAD 3 per million Btu. The escalated value of the levelised unit cost of electricity from an SCWR in 2012 was CAD 57/MWh, which compares favourably with the CAD 77/MWh actual average price in 2012 (Petroleum Technology Alliance Canada, 2012).

Canadian Nuclear Laboratories have been studying the processes for producing hydrogen by splitting water using thermal and electrical energy from high-temperature, next-generation nuclear reactors. One of technologies that has been studied extensively is the high-temperature electrolysis of water using high-temperature steam from the next-generation nuclear reactors (Ryland et al., 2007). The economics of producing hydrogen on a large scale (~200 million standard cubic feet per day) was investigated and the cost of hydrogen production is shown in Figure 6.24. A large-scale hydrogen plant would be suitable to meet the demand of an upgrading plant. The cost of hydrogen production ranged between USD 2.2 and 3.1 over the range of capital and operating costs used in the study and corresponds to a range of natural gas prices of USD 6.8 to 9.8/MMBtu in 2007.

Figure 6.24: **Cost of hydrogen production using high-temperature electrolysis and supercritical water-cooled reactor (reference year 2007)**



Source: Canadian Nuclear Laboratories Ltd (2018).

Large-scale hydrogen production can also be achieved using thermochemical copper-chlorine cycle connected to an SCWR (Rosen et al., 2010).

6.5.4. *Implementation of nuclear for oil sands*

In 2005, Energy Alberta was established to build a nuclear plant in northern Alberta (WNA, 2017). The company was later acquired by Bruce Power, which in March 2008 filed an application for a licence to prepare the site for up to 4 000 MW_e nuclear capacity. The main discussion centred upon building twin ACR-1000 reactors primarily for electricity rather than steam production. Most of the generated power would be supplied to the oil sands consumers through the grid, but during off-peak hours part of the generated power could be used for hydrogen production for upgrading plants. In March 2009, Bruce Power announced that the Whitemud site, located about 30 km from the town of Peace River and about 500 km northwest of Edmonton, had been selected and that an environmental assessment was expected to be launched in 2010. The project, known as the Peace Region Nuclear Power Plant Project, would involve the construction of up to four reactors to provide between 3 200 and 4 400 MW_e of capacity. The reactor designs under consideration were the EPR (two units), AP 1 000 (four units), and the ACR-1000 (two twin-units). The initial project concept was primarily for electricity rather than steam production. In December 2011, Bruce Power decided to shelve the project.

While innovators in the oil sands industry are aware of the long-term possibilities of implementing nuclear technology, for the most part they are currently occupied with closer-to-deployment technical advances (Petroleum Technology Alliance Canada, 2012). Producing bitumen from oil sands on commercial large scale required decades of effort, with active involvement from both business and government. Bringing nuclear power to the oil sands is a challenge of a similar scale, requiring further technology development. A multi-stakeholder technology development process will be required to narrow the technology gaps to a point where cost ranges and time frames are sufficiently defined so that business models can be contemplated. Nevertheless, there is an opportunity to significantly reduce GHG emissions from oil sands through use of nuclear energy, which also offers a secure supply of energy, provided technological challenges are overcome and economic viability is established.

Based on the studies conducted to date, various possibilities of using nuclear energy for oil sands operations exist and need to be further investigated. In particular, the following cases need further consideration in terms of economics and impact on reducing GHG emissions.

- use of SMRs to provide steam to distributed SAGD operations; with phased implementation of both SAGD and modular SMRs;
- use of off-site large-scale reactors (current and next generation) to supply electricity for the SAGD to generate steam using electric boilers;
- use of nuclear reactors to produce hydrogen to upgrade bitumen;
- use of SMRs to provide electricity for novel electricity-intensive techniques for in situ extraction based on resistance heating and dielectric heating for in situ production of bitumen.

6.5.5. *Metric conversion factors*

Table 6.13: **Conversion factors**

British units	Metric units
1 Canadian barrel of oil at 60°F	0.15891 m^3 at 15°C
1 cubic foot of natural gas at 14.65 psia and 60°F	0.02817399 m^3 at 101.325 kPa and 15°C
1 million Btu (MMBtu)	1.05505585 Giga Joules
1 million Btu (MMBtu)	0.293071 MWh

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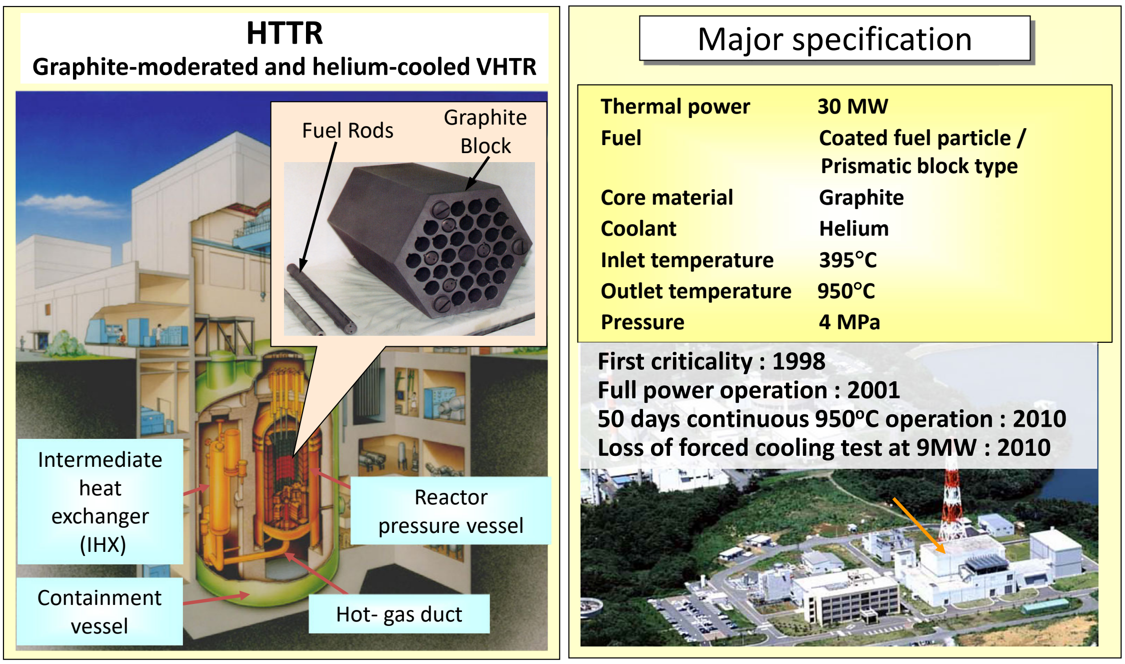
6.6. Japan's VHTR cogeneration system – GTHTR300C

6.6.1. *Development of the VHTR cogeneration system in Japan*

VHTR test reactor – HTTR

Japan has continued investing in the development of the VHTR since the 1970s. The first milestone was the completion of construction in 1998 of the 30 MWt high-temperature engineering test reactor (HTTR). The HTTR was then put in a series of successful operation runs (see Figure 6.25) that served to not only validate its underlining technologies developed in terms of fuel, structural graphite, metals and O&M techniques, but also demonstrate the intended design features of a commercial VHTR, including inherent safety and the heat transfer of the 950°C reactor coolant via a superalloy intermediate heat exchanger to potential heat users such as a thermochemical hydrogen production plant.

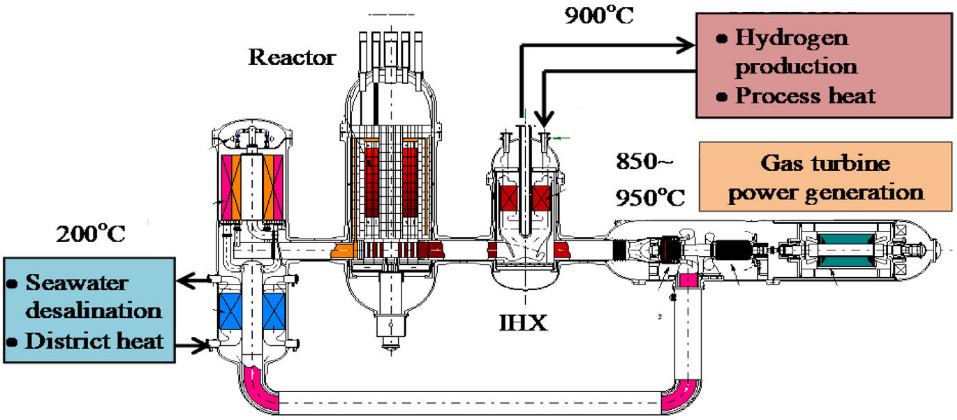
Figure 6.25: **HTTR – a VHTR test reactor constructed at JAEA Oarai R&D Center**



Commercial cogeneration reactor design – GTHTR300C

Based on the HTTR technologies developed and with additional development carried out since 2001 by the JAEA for power conversion and heat application technologies, the JAEA has proposed the baseline design of a commercial VHTR system, known as the Gas Turbine High Temperature Reactor of 300 MWe for Cogeneration (GTHTR300C) as depicted in Figure 6.26. Along with power generation, the GTHTR300C enables a range of cogeneration applications (see Table 6.14). The estimated costs of power generation were published, and a summary is provided in Table 6.15 (Takei et al., 2006).

Figure 6.26: **Japan's VHTR system – GTHTR300C for power generation with various cogeneration options**



Source: JAEA (2016).

Table 6.14: **Major technical parameters (GTHTR300C)**

Technology developer:	JAEA with Mitsubishi, Toshiba, Fuji Electric, NFI, etc.
Country of origin:	Japan
Reactor type:	Prismatic HTGR
Electrical capacity (MWe):	100~300 MWe
Thermal capacity (MWth):	< 600 MWt
Design capacity factor:	>90%
Design life (years):	40-60
Coolant:/moderator	Helium/graphite
Moderator:	Graphite
Primary circulation:	Forced circulation
System pressure:	5-7 MPa
Reactivity control mechanism:	Control rod
Reactor pressurised vessel height/diameter (m):	23/8
Coolant temperature, core outlet (°C):	850-950
Coolant temperature, core Inlet (°C):	587-633
Integral design:	No
Power conversion process:	Direct Brayton cycle
High-temperature process heat:	Yes
Low-temperature process heat:	Yes

Table 6.14: **Major technical parameters (GTHTR300C)** (cont'd)

Cogeneration capability:	Yes
Design configured for process heat applications:	Yes
Distinguishing features:	Multiple cogeneration applications of power generation, hydrogen production, process heat supply, steelmaking, desalination, district heating.
Safety features:	Inherent
Fuel type/assembly array:	UO_2 tristructural-isotropic ceramic-coated particle
Fuel block length (m):	1
Number of fuel columns in core:	90
Average fuel enrichment:	14%
Average fuel burnup (GWd/ton):	120
Fuel cycle (months):	36-48
Number of safety trains:	2
Emergency safety systems:	Inherent
Residual heat removal systems:	Inherent
Refuelling outage (days):	30
Modules per plant:	Up to 4 reactors
Estimated construction schedule (months):	24-36
Seismic design:	>0.18 g automatic shutdown
Predicted core damage frequency:	$<10^{-8}$/reactor year
Design status:	Basic design with HTTR and equipment validation

Table 6.15: **GTHTR300C power generation cost**

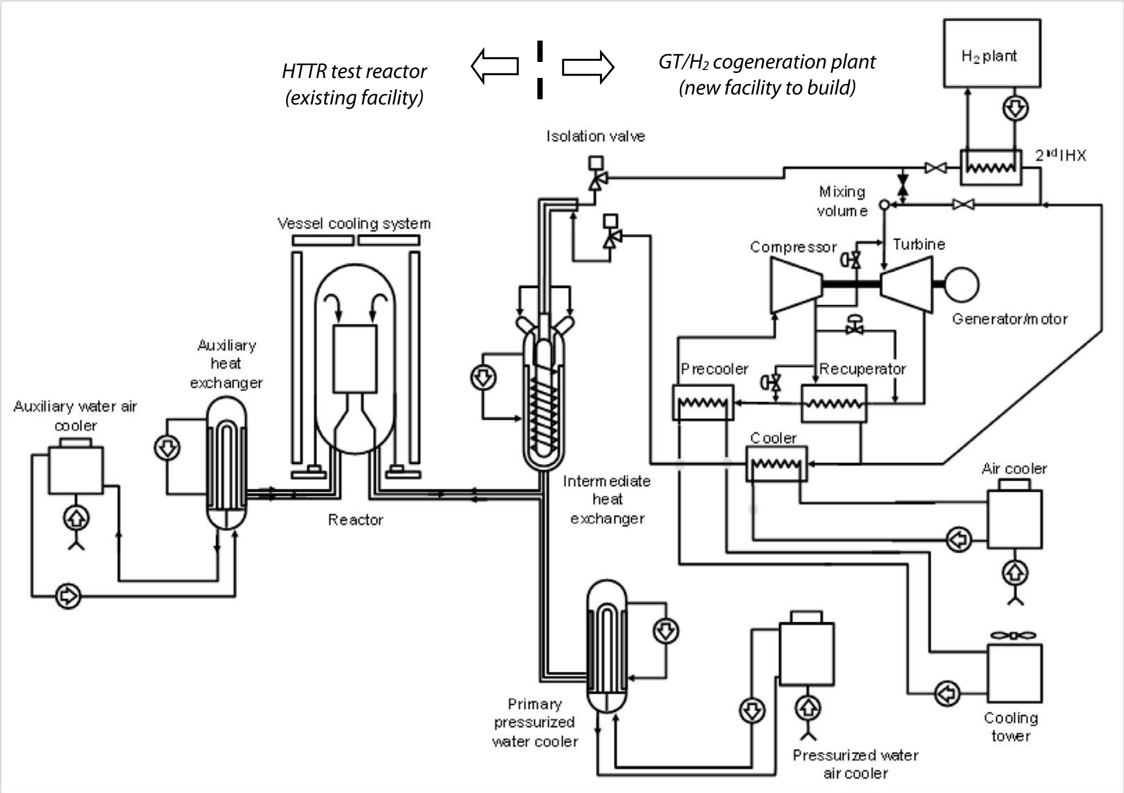
Reactor outlet temperature		850°C	950°C
Reactor thermal power	MWt	600	600
Net power generation	MWe	274	302
Net power generation efficiency	%	45.6	50.4
Load factor	%	90	90
Overnight construction cost	USD million	456	456
Construction period	Years	4	4
Plant lifetime	Years	40	40
Depreciation period	Years	16	16
Residual value	%	10	10
Discount rate	%	3	3
Interest rate	%	3	3
Property tax rate	%	1.4	1.4
Levelised cost of electricity	US cent/kWh	3.20	2.87
Capital	US cent/kWh	1.01	0.90
O&M	US cent/kWh	0.82	0.74
Fuel	US cent/kWh	1.22	1.09
Decommissioning	US cent/kWh	0.15	0.14

Source: JAEA (2016).

Demonstration test of nuclear hydrogen cogeneration – HTTR-GT/H_2

The pre-licensing basic design for a cogenerating HTGR test plant system was carried out by the JAEA (Yan et al., 2016). The plant to be coupled to the JAEA's existing 30 MWt 950°C test reactor HTTR, as shown in Figure 6.27, is intended as a system technology demonstrator for the JAEA's commercial GTHTR300C plant design. More specifically, the test plant of the HTTR-GT/H2 aims to 1) demonstrate the licensability of the GTHTR300C nuclear cogeneration commercial system described above; 2) confirm the operation control and safety of such a cogeneration system; and 3) improve accuracy of cost estimation for such a cogeneration system. With construction and operation expected to be completed around 2030, the test plant is expected to be the first-of-a-kind HTGR-powered cogeneration plant operating on the two advanced energy conversion systems of a closed-cycle helium gas turbine for power generation and a thermochemical iodine-sulphur water-splitting process for hydrogen production.

Figure 6.27: **Demonstrating HTTR coupling of nuclear hydrogen cogeneration system**



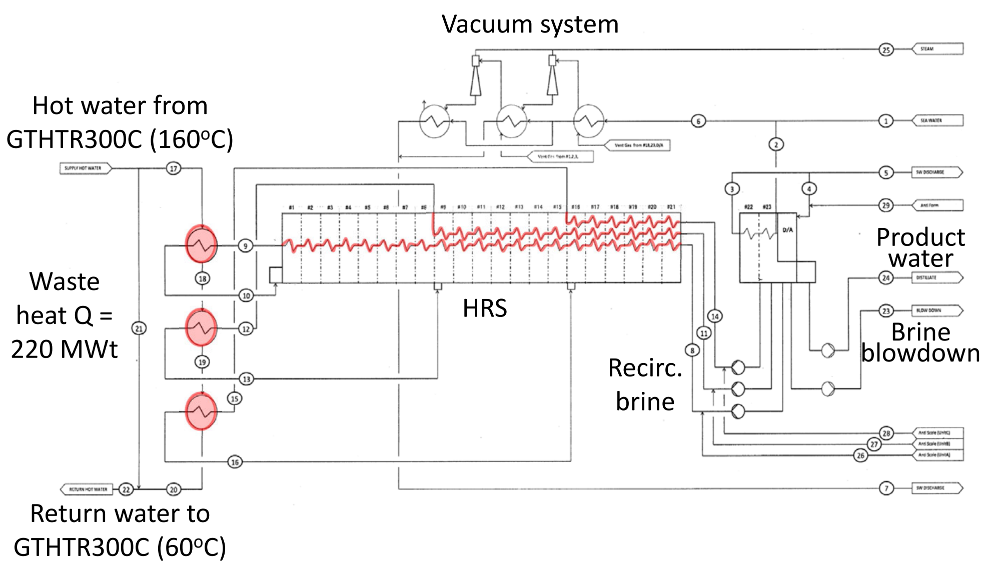
Source: JAEA (2016).

6.6.2. **Case study I: VHTR for desalination cogeneration**

Description of desalination cogeneration system

Figure 6.28 shows the schematic of a multi-stage flash (MSF) desalination process specially configured and optimised to efficiently recover the sensible waste heat of the GTHTR300C power conversion cycle. The MSF scheme increments the thermal load of the multi-stage heat recovery section (HRS) in several steps as opposed to keeping it constant in the traditional MSF process. As the number of steps increases, more waste heat becomes recoverable while the top brine temperature, a sensitive MSF process parameter, increases. Both lead to higher water yield. Operating with a similar number of stages, the current process is shown to produce 45% more water than the traditional MSF process operating over the same temperature range. Since only the reactor waste heat is used, the desalination cogeneration does not penalise the reactor power generation. Table 6.16 lists production parameters for a four-reactor plant.

Figure 6.28: **The MSF specially configured for cogeneration with use of waste heat (in form of hot water) rejected from the GTHTR300C power generation cycle**



Source: JAEA (2016).

Table 6.16: **GTHTR300C desalination plant production parameters**

Reactor thermal power	2 400 MWt (4 x 600 MWt)
Reactor outlet temperature	950°C
Gross power generation	1 232 MWe
Net power generation	1 208 MWe
Desalination output	200 000 m^3/d
Net power generation efficiency	50.4%
Cogeneration efficiency	83.7%

Estimated cost of desalination cogeneration

The water cost is estimated by a domestic original equipment manufacturer experienced in the Middle East desalination markets. Based on general Middle East market conditions, the cost of water produced from the GTHTR300C is estimated and compared with those of the conventional MSF cogenerating with an oil and gas-fired combined-cycle gas turbine (CCGT) power plant. These results are summarised in Table 6.17.

The capital cost including engineering, equipment procurement, and on-site construction is estimated to be 35% higher for the GTHTR300C's desalination plant because of the multi-compartmental configuration of the HRS as opposed to once-through HRS in the conventional plant.

The heat consumption for a desalination plant is provided by the waste heat at no cost when cogenerating with the GTHTR300C. In the case of the CCGT, this heat is assumed to be mostly efficiently provided by supplemental firing in a heat recovery steam generator. The fuel consumption required for supplemental firing without affecting CCGT power generation rate is then calculated. Referring to the World Bank Commodity Price Data (Pink Sheet) (World Bank, 2015), the price of crude oil for the ten-year average (July 2004-July 2014) of the three benchmarks (Brent, Dubai and WTI) is in the range of USD 79.8-84.1/bbl. During the same ten-year period, the average natural gas benchmark prices (United States, Europe and Japan) are in the range of USD 5.6-11.1/MMBtu and benchmark prices (Australia, Colombia and Africa) are in the range of USD 76.2-82.8/ton. The lower values of the above ranges for crude oil, natural gas and coal are used to calculate the heat costs of the CCGT. In the case of coal, a 20% premium is added to account for the additional cost of equipment required to combust the solid fuel.

Table 6.17: **Desalination cost comparison**

Plant ->	CCGT desalination plant			GTHTR300C desalination plant
	Oil-fired	Gas-fired	Coal-fired	
Capital (USD/m³)	0.29	0.29	0.29	0.39
Energy (USD/m³)				
Heat	1.65	0.67	0.48	0.04
Electricity	0.13	0.13	0.13	0.09
Operation (USD/m³)				
Consumables	0.02	0.02	0.02	0.02
O&M	0.03	0.03	0.03	0.03
Water cost (USD/m³)	**2.13**	**1.14**	**0.95**	**0.57**

Source: JAEA (2016).

Analysis of market profitability

Table 6.18 summarises the estimated profitability of deploying the GTHTR300C to add new capacity or to replace an existing oil and gas-fired plant for power and desalination cogeneration for the Middle East market. The estimation assumed the market conditions given in Table 6.19. Based on the production parameters in Table 6.16, the profit margin to deploy GTHTR300C in the Middle East market is estimated to be 248% relative to the oil-fired plant and 113% relative to the gas-fired plant. The large profit margins would provide ample cushion for investment against even high volatility in world commodity prices.

Table 6.18: **Profitability of GTHTR300C (Middle East deployment)**

Replaced fuel desalination plant		Oil	Natural gas	Coal
GTHTR300C plant cost	USD million/year	262	262	262
Electricity and related commodity saving	USD million/year	786	481	383
Water and related commodity saving	USD million/year	126	77	48
Net profit	USD million/year	651	297	170

Table 6.19: **Market conditions assumed**

Parameters	Value	Notes
GTHTR300		
Power generation cost	3.08 cent/kWh	JAEA estimation (2006)
Water cost	USD 0.57/m^3	
Market prices		
Electricity price	0.83 cent/kWh	Consumer prices: 1~6 cent/kWh SA; 6-10 cent/kWh Dubai
Water price	USD 0.75/m^3	Consumer prices: USD 0.03/m^3 Riyadh; USD 2.16/m^3 Dubai
Crude oil		
Commodity prices	USD 86/bbl	10 years world average
Domestic consumption	USD 10/bbl	Government subsidised
Natural gas		
Commodity prices	USD 10/MMBtu	10 years world average
Domestic consumption	USD 2.5/MMBtu	Government subsidised
Coal		
Commodity prices	USD 87/ton	10 years world average
Domestic consumption	USD 9.6/ton	Government subsidised

Contribution of VHTR carbon offsetting to Japan's national CO_2 reduction goals

At the Paris COP21 in December 2015, Japan committed to an Intended Nationally Determined Contribution (INDC) that foresees reducing greenhouse gas (GHG) emissions by 26% below 2013 levels in 2030. In the longer term, the Basic Environment Plan of Japan (Ministry of the Environment of Japan, 2014) sets the goal of reducing CO_2 emission by 80% below the 1990 level in 2050 (Table 6.20).

Japan has established the Joint Crediting Mechanism (JCM), also known elsewhere as carbon offsetting, to facilitate contributions from Japan's low-carbon technologies, products, systems, services and infrastructure to the sustainable growth of developing countries. The mechanism encourages GHG reductions, which count towards Japan's emission reductions. Currently, Japan has a JCM agreement with 17 countries including Indonesia, Mexico, Myanmar, Saudi Arabia, Viet Nam and others. Developed countries such as Canada, Korea, and Switzerland and the EU are using or considering similar international carbon offsetting actions to achieve their domestic CO_2 reduction targets.

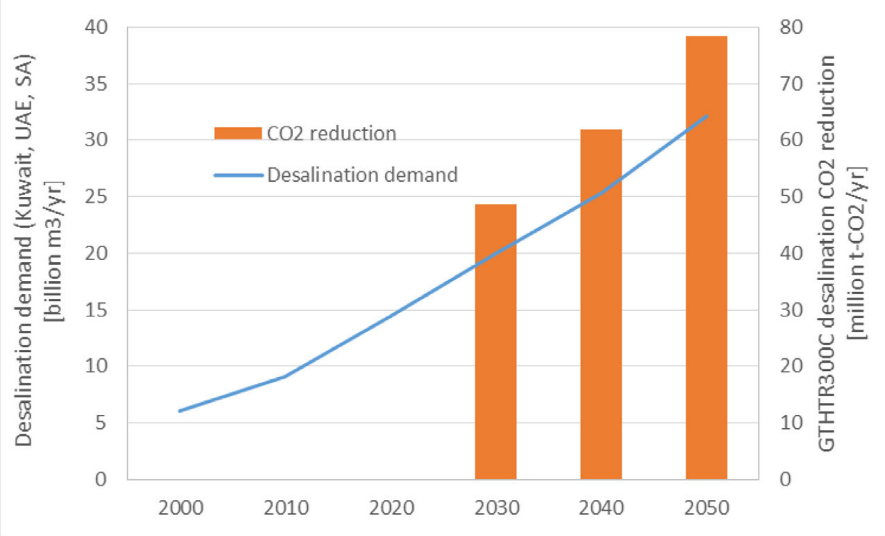
Table 6.20: **CO_2 emission reduction goals of Japan**

				COP21 INDC target of Japan (December 2015)	Basic Environmental Plan of Japan (April 2012)
Year	1990	2005	2013	2030	2050
Energy-related CO_2 emission (million t-CO_2)	1 070	1 219	1 235	927	214
Japan's CO_2 reduction target amount (million t-CO_2)	-	-	-	308 (26% of 2013 level)	856 (80% of 1990 level)

From 1980 to 2010, world desalination demand increased from 3 to 27 billion m^3/year, which is an average annual increase of 7.7%. Much of this occurred in the Middle East. For example, the combined demand of three Middle East countries, Kuwait, Saudi Arabia and the United Arab Emirates, was 33% of the world total in 2010 (Global Water Intelligence, 2010). For the period 2010~2050, growth in desalination demand is forecast to match that for world GDP, reaching 50 billion m^3/year in 2030 and 76 billion m^3/year in 2050 (IEEJ, 2014a).

The most efficient thermal desalination plant based on CCGT cogeneration consumes about 50 kWh per cubic metre of water. If the GTHTR300C for desalination is to capture 20% of the desalination markets in Kuwait, Saudi Arabia and the United Arab Emirates, the carbon offsetting achieved would be 49 million t-CO_2/year in 2030 and 78 million t-CO_2/year in 2050 (Figure 6.29), which would contribute to 16% and 9% of Japan's emission reduction target (308 and 856 million t-CO_2/year) in 2030 and 2050 respectively.

Figure 6.29: **Desalination demand and CO_2 reduction by GTHTR300**



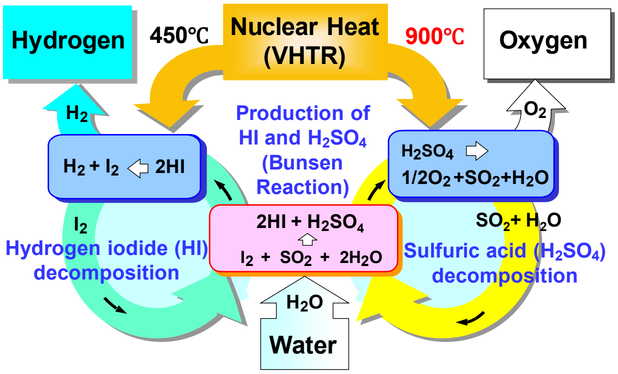
Source: JAEA (2016).

6.6.3. *Case study II: VHTR for hydrogen cogeneration*

Description of hydrogen production system options with VHTR

Figure 6.30 depicts the principle of the iodine-sulphur process, which involves three inter-cyclic thermochemical reactions to decompose water molecules into H_2 and O_2 gas products with high-temperature heat and electricity as required energy input and with water as the material feed. All process materials other than water are reagents.

Figure 6.30: **Principle of the iodine-sulphur process for nuclear hydrogen production**



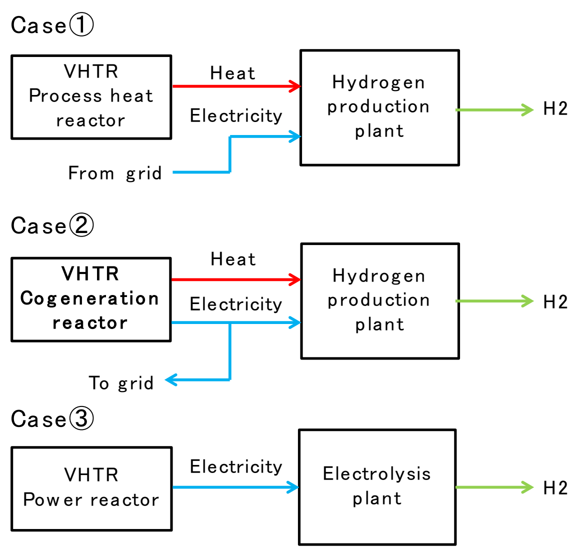
Source: JAEA (2016).

Although a thermochemical process, the iodine-sulphur process in practice consumes considerable electricity to power hydrogen plant equipment, including the process pump, gas circulator and fluid processors. According to the JAEA's flowsheet design, the heat to electricity consumption ratio is close to seven units of thermal energy to one unit of electricity. Further, a centralised large-scale hydrogen production plant serviced by a nuclear reactor would consume additional electricity needed to compress or liquefy the hydrogen product for delivery at the plant gate. For example, the electricity consumption for liquefaction of hydrogen is approximately 7 MWh per ton of hydrogen.

Three cases of hydrogen production with the VHTR are considered. They are outlined in Figure 6.31:

- *Case 1: The VHTR acts as process heat reactor to produce and supply the heat* required by the iodine-sulphur process hydrogen production plant while the electricity required by the hydrogen plant is imported from grid at wholesale price for industrial users. The heat is transferred via the intermediate heat exchanger as shown in Figure 6.26. The gas turbine power conversion system, which includes a gas turbine generator set and associated heat exchanger vessel unit, is replaced with an electric motor-driven helium gas circulator system. The desalination plant is also excluded. Figure 6.32 records the historical prices of electricity in a twenty-year period in Japan. The lowest price charged to industrial users was JPY 13.65/kWh achieved in 2010 while the highest was JPY 18.85/kWh in 2014. Alternatively, the electricity needed may be produced by separate nuclear power reactors such as the VHTR and light water reactor (LWR). In this case, the price of electricity supplied for hydrogen production might be the least costly if the utility that owns the power reactor also owns the VHTR process heat reactor.

Figure 6.31: **Case studies of VHTR hydrogen production plant arrangement**



Source: JAEA (2016).

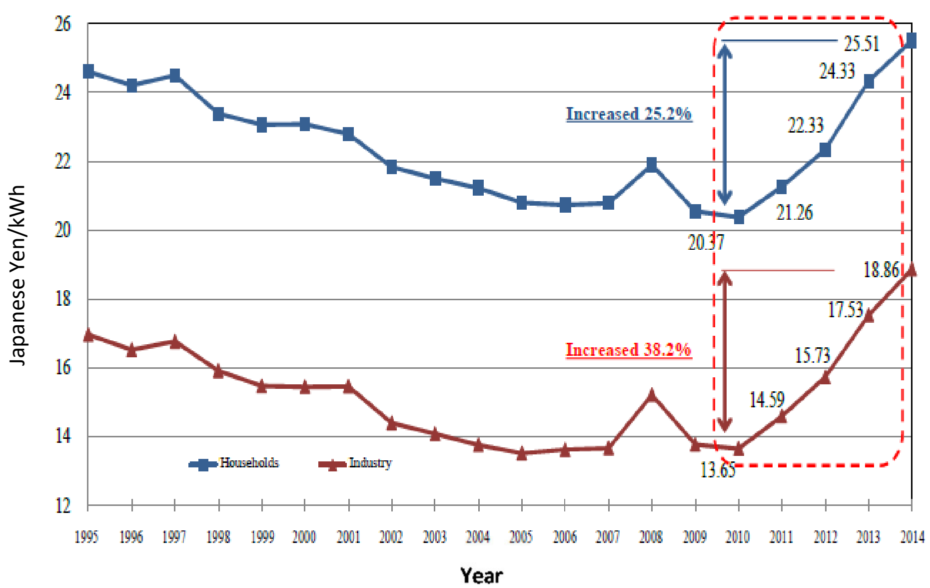
- *Case 2: The VHTR cogenerates both the heat and electricity* to supply to the hydrogen plant with surplus electricity, if any, to be exported and sold to the grid. The reactor plant design is identical to the GTHTR300C shown in Figure 6.26 but excluding the desalination plant.
- *Case 3, The VHTR produces and supplies only the electricity*, all of which is used to power a conventional water electrolysis plant for hydrogen production. The reactor system design is the system shown in Figure 6.26 but excluding the intermediate heat exchanger and the desalination plant.

The plant systems for the three cases are designed based on the-state-of-the-art of VHTR and hydrogen technologies developed in Japan. The resulting production parameters are summarised in Table 6.21.

Table 6.21: **VHTR hydrogen production performance parameters**

		Case 1	Case 2	Case 3
Reactor thermal power	MWth	600	600	600
Reactor outlet temperature	°C	950	950	850
Gross power generation	MWe	-	204	280
Reactor plant elec. load	MWe	6	6	6
H_2 production rate	t/d	236	67	108
	Nm^3/h	112 100	31 800	50 300
H_2 plant heat consumption	MWth	600	170	-
H_2 plant elec. consumption	MWe	103.5	27.6	241.5
H_2 production efficiency	%	47.3	50.1	34.5
H_2 liquefaction elec. consumption	MWe	72.6	20.1	32.5
Total elec. consumption (H_2 production and liquefaction)	MWe	176.0	48.2	280.0
Replacement interval	Year	10-20	10-20	10

Figure 6.32: **Electricity prices for residential and industrial users in Japan**



Source: METI (2015).

Estimation of hydrogen production cost

Table 6.22 lists the financial parameters used in the cost estimation. The nuclear plant parameters including discount rate, interest, and property tax are typical values used to estimate the cost of utility nuclear power reactors in Japan. An average lifetime of 20 years for an iodine-sulphur process hydrogen plant for cases 1 and 2 is expected to be achievable. The cost for a one-time replacement of a hydrogen plant is considered during the reactor lifetime. For simplicity, the electrolysis plant of Case 3 assumes the same scheme of lifetime and replacement.

Table 6.22: **Financial parameters**

Plant load factor	90%
Reactor plant lifetime	40 years
Depreciation period	16 years
Residual value	10%
Hydrogen plant operation term	40 years
Depreciation period	10 years
Residual value	10%
Discount rate	3.0%
Interest rate	3.0%
Property tax rate	1.4%

Table 6.23 lists the cost of electricity consumed for hydrogen production in each case. Case 1 selects the historically lowest price of electricity as Case 1a and the highest price as Case 1b. Cases 2a and 3a are based on the cost of GTHTR300 power generation estimated jointly by the JAEA and domestic nuclear vendors. The costs of electricity for Case 2a and Case 3a are the same because of their identical power generation infrastructure design in the nuclear plant. Case 2b and Case 3b are equivalent to the increases in cost of Japan's current LWR power generation due to policy changes.

Table 6.23: **Cost of electricity for hydrogen production**

In US cent/kWh

	Case 1a	Case 1b	Case 2a	Case 2b	Case 3a	Case 3b
Capital	-	-	1.16	1.26	1.16	1.26
O&M	-	-	0.82	1.19	0.82	1.19
Fuel	-	-	1.22	1.17	1.22	1.17
Policy, etc.	-	-	0.00	0.86	0.00	0.86
Grid electricity, low/high (industry users)	11.38	15.71	-	-	-	-
Total	**11.38**	**15.71**	**3.20**	**4.48**	**3.20**	**4.48**

Table 6.24 lays out estimates for the cost of heat supply for hydrogen production in each case. Case 1 and Case 2 are based on the designs and associated costs evaluated by the JAEA with its domestic nuclear vendors. Because Case 3 is an electrolysis method, heat consumption is zero. The cost of heat in Case 2 is lowered due to the advantage of cogeneration, in that most components of the nuclear plant in Case 2 are shared between power generation and heat supply while all components in Case 1 are dedicated to heat supply only.

Table 6.24: **Cost of heat energy for hydrogen production**

In US cent/kWh

	Case 1a	Case 1b	Case 2a	Case 2b	Case 3a	Case 3b
Capital	0.84	0.90	0.82	0.86	-	-
O&M	0.63	0.84	0.57	0.73	-	-
Fuel	0.50	0.53	0.56	0.53	-	-
Policy, etc.	0.00	0.40	0.00	0.40	-	-
Total	**1.98**	**2.67**	**1.94**	**2.53**	**0.00**	**0.00**

Table 6.25 lists hydrogen liquefaction storage specifications. Hydrogen production is different for each reactor so each case uses different reactor numbers to make the production amount roughly similar.

Table 6.25: **Hydrogen liquefaction storage**

		Case 1a and 1b	Case 2a and 2b	Case 3a and 3b
Reactor number	-	4	12	8
Storage capacity	kg	31 665	26 915	28 398
Elec. consumption	MWe	326	277	292
Capital	USD million	2 345	2 127	2 197
O&M	USD million/year	353/464	122/150	128/158

Finally, the estimated costs of hydrogen are given in Table 6.26.

Table 6.26: **VHTR hydrogen plant condition and hydrogen cost**

		Case 1a	Case 1b	Case 2a	Case 2b	Case 3a	Case 3b
Reactor number	-	4	4	12	12	8	8
Hydrogen production	Ton/year	317 766	317 766	270 101	270 101	284 980	284 980
Electricity required	MWe	413.9	413.9	331.4	331	1 931.7	1 932
Heat required	MWth	2 400	2 400	2 040	2 040	-	-
H2 plant construction cost*	USD million	5 663	5 663	5 129	5 129	4 346	4 346
Electricity	USD/kg	1.17	1.61	0.31	0.43	1.71	2.40
Heat	USD/kg	1.24	1.59	1.16	1.51	-	-
H_2 plant capital**	USD/kg	0.55	0.55	0.58	0.58	0.51	0.51
H_2 plant O&M	USD/kg	0.19	0.19	0.21	0.21	0.24	0.24
Total (H_2 production)	**USD/kg**	**3.14**	**3.94**	**2.26**	**2.73**	**2.46**	**3.14**
Liquefaction	USD/kg	1.30	1.65	0.65	0.75	0.64	0.75
Total (H_2 production and Liquefaction)	**USD/kg**	**4.44**	**5.58**	**2.91**	**3.49**	**3.10**	**3.89**

* Included replacement cost during plant life.

** Included decommissioning cost (10% of capital).

Hydrogen cost is the lowest in Case 2. Seen from the detail in the table, the cost advantage is attributed to the ability in Case 2 to cogenerate the electricity and heat required by the hydrogen production at the lowest combined price compared to the other cases. Such a cost advantage is achieved despite the fact that its hydrogen plant costs are the highest due to lower economies of scale for hydrogen.

Contribution of CO_2 emission reduction by VHTR hydrogen

A recently completed study by the JAEA shows the contribution of VHTR cogeneration to meet the demands of hydrogen in various economic sectors in Japan (JAEA, 2016).

Forecasts for hydrogen demand in Japan are summarised in Table 6.27, with transportation, industries and residential, power generation, and steelmaking all considered hydrogen consumers. The references in the table identify the sources used in the forecast.

Table 6.27: **Future hydrogen demand in Japan**

	2030	2040	2050
Transportation (fuel cell vehicles)	56	169	330
Industries and residential (fixed FC)	15	146	429
Power generation (H_2 fired)	0	923	1 167
Steelmaking	0	0	314
Total	**165**	**1 332**	**2 240**

Source: IEEJ (2014b).

(1) Transportation

Fuel cell vehicles are expected to replace current internal combustion engine passenger cars, cargo cars and buses (except kei cars) by 2050 as follows (IEEJ, 2014b):

- 2025: begin to spread (10% of new car sales);
- 2040: 19% of total cars (50% of new car sales);
- 2050: 40% of total cars (100% of new car sales).

Hydrogen demand is then estimated based on assumptions of average travel distance, tank-to-wheel fuel efficiency and the number of fuel cell vehicles.

(2) Industrial and residential sectors

These sectors currently use stationary fuel cells that are fuelled by hydrogen produced from natural gas or city gas. However, CO_2-free hydrogen should be used in the future to meet the target of GHG reductions. Forecasts for the spread of CO_2-free hydrogen fuel cell (H_2FC) are outlined as follows:

- 2025: H_2FC begin to spread;
- 2040: 18% of total fixed fuel cell capacity;
- 2050: 52% of total fixed fuel cell capacity.

Hydrogen demand is then calculated considering the power generation efficiency of the fuel cell system and the power generation share of H_2FC units in the industrial and residential sectors.

(3) Power generation

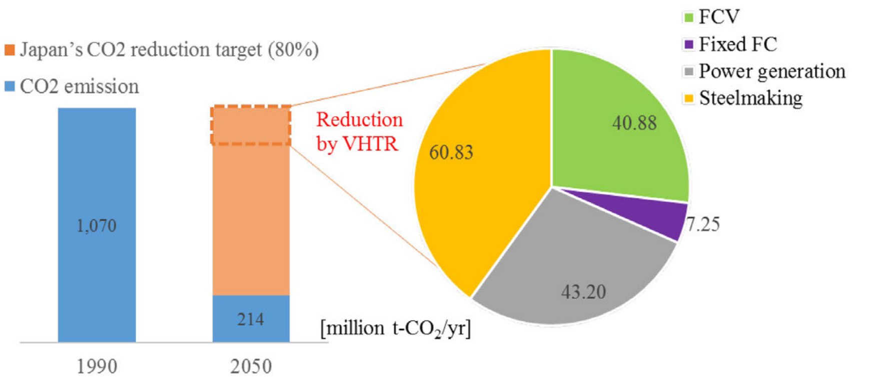
As for power generation, hydrogen power generation is expected to be commercialised after 2030 and rapidly spread to replace fossil fuel-fired plants and nuclear power plants (light water reactor, LWR) (IEEJ, 2014b). On the other hand, the Agency for Natural Resources and Energy in the Ministry of Economy, Trade and Industry of Japan has stated that nuclear power will meet 20-22% of total domestic electricity demand in 2030 (METI, 2015b). It is assumed that nuclear power will generate 20% of total national electricity demand even after 2030 and that hydrogen power generation will supply 27% of total electricity demand in 2050. As shown in Table 6.27, power generation is forecast to account for about 50% of total hydrogen demand in 2050.

(4) Steelmaking

The steelmaking industry is expected to use hydrogen in direct reduction process (Yan and Hino, 2011). The conventional process of direct reduction consumes natural gas. It is assumed that this process will use commercially developed hydrogen by 2050. Hydrogen is estimated to be used to 27% of total steel production in Japan in 2050.

As for the VHTR's contribution to hydrogen supply, the JAEA estimated that it will reach 40% of Japan's hydrogen demands in 2050. Figure 6.33 shows CO_2 reductions driven by VHTR hydrogen supply. Total VHTR hydrogen could reach 152.17 million t-CO_2/year in 2050, accounting for as much as 17% of the country's CO_2 reduction target. A total of 48 VHTR plants would be required, with each plant containing four 600 MWt reactor units.

Figure 6.33: **CO_2 reduction contribution by VHTR hydrogen in Japan**



Source: IEEJ (2014b).

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6.7. Application of SMART for nuclear cogeneration in a global low-carbon energy environment (Korea)

6.7.1. *Introduction*

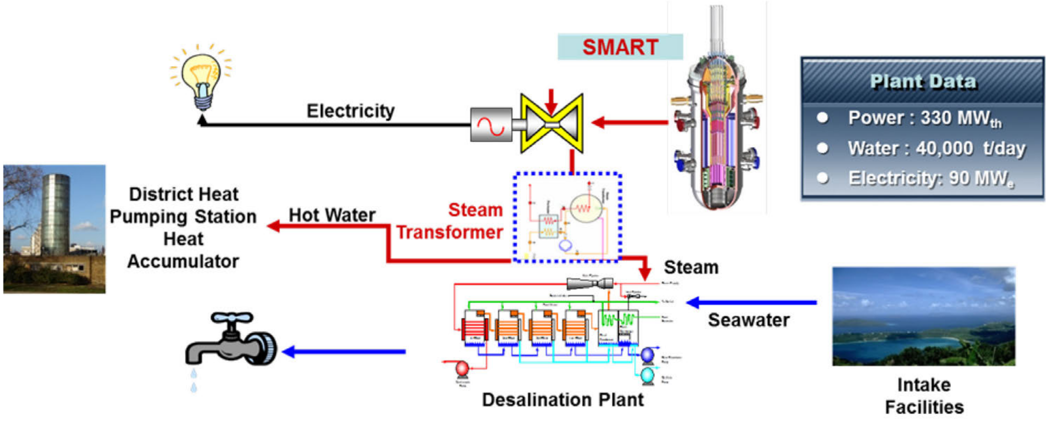
Achieving clean energy is central to the global effort to decarbonise the economy. The fossil fuels used for process heat applications such as water desalination and district heating and in refineries and petrochemical plants including electricity generation are a major contributor to global warming through carbon emissions. Nuclear energy is an essential part of a clean energy strategy to cope with climate change and ultimately secure decarbonisation with affordable risks and expense. Small modular reactors (SMRs, less than 300 MWe) could fit into the future energy mix and the long-term plans for decarbonisation; SMRs offer a potentially attractive nuclear energy option for process heat applications in addition to electrical power generation, based on their inherent, passive safety features. SMRs can be considered an alternative to large nuclear power plants or a complementary option.

Various advanced types of SMRs are under development worldwide, and some are ready for construction. The System-integrated Modular Advanced Reactor (SMART) is one of these advanced SMRs readily deployable for nuclear cogeneration purposes. With the support of industrial partners, the Korea Atomic Energy Research Institute (KAERI) has been developing the SMART since the late 1990s. The SMART is an advanced integral PWR (iPWR) with an electrical power output of 100 MW from 330 MW of thermal input. The SMART adopts advanced design features to enhance safety, reliability and plant economics. The advanced design features and technology implemented in the SMART were verified and validated during the Standard Design Approval review by the Korean regulatory authority, the Korean Nuclear Safety and Safeguard Commission (NSSC), from 2010 to 2012. The Standard Design Approval for the SMART was officially issued in July 2012. Following the signing of the Memorandum of Understanding for co-operation on SMART technology between the governments of Korea and Saudi Arabia in 2015, KAERI and K.A.CARE of Saudi Arabia entered an agreement for pre-project engineering (PPE) to deploy multiple units of the SMART in Saudi Arabia for nuclear cogeneration. Through the three-year SMART PPE project, a Saudi-specific, optimised engineering design will be developed and implemented into the first two units to be constructed in Saudi Arabia.

6.7.2. *Non-electrical applications of SMART*

The SMART has multipurpose applications, for electricity generation, seawater desalination, district heating, process heat for industries, and energy for small or isolated grids. The SMART has a unit output that is sufficient to meet the demands of electricity and, fresh water for a city of approximately 100 000 people or hot water for district heating. The SMART application for nuclear cogeneration is schematically shown in Figure 6.34.

Figure 6.34: **Configuration of the SMART's application for nuclear cogeneration**

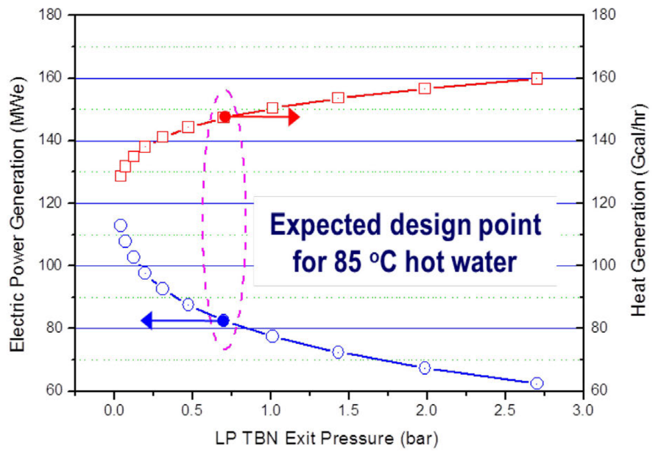


Source: Sung-Kyun Zee (2018).

For non-electrical applications, the system design requirements, design parameters and optimal combination of process heat production for desalination or district heating have been set up for typical reference cases.

For district heating, the SMART can supply 147 Gcal/h of heat to the local area heating grid as well as 82 MWe of electricity. The supply of electricity and 85°C of hot water is sufficient to meet the demands of 100 000 people by Korean standards.

Figure 6.35: **Balanced power output of SMART for district heating**



6.7.3. *General design description (KAERI, 2012 and 2016)*

Design philosophy

The SMART's design adopts an integrated primary system, modularisation and advanced passive safety system to provide safety, reliability and affordability. Its safety performance is assured by deploying full passive safety systems together with severe accident mitigation features. The passive safety features rely on gravity and natural convection and require no active controls or operator intervention to cope with malfunctions and safety events. Improvements in the economics of larger reactors is achieved through system simplification, in-factory fabrication, reduction of construction time and high plant availability. The advanced design features of the SMART include in-vessel pressuriser, integrated steam generators and the horizontally mounted canned motor pumps. Figure 6.36 shows the SMART reactor system's configuration.

Figure 6.36: **Reactor system configuration of the SMART**

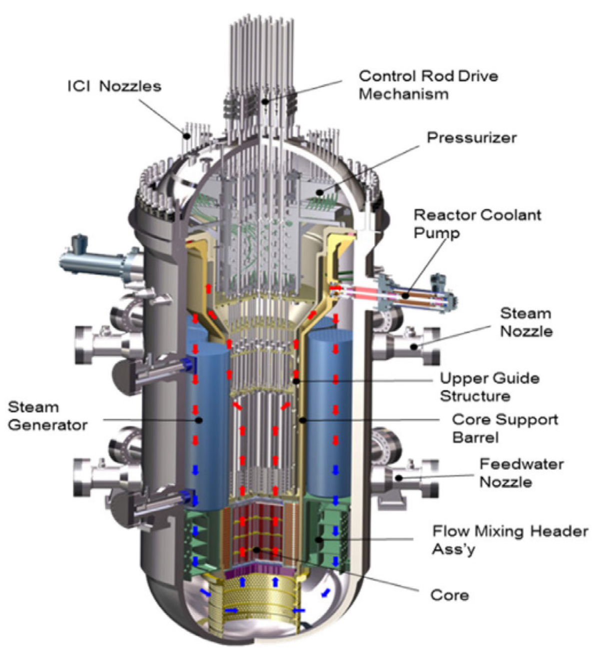


Table 6.28: **Major technical parameters of the SMART**

Parameter	Value
Technology developer:	KAERI
Country of origin:	Korea
Reactor type:	Integral PWR
Electrical capacity (MWe):	100
Thermal capacity (MWth):	330
Expected availability factor (%):	> 90
Design life (years):	60
Plant footprint (m^2):	90 000
Coolant/moderator:	Light water
Primary circulation:	Forced circulation
Number of reactor coolant pump	4 (horizontally mounted on the reactor vessel)
System pressure (MPa):	15
Core inlet/exit temperatures (°C)	296/323
Main reactivity control mechanism:	Control rod driving mechanisms and soluble boron
Reactor pressurised vessel height (m):	18.5
Reactor pressurised vessel diameter (m):	6.5
Module weight (metric ton)	840 (w/o coolant)/1 500 (w coolant)
Configuration of reactor coolant system:	Integrated
Power conversion process:	Indirect Rankine Cycle
Fuel type/assembly array:	UO_2 pellet/17 x 17 square
Fuel assembly active length (m):	2
Number of fuel assemblies:	57
Fuel enrichment (w/o):	< 5
Fuel burnup (GWd/ton):	< 60
Fuel cycle (months):	36
Cogeneration capability:	Yes
Approach to engineered safety systems	Passive
Number of safety trains:	4
Refuelling outage (days):	45
Distinguishing features:	Coupling with desalination and process heat application, integrated primary system, passive heat removal by natural circulation in case of emergency condition.
Modules per plant:	1
Target construction duration (months):	36
Seismic design:	> 0.18 g automatic shutdown
Predicted core damage frequency:	2E-7/reactor year (internal events)
Design status:	Licensed/certified (standard design approval)

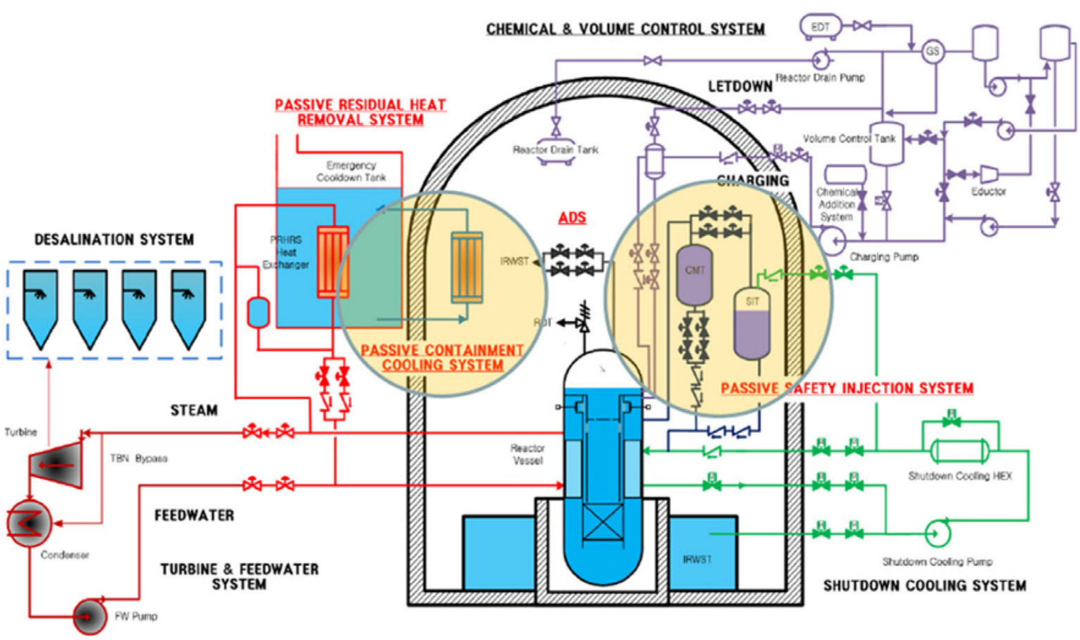
Engineered safety system approach and configuration

The SMART has passive safety features to cope with abnormal operating occurrences and postulated design basis accidents, and severe accidents with core melts. The passive safety system is being developed to maintain a safe shutdown condition following design basis accidents such as loss-of-coolant accident (LOCA) and non-LOCA transient events without AC power or operator actions. All the active safety features are being substituted with passive systems, eliminating the necessity for emergency power by emergency diesel generator or operator actions for at least the initial period of 72 hours. The engineered safety system of the SMART is shown in Figure 6.37.

Decay heat removal system

After the reactor is shut down, when the normal decay heat removal mechanism utilising the secondary system is not operable for any reason, the passive residual heat removal system (PRHRS) brings the reactor coolant system to the safe shutdown condition within 36 hours after accident initiation and maintains the safe shutdown condition for at least another 36 hours. Therefore, the safety function of this system operates for 72 hours without any corrective action by the operator for the postulated design basis accidents. The safety function of the PRHRS is maintained continuously for a long-term period when the emergency cooling tank (ECT) is replenished periodically. The PRHRS consists of four independent trains with a 33.3% capacity each, and each train is composed of an ECT, a heat exchanger and a make-up tank. In the design of the PRHRS, the possibility of loss of one train by a single failure is eliminated. Three out of four trains are enough to remove the residual heat after an accident.

Figure 6.37: **Engineered safety system of the SMART**



Plant safety and operational performances

The SMART utilises advanced online digital monitoring and protection systems that increase system availability and operational flexibility. The adoption of advanced man-machine interface technology leads to a reduction in human errors and to a compact and effective control room design with minimised staff requirements. The availability factor predicted for the SMART plant is greater than 90%, and the predicted occurrence of an unplanned automatic scram event is less than one per year. Design of the helically coiled steam generator is optimised to accommodate the in-service inspection requirements. Reactor head assembly including pressuriser is designed to be fully inspectable during the maintenance period.

The load follow operations of the SMART is simpler than that of a large PWR since only the single bank movement and small insertion limit is required for control. The SMART is suitable for load-following operations because a relatively small reactivity change is required for the power change due to the minimised coolant temperature change during power manoeuvring, and rapid damping of xenon oscillation due to the small core size. The SMART is capable of daily load-following operation by the lead bank movement only without any change of soluble boron.

6.7.4. *Evaluation for the optimised desalination model coupled with SMART system*

Studies have been performed to evaluate the optimised desalination model to interface with the SMART plant for nuclear cogeneration for seawater desalination. It was decided that having four units of the multi-effect distillation type with a thermo-compressor (MED-TVC), each of which has 10 000 tonne/day capacity, was the proper coupling option to satisfy both technical and economic factors. However, from the early 2000s, the reverse osmosis desalination plant came to the fore in the seawater desalination market with the advantage of low energy consumption. Furthermore, the reverse osmosis membrane performance was improved and its price dropped due to mass production. This competitiveness of the reverse osmosis model compared with the conventional thermal one is expected to grow with time.

Recent investigations into the optimal desalination model for the SMART system also recommended a hybrid type with the MED-TVC and the reverse osmosis system based on the following qualitative assessments:

(1) Previous studies did not consider high-quality fresh water required by the plant itself. In fact, the plant requires high-quality fresh water for the make-up and component cooling. The required water quality for plant use can be satisfied by a thermal desalination plant.

(2) Since the reverse osmosis plant has a cost advantage over the MED-TVC type, a hybrid model of desalination is recommended when considering the required desalination capacity. The blending of fresh waters from the MED-TVC (lower than 25 ppm) and reverse osmosis (~200-400 ppm) can meet the requirements for potable water. For portable water, the reverse osmosis plant is sufficient to operate in single stage, which reduces the operating cost of the reverse osmosis system.

(3) Regardless of the SMART plant's availability, the reverse osmosis system can produce fresh water continuously by utilising off-site power.

(4) It may be necessary to control the temperature of the seawater to improve the water production rate of the reverse osmosis system in winter. This can be achieved by utilising the hot brine discharged from the MED-TVC units without additional cost.

(5) A hybrid plant with two desalination types has an advantage in terms of sustained water supply in case any one type is out of service.

(6) The stand-by reverse osmosis system can accommodate excess electricity generated by the SMART plant when the grid load demand decreases. This will further improve the SMART plant's efficiency.

The assessment led to the recommendation of a desalination model coupled with the SMART plant with the following arrangement: (1) two MED-TVC units with each capacity of 10 000 m^3/day, (2) four reverse osmosis units with each capacity of 5 000 m^3/day, and (3) two stand-by reverse osmosis units with each capacity of 5 000 m^3/day.

6.7.5. *Licensing status of SMART*

The SMART Standard Design Approval (SDA) licensing was initiated in early 2010, when the Korean regulatory agency (Korea Institute of Nuclear Safety, KINS) started the Pre-application Review process. Through this year-long review, the SMART design approach, features and system descriptions were presented in a document and reviewed by the regulatory body. The review outcomes, including about 800 Q&As, were utilised in preparation of the SDA application material. The application for the SDA with backup documents was officially submitted to the regulatory authority on 30 December 2010. As specified by regulations, the Standard Safety Analysis Report (SSAR), Certified Design Material (CDM), Emergency Operating Guidelines (EOG) and the related documents were provided for regulatory review and approval. Nearly 2 000 technical questions were officially recorded and resolved during the SDA review process. Consequently, the Korean Nuclear Safety and Safeguard Commission (NSSC) officially issued the SMART Standard Design Approval on 4 July 2012. The additional design modifications and improvements made thereafter, with respect to the passive safety features, were validated through a four-year project of safety improvement and validation tests completed at the end of 2015. The licensing review of these additional design features will be processed as a part of a construction permit application for the upcoming SMART deployment.

6.7.6. *Scoping assessment of the economics of SMART nuclear cogeneration plant*

A scoping economic analysis was performed to develop a business case for the SMART nuclear cogeneration plant consisting of a single 330 MWt SMART coupled with a hybrid type desalination system of 40 000 m^3/day capacity, as described in the previous section. In general, the specific costs of integrated co-production plants like the SMART for potable water and electricity depends very much on the capacities of the power plant and desalination plant, the production ratio between electricity and water, their variations throughout the year, and local conditions at the site. Economic analysis for generation plants often requires well suited models to handle various financial options and cost parameters accurately. Though the SMART plant cost estimation is based on the actual equipment list and specifications generated from the design data for the SDA project and the initial quotation price from various equipment/service suppliers and vendors, this scoping economic assessment utilised certain assumptions, including the anticipated reactor performance and efficiency, financing, and construction period. The assumptions used are summarised in Table 6.29. The DEEP5.0 software developed by the IAEA was utilised for the scoping economic assessment, since it is an open code system that is well verified and documented for the mentioned purpose (IAEA, 2013).

Table 6.29: **Input parameters for economic assessment**

Item		Remarks
Construction period	50 months	
Plant capacity	103 MWe	Gross electric output
Plant operation (nuclear/desalination)	50/20 years	Designed lifetime: 60 years
Operational availability factor	93%	
Total capacity of desalination plant	40 000 m^3/day	MED-TVC: 20 000 m^3/day Reverse osmosis: 20 000 m^3/day
Cooling water temperature (°C)	Av. 28	20~35 (°C)
Seawater total dissolved solids (ppm)	40 000	
Fuel cost	USD 8/MWh	
Specific O&M cost	USD 20/MWh	

The designed steam pressure and temperature were estimated to be at 5.2 MPa and 298°C generating gross electric output of 103 MWe. The adjusted plant heat balance calculation by DEEP5.0 showed that the electricity throughput to the grid was about 95 MWe, with 5 MWe for house-load and 3 MWe for desalination units. The levelised cost of energy and the water production cost for the two specific plant construction costs are summarised in Table 6.30.

Table 6.30: **Levelised power and water costs**

Specific plant construction cost (USD/kWe)	Levelised cost of energy (USD/MWh)	Water cost (USD/m^3)
8 000	94.5	0.95
10 000	111.3	1.02

The IRR after taxation and NPV with power and water selling prices of 12 US cents/kWh and USD 1.5/m^3, respectively, are analysed as shown in Table 6.31.

Table 6.31: **Summary of financial analysis results for SMART hybrid desalination plant**

Specific plant construction cost (USD/kWe)	IRR	NPV @10% expected equity return
8 000	10% (after-tax) 11% (pre-tax)	USD 114 M
10 000	9% (after-tax) 10% (pre-tax)	USD 29 M

Some financial assumptions with the above specific plant construction costs were as shown in Table 6.32 (National Technical Laboratory, 2011).

Table 6.32: **Financial structure parameters**

Parameter	Value
Discount rate/interest rate	5.5%/5.5%
Corporation tax rate	20%
Depreciation	20 years, straight line
Equity/debt	55%/45%

For carbon tax calculations, DEEP5.0 utilises specific CO_2 emission levels for combined-cycle and nuclear units of 0.4 kg/kWh and 0.029 kg/kWh, respectively. The annual CO_2 emission savings from a single unit operation of a 100 MWe SMART replacing a combined-cycle plant with similar capacity are ~292 500 ton, giving a total of ~1.5 x 10^7 tons of emission savings over the plant lifetime operation.

6.7.7. *Deployment plan for SMART nuclear cogeneration plant*

Following the memorandum of understanding between the governments of Korea and Saudi Arabia on the SMART partnership and human capacity build-up signed in March 2015, the Korea Atomic Energy Research Institute (KAERI) and the King Abdullah City for Atomic and Renewable Energy (K.A. CARE) agreed to pursue deployment of multiple SMART plants in Saudi Arabia. As a first phase in the SMART co-operation, the SMART PPE (pre-project engineering) agreement was signed in September 2015. For the next three years until the end of 2018, the SMART PPE project was set to update the engineering level of the SMART plant design in preparation of the deployment of the SMART plants in Saudi Arabia. Specifically, site conditions and information were to be reflected in the engineering design, including design optimisation of the balance of plant (BOP). Through the SMART PPE project, a full licensing application document, including the safety analysis report, will be generated for the construction permit of SMART plants in Saudi Arabia.

6.7.8. *Conclusion*

The SMART is an advanced SMR that has been developed for nuclear cogeneration applications. Through the Standard Design Approval licensing process, the design and safety of the SMART were reviewed and validated. As a result, the Korean regulatory authority issued the SDA in 2012. Design improvements and modifications for passive safety features were further elaborated and validated through an extensive validation programme completed in 2015. The preliminary assessment shows that the SMART plant coupled with a hybrid desalination system is technically and economically viable. The deployment of a SMART nuclear cogeneration plant is being realised through a pre-project engineering agreement between KAERI and K.A. CARE signed in 2015. By 2024, the first unit of the SMART nuclear cogeneration plant will be constructed in Saudi Arabia after completion of the SMART pre-project engineering by 2018.

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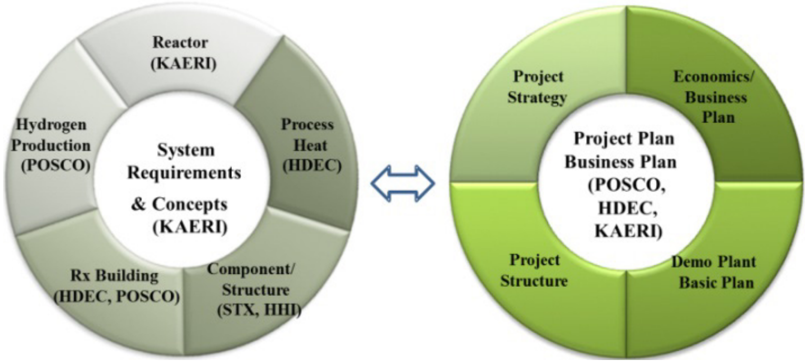
6.8. Study on nuclear process heat and hydrogen production in Korea

6.8.1. *Introduction*

Fossil fuels provide 85% of the primary energy consumption in Korea as of 2012, and 96% of them are imported. The industry and transportation sectors account for about 70% of national consumption of fossil fuels and for 90% of national carbon dioxide emission. Besides, energy consumption and carbon dioxide emissions in these sectors are increasing at rates of 3.1% and 4.5%, respectively. Therefore, to decrease dependence on fossil fuels to support climate change targets and to reduce energy imports to improve energy security, the Korean government has made it a priority to develop low-carbon energy technologies for industry and transportation.

In order to expand the use of nuclear energy to non-electricity sectors, the Korean government in 2008 established a long-term technology roadmap to demonstrate hydrogen production on a massive scale using very high temperature gas-cooled reactors (VHTRs). In 2011, the government prescribed a review of an industrial process heat application of VHTR as an intermediate step to reaching the final goal of producing hydrogen. To apply for a grant for a large national project in accordance with government policy, the Korea Atomic Energy Research Institute (KAERI) developed with the support of industrial partners the (V)HTR system concepts and a long-term plan to demonstrate them for further commercialisation. Under the leadership of KAERI, the potential end users and design/construction providers, including POSCO, Hyundai Engineering & Construction (HDEC), Hyundai Heavy Industries (HHI), Hyundai Engineering (HEC) and STX Heavy Industries (SHI), invested and became involved according to their respective expertise, as shown in Figure 6.38.

Figure 6.38: **Role contributors for planning of VHTR demonstration**



Source: KAERI (2018).

6.8.2. *VHTR system concepts for process heat and hydrogen*

The VHTR is considered the best nuclear technology to replace fossil fuels in industry and transportation due to its intrinsic passive safety and varied heat availabilities. Two (V)HTR system concepts with different technical maturities have been developed: the NuH2-PHS system for cogeneration of electricity and process heat required for an industrial complex; and the NuH2-HPS system for hydrogen production required for the oil-refinery industry, iron industry and transportation in the forthcoming hydrogen economy era.

Design concepts have been developed for the two systems, including the design and performance requirements, the conceptual design of the reactor and plant systems, the layout and optimised operational parameters, the conceptual design and manufacturability/ procurability assessment of major components and materials, the conceptual design and seismic analysis of the subterranean reactor building, and the radioactive waste management and protection.

Design and performance requirements

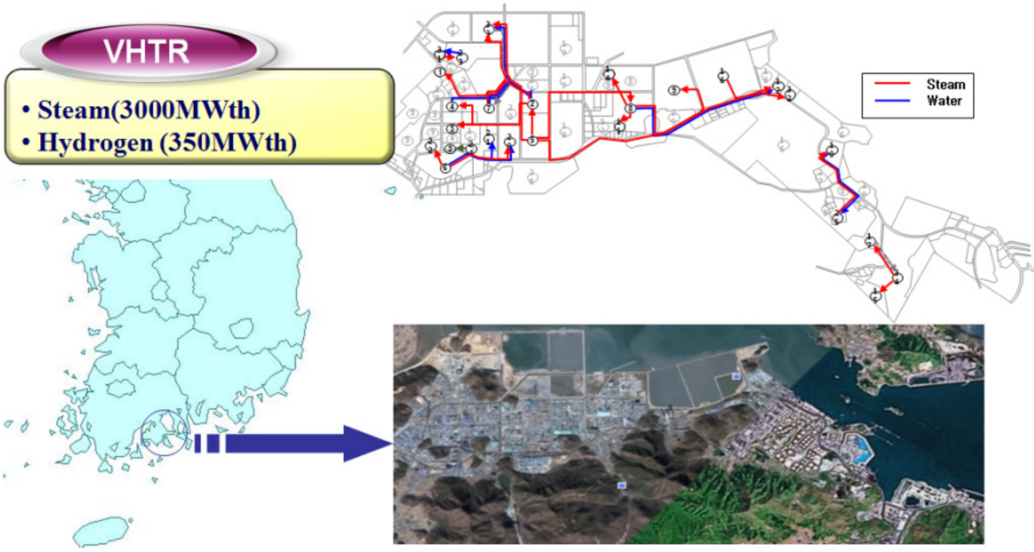
The Design and Performance Requirements Documents (DPRD) for the two systems were developed based on the demand and market analysis for each system. The DPRD, which is the highest-level document of system design, consists of four components: institutional requirements, plant-level performance and requirements, plant performance descriptions, and the subsystem-level performance and requirements of each subsystem. Each of the components has several detailed subcategories which, as a whole, are either safety-related to ensure licensing in Korea or performance-related to protect investments in the Korean market. Various design documents, including DPRDs and their references such as related domestic laws and regulations and the Code of Federal Regulations (CFR) Title 10, have been stored and managed as a database so that their history may be traced.

Concept of process heat generation system

Primary target heat markets

In Table 6.33, the overall statistics of process heat supply are presented for the two representative industrial complexes that are most appropriate for nuclear heat supply because they take about 60% of the national process heat supply in Korea. About 90% of process heat for the two complexes is currently being provided through steam or hot water pipe lines (for example, shown in Figure 6.39) at different temperatures connected to CHP plants and heat-only boilers operated by several regional heat suppliers whose sales are somewhat institutionally guaranteed as compensation for infrastructure investment. Only the remaining 10% is the waste heat of incinerators or power plants located outside but near the complexes.

Figure 6.39: **Process heat supply network in Yeosu industrial complex**



Source: KAERI (2015).

This is a very favourable condition for nuclear heat supply because ageing fossil-fuelled boilers can be sequentially replaced by nuclear boilers. Table 6.34 shows the status of high-temperature steam production in the Yeosu industrial complex, which has about 40% of the national heat market share. As shown in the table, most heat is provided as steam pressurised to more than 20 bar.

Table 6.33: **Status of process heat supply to industrial complexes**

Region	Heat production (Gcal/year, as of the end of 2012)					Total	Regional share (%)
	Regional production				External supply		
	CHP	Heat only	Plant-own Process heat	Sub-total			
Yeosu	9 588 874	7 208 750	0	16 797 624	169 805	16 967 429	37.6
Ulsan	7 318 026	324 386	0	7 642 412	1 439 799	9 082 211	20.1
Others	14 448 163	849 772	3 115 517	18 413 452	672 587	19 086 039	42.3
Total	31 355 063	8 382 908	3 115 517	42 853 488	2 282 191	45 135 679	100
Share (%)	69.5	18.6	6.9	94.9	5.1	100	

Table 6.34: **Status of steam production in Yeosu industrial complex**

Units	Steam production (in 2012)				By the fuel used				
	Pressure			Total	Coal	Energy-use oils	By-products	Heat recovery	Total
	High (>40 bar)	Medium (>20 bar)	Low (<20 bar)						
T/hour	4 716	1 214	371	6 301	1 305	1 713	1 210	2 074	6 302
kT/year	37 355	9 619	2 941	49 915	10 336	13 567	9 584	16 428	49 915
kTOE	2 013	518	159	2 690	557	731	517	885	2 690
%	74.8	19.3	5.9	100	20.7	27.2	19.2	32.9	100

System layout

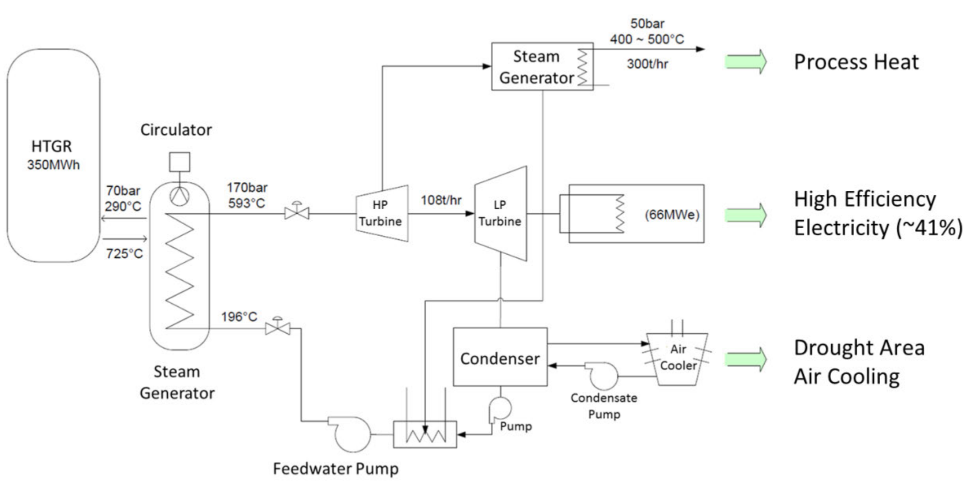
The Nu2-PHS plant size was selected in consideration of the high-temperature steam and electricity demand and market outlook in the two industrial complexes and the economies of scale of the plant. The unit plant is composed of four independent modules, each of which is shown in Figure 6.40 and consists of a 350 MWth block-type HTGR whose major design parameters are listed in Table 6.35, a Rankine-cycle electricity generation system, and a high-temperature steam supply system. Because the outlet temperature is relatively low, the reactor vessel and the steam generator can be fabricated using high-temperature technologies and materials available in the market. A circulator and a steam generator with spiral tubes are integrated into the steam generator pressurised vessel. The performance analysis with the boundary conditions of operating parameters shown in the figure confirmed that the plant can generate electricity and steam with up to 50 bar and 500ºC. A Nu2-PHS system can generate 144.7 MWe electricity with 41% efficiency in all-electric mode and 237.6 MWth process heat with 68% efficiency in turbine bypass mode.

Noticing that the process heat supplied by the existing CHP and heat-only plants is replaceable by the nuclear heat, the number of 350 MWth Nu2-PHS systems required to supply process heat was estimated to be 7.1 for the Yeosu industrial complex and 3.2 for Ulsan. If more extended, 15.4 Nu2-PHS systems are needed to provide the total 36 329 208 GCal/year of process heat in the six industrial complexes whose replaceable heat is comparable to or greater than the capacity of a single Nu2-PHS system.

Table 6.35: **Major reactor parameters of NuH2-PHS process heat system**

Reactor parameter	Value
Thermal power	350 MWth
Inlet/outlet temperature	290ºC/725ºC
Pressure	7 MPa
Equivalent inner/outer active core diameter	1.65 m/3.5 m
Active core height	7.93 m
Lifetime	60 year
Enrichment of uranium	15.5%
Number of fuel columns	66
Number of fuel blocks per column	9
Refuelling period/number of batches	1.5 year/2

Figure 6.40: **NuH2-PHS process heat system**



Source: KAERI (2015).

Design and performance analysis of reactor system

Neutronic, thermo-fluidic, safety analyses have been performed for the reactor system of the NuH2-PHS. The core neutronic analysis confirmed that the reactor core can provide the required fission power of 350 MWth to the reactor cooling system for 500 days per refuelling cycle, while satisfying related safety limits. The core thermo-fluidic analysis also showed that the safety criteria and the performance requirements are met during steady-state operation, except for the maximum fuel temperature. The maximum fuel temperature slightly exceeds the limit of 1 200°C by 11°C but it can be improved through subsequent in-depth designs without great efforts. The low- and high-pressure conduction cooling events which are the most serious and limiting accidents for this type of reactor were analysed and the resulting maximum temperatures at different positions of the reactor were estimated to be within their acceptable range.

Design and performance analysis of process heat system

A study was undertaken to draw the layout appropriate for the NuH2-PHS cogeneration system and to analyse its performance. In spite of some loss in efficiency, the multiple-extraction condensing turbine layout was selected because it can relatively easily produce electricity and different types of heat with control of the share between product types to satisfy the needs of the representative industrial complexes as shown in Table 6.34.

A. High-temperature steam at 500°C and 50 bar

The steam at 582.6°C and 158.1 bar is extracted at a point between the exit of the steam generator and the entrance of the turbine and cooled and depressurised to meet this condition. Assuming that steam is produced at a rate of 300 t/hour with electricity, a simulation showed that this layout provides process heat of 269.0 MWth and electricity of 46.87 MWe including in-house consumption of 8.93 MWe by receiving 350.5 MWth from the steam generator and 52.39 MWth from three feed-water heaters. The overall CHP efficiency is 76.2%. A sensitivity study on the flow rate of process heat confirms our expectation of a linear increase of overall CHP efficiency with the flow rate increasing due to higher heat efficiency than electricity.

B. Intermediate temperature steam 400°C and 50 bar

After another sensitivity study to find the extraction position that yields maximum efficiency, extraction was determined to be made between the high-pressure turbine and the low-pressure turbine where cooling is not required. Again assuming that the flow rate of steam is 300 t/hr, this layout produces process heat of 249.3 MWth and electricity of 65.98 MWe including in-house consumption of 9.12 MWe by receiving 350.5 MWth from the steam generator and 54.52 MWth from three feed-water heaters. The overall CHP efficiency is 75.6%.

C. Low-temperature steam or hot water at < 300°C and < 40 bar

Extraction is considered to be made during expansion in the low-pressure turbine. This layout and even various combinations of individual heat types and electricity with their control logic will be investigated in further designs.

Concept of hydrogen generation system

Primary target hydrogen markets

Due to the advent of shale gas, hydrogen infrastructure delays and a global economic recession, it will take a significant amount of time to realise the hydrogen economy, which assumes the massive use of hydrogen in fuel cells for transport and distributed power generation. On the other hand, there is imminent hydrogen demand for hydrogen reduction steelmaking to replace carbon monoxide reduction steelmaking, which emits about two tonnes of carbon dioxide per one tonne of steel production.

Converter steel production in Korea was a total of 40 Mt/year in 2013. POSCO is a leading company in Korea and has developed the FINEX coal gas reduction process, which releases considerably less carbon dioxide and better fits the hydrogen reduction process. POSCO is also developing the FINEX hydrogen reduction process to reduce its carbon dioxide emissions which currently account for about 10% of national greenhouse gas emissions.

The Nu2-HPS system was supposed to provide massive hydrogen to the 2 Mt/year scale FINEX hydrogen reduction facility. (POSCO has three FINEX facilities: 0.6 Mt/year, 1.5 Mt/year, and 2 Mt/year) This facility requires 145.7 kT/year of hydrogen. POSCO can take additional advantage from water-splitting hydrogen production because it consumes 400 kNm^3/hour of oxygen in its factories. POSCO also consumes 3 GWe of electricity, of which 2 GWe is self-produced.

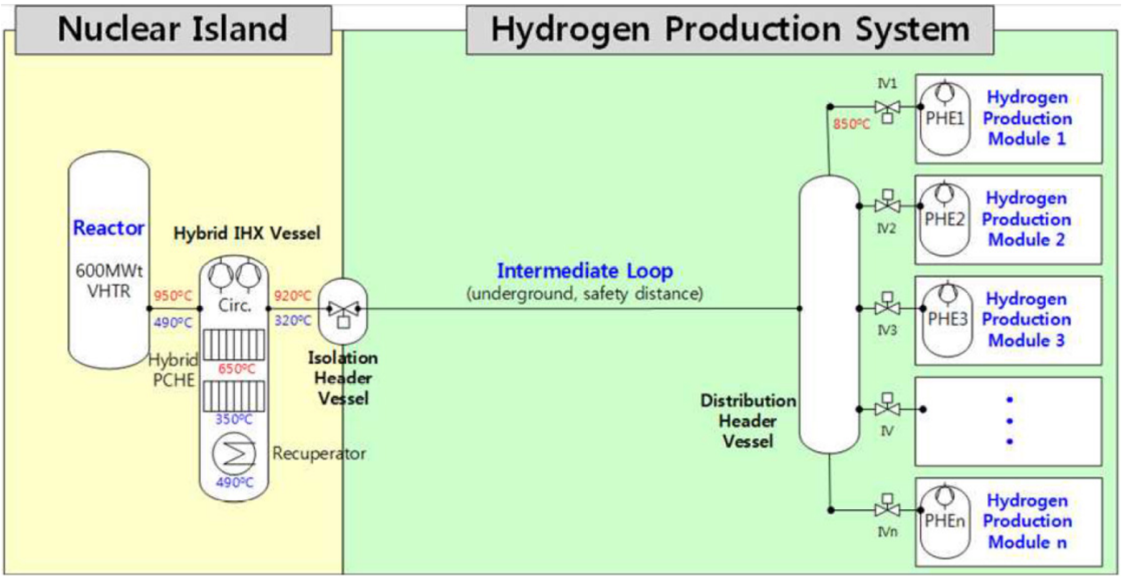
System layout

The NuH2-HPS plant size was designed to supply hydrogen required for the FINEX hydrogen reduction facility. The plant was also designed to cope with electricity demand for the facility and nearby factories. The unit plant is composed of three hydrogen production modules and one electricity generation module. A hydrogen production module consists of a 600 MWth block-type VHTR with the major design parameters listed in Table 6.36 and sulphur-iodine hydrogen production systems. The performance analysis estimated that each hydrogen production module can produce 60 kt/year of hydrogen. The electric module is a 600 MWth (V)HTR power plant with either a steam or gas turbine depending on its competitiveness and technical maturity.

The number of 600MWth Nu2-HPS systems required to supply hydrogen to the 2 Mt/year scale FINEX facility is estimated to be 2.4. Accordingly, POSCO's three FINEX facilities with 4.1 Mt/year capacity in total require 5.0 Nu2-HPS systems. Furthermore, if Korea's total yearly production of 40 Mt steel is completely produced by hydrogen reduction, 48.6 Nu2-HPS systems are needed.

Figure 6.41 shows schematically a single hydrogen production module. A hybrid intermediate heat exchanger, two circulators, and a recuperator are integrated into the intermediate heat exchanger pressurised vessel. The hybrid intermediate heat exchanger is composed of two printed circuit heat exchangers (PCHE): a high-temperature module made of A617 material for an operating range of 650~950ºC and a low-temperature module of Steel Use Stainless (SUS) for a range of 350~650ºC. Each sulphur-iodine module has 50 MWth capacity in consideration of maximum size of single chemical process and its optimum operational availability. The isolation header and the coaxial pipe-type intermediate helium loop provide a boundary and a safety distance between the reactor system and the hydrogen production system, respectively.

Figure 6.41: **Layout of single hydrogen production module**



Source: KAERI (2015).

Table 6.36: **Major reactor parameters of NuH2-HPS hydrogen system**

Reactor parameter	Value
Thermal power	600 MWth
Inlet/outlet temperature	490°C/950°C
Pressure	7 MPa
Equivalent inner/outer active core diameter	2.96 m/4.84 m
Active core height	7.93 m
Lifetime	60 year
Enrichment of uranium	15.5%
Number of fuel columns	102
Number of fuel blocks per column	9
Refuelling period/number of batches	1.5 year/3

Design and performance analysis of reactor system

For the reactor system of the NuH2-HPS, the neutronic and thermo-fluidic steady-state core analyses and the low-pressure conduction cooling transient analysis were performed. All the safety criteria and the performance requirements investigated in the analyses are satisfied. Due to the high core inlet temperature, the maximum reactor pressurised vessel temperature during the low-pressure conduction cooling event very slightly exceeds the limit of 538°C for SA508/533 steel by 2°C. However, the time during which it remained over the limit is almost negligible compared with the allowable time of 1 000 hours. This suggests the need to check whether the high core inlet temperature threatens the temperature limits for any of the major components in further designs.

Design and performance analysis of intermediate loop

Unlike the NuH2-PHS process heat system, the NuH2-HPS hydrogen system has an intermediate loop to provide the safety distance between the reactor system and the hydrogen production system. A series of system analyses was performed to select the optimal coolant gas, pipe diameter and safety distance. As for the coolant selection, argon, nitrogen, and their mixtures with helium were first filtered out among candidate coolant gases because of their high circulation work rate. Helium was finally selected over carbon dioxide due to the gain in heat transfer surface area reduction of the steam generator connected to the hydrogen system despite relatively small loss in circulation work.

The pipe diameter and the safety distance directly affect the hydrogen production economics. The circulation work rate was found to be more sensitive than predicted and to be inversely proportional to the square of the diameter. The analysis results of hydrogen explosion blasted from the hydrogen production side showed that the safety distance could be determined according to related regulations rather than the explosion impact. The optimum helium intermediate loop design was selected for the 350 MWth demonstration plant as in Table 6.37.

Table 6.37: **Optimum He intermediate loop parameters for 350 MWth NuH2-HPS hydrogen system**

Parameter	Value
Q transfer	350 MWth
Operation pressure	70 bar
Pipe diameter	171.23 cm
Hot stream temperature	920°C
Flow rate	146.60 kg/s
Pressure drop	~2 bar
Safety distance	100 m
Cold stream temperature	460°C

- Design and performance analysis of hydrogen system

It is premature to offer a reliable conceptual design of the commercial-scale sulphur-iodine hydrogen production system and its components because related technologies are still at a basic level. Only the numerical dynamics and efficiency analyses for the overall chemical process chart have been performed.

Assuming that the 950°C heat from the reactor is transferred to the 880°C steam with 90% efficiency to provide heat for the sulphur-iodine process, the NuH2-HPS hydrogen production system was estimated to be able to produce hydrogen at a rate of 78 000 Nm^3/hour (equivalent to 60 t/year) with 35.2% efficiency. A simulation using the commercial chemical process simulator PRO/II to estimate the accuracy of this in-house overall efficiency analysis resulted in a hydrogen production rate that was about 15% higher and only reconfirmed the prematurity of the current system.

Concepts of major components and buildings

- Components

A range of major components have been designed conceptually and their performances analysed. These components include the three pressurised vessels (the reactor vessel, the steam generator vessel, and the cross vessel connecting the reactor and the steam generator), the reactor cavity cooling system, the coolant duct, the steam generator, the circulator, the intermediate heat exchanger, the core internals including upper and lower plenums, and the fuel handling machine.

The manufacturability or procurability of the major components was also investigated. While the components and their materials were estimated to be mostly available in the domestic and international markets, the following remaining issues, including those related to the high-temperature materials for the hydrogen production system, were stressed.

1. By installing a thermal shield and a cooler to protect the reactor pressurised vessel from high temperatures, the LWR materials such as Mn-Mo-Ni-based low-alloy steel SA508 and SA533 can be used. Because the vessel is much larger than the LWR's, it may be considered to use high-temperature high-strength materials such as 9Cr-Mo or12Cr-Mo-based ferrite martensite steel to reduce weight. The supplier needs to secure a high-temperature material welding and forging technology.
2. A single helical tube in the steam generator is wound 11~12 times and is 97.6 m. Because the length of a tube that can be extruded is about 30 m, approximately four tubes must be welded together to make a single tube. The 33 mm pitch between tubes in the current design may not be wide enough for welding. A design with a wider tube pitch or with several shorter modular steam generators is rather realistic.
3. The supplier of high rpm He circulators shall ensure the He leak prevention design and the contamination-free large-scale electromagnetic bearing technology.
4. The flow-path etching and diffusion bonding technologies are essential for Alloy 617, a candidate material of PCHE-type high-temperature heat exchangers.
5. A control technology for the fuel handling machine should be demonstrated with high precision.
6. The American Society of Mechanical Engineers (ASME) code case for Alloy 800H, a candidate material of metallic core supports currently available for up to 650°C, and that for the above-mentioned Alloy 617, currently not available, should be extended to allow the full range of operating temperatures.
7. Designing the commercial-scale sulphur-iodine hydrogen production system and its components requires further development of related technologies.

- Buildings and facilities

Based on the experience of constructing the Korean standard PWRs, the requirements and layouts of the following buildings and facilities were developed and performance analyses, including seismic analyses, were carried out: the underground reactor building, the reactor auxiliary building, the electrical service building, the nuclear island cooling water system, the spent fuel cooling system, the shutdown cooling water system, the reactor service building, the operations centre and control room, the radioactive waste building, the plant cooling system, the remote shutdown building, the helium storage building, the nuclear island warehouse, and the fire pump house.

To store spent fuels, a silo-type dry storage was proposed and a safety analysis consisting of criticality, radiation shielding and heat release calculations was performed.

Concepts for radioactive waste management and reactor decommissioning

By reviewing and assessing various waste treatment and reactor decommissioning methods, the following were recommended:

1. Graphite waste may be incinerated in a fluidised bed with exhaust gas trapping after pulverising graphite into powder. This may encounter public resistance, although its release of C^{14} is far lower than that of a fossil fuel plant.
2. The chemical immersion method for graphite components and the electro polishing or gel and foam method for other metallic components are suitable for decontamination of components.

A delayed decommissioning starting at least a few years after permanent shutdown of the reactor is desirable. The starting time depends on the utilisation of land after decommissioning. Decommissioned radioactive waste is stored in the onsite interim concrete containers for more than ten years and then transported to the final disposal facility.

Economics of process heat and hydrogen systems

An economic analysis was performed in 2008 estimating the capital and operating costs of the commercial-scale nth-of-a-kind (NOAK) hydrogen production plant consisting of four modules of 600 MWth block-type VHGR with the outlet temperature of 950°C. The analysis was part of the national project to investigate infrastructures for the hydrogen economy (KEEI, 2008). The results of the study were comprehensively reviewed and updated for the commercial-scale NuH2 systems by reflecting progress in design and experience in construction of the Shin-Kori 3&4 and Shin-Ulchin 1&2 PWR units. In addition, the costs for radioactive waste management and decommissioning were also evaluated based on the relevant governmental notice (MOTIE, 2013). The resulting cost data were adjusted to constant prices in October 2014, corrected for the average producer price inflation in Korea for past values and for the assumed inflation of 3% per year for future values. The assumed composition of debt and equity in the total investment is 70:30 and the interest rate for the debt to be spent after exhausting equity is 6% including the risk premium.

It is noted that this analysis for the conceptual design is preliminary and will be refined in further design steps.

NuH2-PHS process heat system

A. Costs analysis

An economic analysis was made for the NOAK NuH2-PHS process heat plant consisting of four modules of 350 MWth block-type HTGR with 60 years lifetime. The plant, which produces only process heat without any electricity with 90% availability, is assumed to be located within 10 km of the fossil fuel plants to be replaced. Since Korea is mostly hills and small mountains, this 10 km distance is enough to provide a safety distance from the nuclear plant to the industrial facilities.

The direct capital costs of the main components evaluated for the 4 x 600 MWth plant in *Infrastructure Building for Materialization of Future a Hydrogen Economy* (KEEI, 2008) are scaled down for the 4 x 350 MWth plant by using the following capacity adjustment factor:

- $(350\text{ MWth}/600\text{ MWth})^{0.66} = 0.7007$.

Table 6.38: **Capital and operating costs of NOAK 4 x 350 MWth NuH2-PHS process heat system**

Capital costs (KRW million)			
1. Direct costs	1 320 549	3. Contingencies	139 553
Equipment costs	1 060 086	4. Steam piping costs	163 000
Installation costs	260 463	5. Interest	101 181
2. Indirect costs	230 039	Total capital costs	1 954 322
Operating costs per year (KRW million)			
1. Direct costs	65 423	Licensing	2 517
Labour	18 609	Insurance	2 315
Maintenance	2 791	3. Moderator graphite	1 957
Make-up materials (He, CR, others)	11 449	4. Fuel	65 280
Radwaste management	5 015	5. Water (raw material, cooling, etc.)	5 767
Spent fuel/moderator management	26 277	6. Electricity	36 101
Reactor technology support	1 281	Total net operating costs	197 610
2. Indirect costs	23 082	7. Decommissioning reserve	6 598
Indirect labour	2 369	8. Depreciation	30 886
Indirect operation (local outreach, etc.)	15 881	Total operating costs per year	235 094

B. Benefits analysis

The steam output was estimated to be 13 970 880 t/year at 29 kg/cm^2 and 240℃ with an assumption of 98% heat transfer efficiency. The process heat production cost when the plant starts production in 2029 after three years of modularised NOAK construction was estimated in October 2014 to be KRW 18 608 /t at constant prices.

The sale price of steam was estimated to be KRW 45 000/t, by averaging the following three basis values: (1) KRW 67 540/t, the steam generation price excluding facility costs produced by bunker-C oil purchased at the average market price of 2014; (2) KRW 27 560/t, the steam generation price including facility costs of 53.6% produced by coal purchased at the average market price of 2014; (3) and KRW 35 000/t, the sale price of steam generated by waste heat.

The IRR and the benefit-cost ratio (BCR) after taxation are estimated to be 20.10% and 1.79 (2.41 without tax), respectively. It can be concluded that the nuclear process heat production is a profitable business with a payback period of six years.

C. CO_2 emission reductions

Table 6.33 implies that the process heat replaceable by nuclear heat in the two representative industrial complexes in Korea is equivalent to 2 440 036 GCal/year (equivalent to 2 444 kTOE/year). Assuming that coal with a net-calorific-value based on the Intergovernmental Panel on Climate Change (IPCC) carbon emission factor of 1.059 tC/TOE (equivalently, 3.883 tCO_2/TOE) and bunker-C oil with the factor of 0.875 tC/TOE (equivalently, 3.208 tCO_2/TOE) are used for heat with a

40:60 share, the CO_2 emissions from heat generation are calculated to be 10.00 Mt/year (the steam production efficiency, which has a lot of variables, is assumed to be 85%). This amount of emissions can be avoided if nuclear replaces the fossil fuels. It should be noted that the CO_2 footprint of nuclear mostly caused by construction and decommissioning is almost negligible.

With the same assumption, nuclear energy can reduce the CO_2 emissions by 14.87 Mt/year if it replaces fossil fuels to produce process heat of 36 329 208 GCal/year, the total heat replaceable by nuclear in Korea.

Considering the 4 x 350 MWth NuH2-PHS process heat plant can provide 9 460 000 GCal/year of heat, this plant is estimated to reduce CO_2 emissions by 3.87 Mt/year.

NuH2-HPS hydrogen system

A. Cost analysis

An economic analysis was made for the NOAK 4 x 600 MWth NuH2-HPS hydrogen plant, which produces only hydrogen and no electricity. The sulphur-iodine hydrogen facility is assumed to have a 30-year lifespan and would have to be replaced once to cover the nuclear reactor's lifetime. Both hydrogen and oxygen produced by the sulphur-iodine facilities are transferred to the consumer facilities located within 20 km through pipelines, for price of KRW 1 billion per km per pipeline. Most of the other assumptions made for the economic analysis of the process heat system are retained for the hydrogen system.

Table 6.39: **Capital and operating costs of NOAK 4 x 600 MWth NuH2-HPS hydrogen system**

Capital costs (KRW million)			
1. Direct costs	2 355 107	3. Contingencies	248 470
Equipment costs	1 983 365	4. H_2 and O_2 piping costs	40 000
Installation costs	371 742	5. Electricity receiving facility	18 000
2. Indirect costs	405 677	6. Interest	169 312
		Total capital costs	3 236 565
Operating costs per year (KRW million)			
1. Direct costs	112 747	Indirect operation (local outreach, etc.)	22 665
Labour	19 548	Licensing	3 592
Maintenance	2 932	Insurance	3 305
Maintenance in chemical engineering	27 407	3. Moderator graphite	2 891
Make-up materials (He, I, CR, others)	17 647	4. Fuel	100 806
Radwaste management	7 158	5. Distilled water	1 429
Spent Fuel/Moderator Management	36 227	6. Electricity	167 793
Reactor technology support	1 829	Total net operating costs	418 611
2. Indirect costs	32 944	7. Decommissioning reserve	9 976
Indirect labour	3 382	8. Depreciation	51 121
		Total operating costs per year	479 708

B. Benefits analysis

The hydrogen output, which is estimated to be 240 000 t/year, is supplied to the POSCO FINEX factories. The hydrogen production cost when the plant starts production in 2021, after three years of modularised NOAK construction, was estimated in October 2014 to be KRW 2 442/kg at constant prices. The sale price of hydrogen was estimated to be KRW 6 500/kg.

The IRR and the benefit-cost ratio (BCR) after taxation were estimated to be 28.09% and 2.07 (2.66 without taxation), respectively. This led to the conclusion that nuclear hydrogen production is a profitable business with a payback period of four years.

POSCO consumes 3 504 MNm^3/year of oxygen by producing at a cost of KRW 40/m^3. Therefore, the utilisation of oxygen produced at a rate of 1 344 MNm^3/year by the 4 x 600 MWth hydrogen plant provides additional benefits of 53.76 billion KRW/year.

C. CO_2 emission reductions

According to the mass balance of the chemical reaction equation associated with the reduction of iron oxide Fe_2O_3, one tonne of steel production by full hydrogen reduction requires 54.15 kg of hydrogen as a reductant and reduces CO_2 emissions by 1 182 kg if it replaces the current carbon monoxide reduction. This is equivalent to 64% of the total CO_2 emissions by blast furnace steel production, which produces 1 840 kg of CO_2 per ton of steel. POSCO estimated that full hydrogen reduction steel production would reduce CO_2 emissions by 1 060 kg per ton of steel, a 57% reduction and slightly less than the reduction estimated by the chemical equation.

If the hydrogen reduction is applied to POSCO's three FINEX facilities with total capacity of 4.1 Mt/year, the total CO_2 emissions reduction will be 4.35 Mt/year. Overall, 42.4 Mt/year of CO_2 emissions may be avoided from the total steel production of 40 Mt/year in Korea.

POSCO estimated that 72.83 kg of hydrogen is required for stable production of one ton of steel (this is higher than 54.15 kg expected by the equation). Considering the 4 x 600 MWth NuH2-HPS hydrogen plant can provide 240 000 t/year of hydrogen to produce 3.3 Mt of steel, this plant reduces CO_2 emissions by 3.5 Mt. Note that this value can be smaller depending on energy sources to generate electricity required for the electro-electrodialysis based sulphur-iodine process.

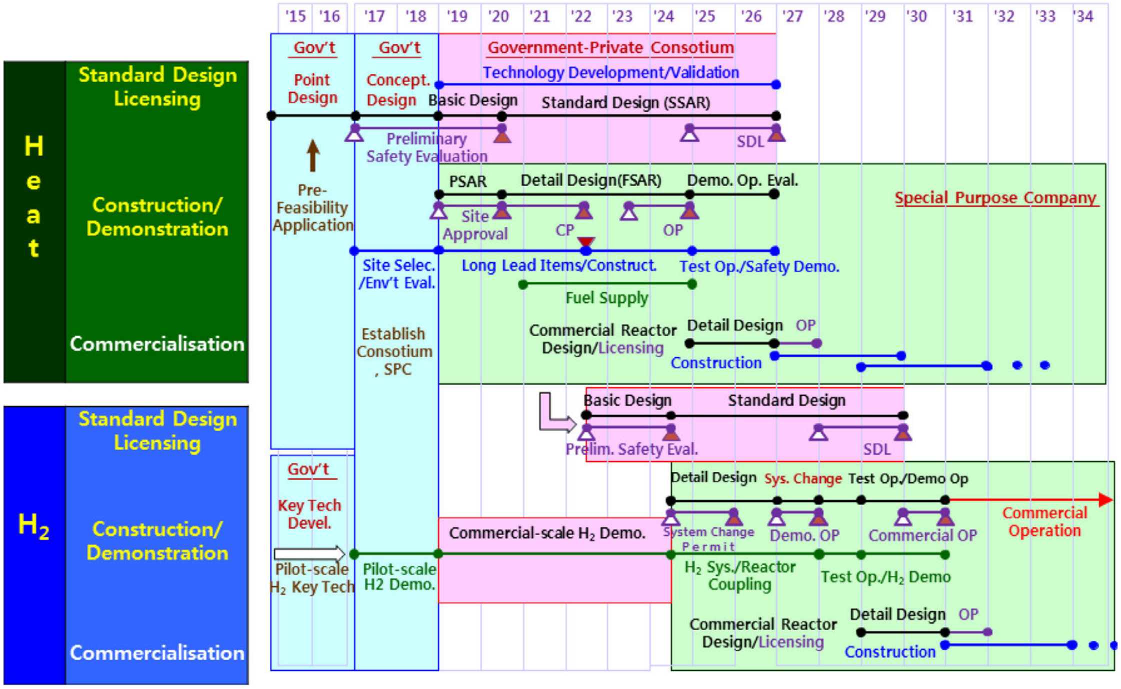
6.8.3. *Demonstration plan of process heat and hydrogen systems*

Demonstration plan

A long-term, two-step plan to demonstrate and commercialise the NuH2 systems was developed, as shown in Figure 6.42. To reduce technical and investment risks, the process heat production in operating conditions of 725°C and the hydrogen production in operating conditions of 950°C will be demonstrated in the same demonstration reactor by 2026 and 2030, respectively, depending on the order of technological maturity. The demonstration reactor size was determined to be 350 MWth to minimise scale distortion, to cover the operation and maintenance costs with some revenue for sustainable operation after the demonstration, and to secure the procurement of materials and components on the open market.

From the beginning of the integrated demonstration plant project, which requires KRW 2.165 trillion, the government and various private stakeholders should be involved to share the potential investment risks. Depending on the degree of risk, the share of involvement of government and private investment should be different at each stage of the project. (1) The conceptual design of the demonstration plant, requiring KRW 20 billion, is meant to have the government as a leading business, with the private sector participating with a 40% share. (2) The standard design licence, requiring 343 billion KRW to secure the design intellectual properties, is expected to be carried out by a consortium with a 50% government share and a share of 50% from the private sector, including mostly companies on the provider-side such as design, construction and equipment suppliers. (3) The demonstration plant's construction and commercialisation project, which pursues profits and requires a large-scale investment of KRW 1.802 trillion, is expected to be led by a special purpose company invested by various types of stakeholders such as the designer, the constructors and suppliers, the operator, the end users, and investors, as well as by the government with a minor share of 5%. If this plan is followed, the private sector will be responsible for about 90% of the total budget and the government will cover the remaining 10%.

Figure 6.42: **Demonstration plan of NuH_2 process heat and hydrogen systems**

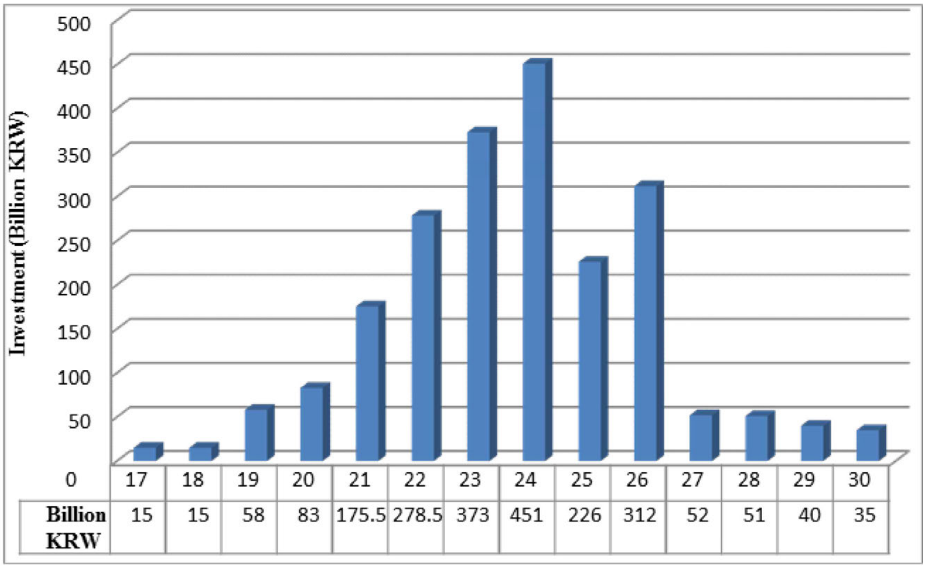


Source: KAERI (2015).

Table 6.40: **Demonstration project budget and budget division**

	Private (KRW billion)	Share (%)	Government (KRW billion)	Share (%)	Total (KRW billion)
Basic R&D	6.5	6	104.4	94	110.9
Key technologies	1.8	2	98.2	98	100
Concs/point design	4.7	43	6.2	57	10.9
Conceptual design	8.0	40	12	60	20
Standard design licence	159	46	184	54	343
Technology validation	26	20	104	80	130
Commercial H_2 demonstration	16	20	64	80	80
Basic design	24	60	16	40	40
Standard design	63	100	0	0	63
Standard design licence	30	100	0	0	30
Construction/demonstration	1 7145	95	87.5	5	1 802
Detail design	77	100	0	0	77
Equipment/install	1 510	100	0	0	1 510
Construction/OL	40	100	0	0	40
Test operation/demonstration	87.5	50	87.5	50	175
Total (design and construction)	1 881.5	87	283.5	13	2 165
Fuel facilities	85	100	0	0	85

Figure 6.43: **Demonstration project annual budget**



Source: KAERI (2015).

Site selection

- Evaluation index

About 20 indices to evaluate sites were developed by considering HTGR cogeneration-specific site requirements as well as general requirements for nuclear power plants. The general requirements are mostly related to compliance with the laws and regulations on surrounding population density, nearby disaster-causing industrial, traffic, and military facilities, meteorological and hydrological conditions, and geological, seismic, and subterranean characteristics. The following indices related to HTGR cogeneration are mainly associated with the issues that arise in relation to neighbouring nuclear or general industrial facilities.

1. Does the HTGR have synergistic advantages from being physically and technically close to nearby nuclear infrastructure?
2. Can the additional regulatory requirements introduced by the proximity of nuclear and industrial facilities be accommodated without great efforts?
3. Can the heat or hydrogen generated by the (V)HTR plant be easily transported to the end users?
4. Is the cooling water supply sufficient if the plant is located inland?

Land requirements

The integrated demonstration complex requires a total area of 322 000 m^2 including 123 000 m^2 for the hydrogen production plant, 33 000 m^2 for the tristructural-isotropic fuel fabrication facility, and 166 000 m^2 for the research and development centre. Considering that the subsequent commercial plant would require an additional 350 000 m^2 on the same site, a total of 672 000 m^2 of land area is required.

- Site selection

The optimal site for the NuH2 demonstration plant to supply hydrogen is adjacent to POSCO's FINEX hydrogen reduction steel factory in Pohang, which is in planning. Considering the high cost of pipelines, the site needs to be selected within 30 km of the end user.

Licensing strategies

- Licensing plan

The integrated demonstration plant is licensed through a two-step procedure consisting of the construction permit and the operation permit, according to the Law on the Nuclear Safety. In parallel with this two-step licensing, the standard design licence is pursued for both the process heat system and the hydrogen system in accordance with legal procedures for commercialisation.

The system change permit will be acquired because the change from the process heat system to the hydrogen system is planned in the integrated demonstration plant according to the long-term plan. In addition to the demonstration operation permit, the commercial operation permit is needed for the plant to produce hydrogen on a commercial scale. Since Korea does not have experience in licensing such a reactor for the multipurpose demonstration and the subsequent commercial operation, it is required to supplement the related laws, regulations and procedures.

The regulatory issues unexpectedly raised during construction are significant risks that may cause delays in construction and result in runaway increases in construction costs. Early communication with the regulator on licensing requirements, processes and expected issues is important.

- Licensing issues related to cogeneration

The licensing issues that may arise relating to the process heat production and hydrogen production using (V)HTR have undergone a preliminary review.

A. High-temperature design codes

The NuH2-PHS system with the outlet temperature of 725°C can be designed easily in compliance with the American Society of Mechanical Engineers (ASME) design code supplemented by ASME Section III, Division 5, “High Temperature Reactor”. The NuH2-HPS system, with an outlet temperature of 950°C and technology could, in principle, also be designed successfully if the ASME code cases for the candidate high-temperature materials and components are completed as planned.

B. Emergency planning zone (EPZ) reduction and simplification

In light of the intrinsic passive safety of the HTGR, the possibility of reducing the EPZ has been evaluated through a literature review of the related regulations and practices in Korea and many other countries, mostly applied to PWRs. Cases where a reduction in the EPZ was applied or sought were studied for HTGRs as well as other types of reactors in various countries. The findings were as follows:

1. Annex E of the US 10CFR50 states that “The size of the EPZs also may be determined on a case-by-case basis for gas-cooled nuclear reactors and for reactors with an authorised power level less than 250 MW thermal”.
2. The EPZ for Fort St. Vrain was 8 km, which is shorter than that specified in the US 10CFR 50.47 (about 16 km). This can serve as a reference in setting a reduced EPZ for VHTRs.
3. The US Nuclear Regulatory Commission (NRC) performed an evaluation to develop technical criteria and methods for the emergency planning for advanced reactors (SECY-97-020, 1997). It concluded that existing NUREG-0396 rationale, criteria and methods would be appropriate. However, it also recognised that changes to emergency planning requirements might be warranted if the technical criteria were modified to account for the lower probability of severe accidents or the longer period between accident initiation and radiation release. Several issues to be addressed for justification of these changes to the emergency planning basis were presented: (1) the probability level, if any, below which accidents will not be considered for emergency planning, (2) the use of increased safety in one level of the defence-in-depth framework to justify reducing requirements in another level, and (3) the acceptance of such changes by Federal, State and local emergency response agencies.

4. The NRC tried to develop a dose-based and consequence-oriented emergency planning framework for SMR sites as well as the EPZ size (SECY-11-0152, 2011) and presented an example of a scalable EPZ classified into four categories based on the distance at which the offsite dose becomes less than 1 rem.
5. It is necessary to constantly communicate and work with the Korea Institute of Nuclear Safety (KINS) to justify a reduced EPZ for VHTRs based on the quantitative backup data indicating enhanced passive safety features. Such backup data can include the offsite dose as a function of the distance from the reactor, as estimated by reliable numerical simulations.

C. Multi-module reactor licensing

The key issues related the licence for a multi-module reactor plant are: (1) whether it can be licensed with a single regulatory body's review, hearing, and safety evaluation report and (2) whether the single licence will guarantee the full licence validity duration for each module added over time. For these issues, the discussions that the NRC and the SMR and NGNP developers held on the most appropriate licence structure for multi-module facilities can serve as a reference.

The NRC suggested that the best licensing approach under current laws and regulations would be to continue the practice of issuing a licence for each reactor module (SECY-11-0079). It was recommended to define in a licence Annex the licence conditions for the structures, systems, and components (SSCs) common to all the modules to ensure they remain functional and meet the necessary requirements for each module for the full licence duration. The NRC concluded that it would be consistent with NRC regulations and existing practice to undergo a single licence review, safety evaluation report, and a hearing for a single combined construction and operating licence (COL) application made for modules of essentially the same design.

D. Nuclear facility - industrial facility boundary

In the relevant laws and regulations, the SSCs underlying physical safety protection, performing safety-related functions, or controlled by the reactor control room are specified as part of the nuclear facility for which the nuclear safety regulations should be applied. The issue is how to provide the design means to limit the influence that failures or transients occurring in the industrial facility can have on the safety functions of the nuclear facility, and vice versa, during normal operations, anticipated operational occurrences and accident conditions. The isolation header, the intermediate loop and the safety distance considered in the conceptual design of the NuH2 systems may provide such means. In addition, the detailed analysis of tritium migration to the industrial facility should be performed in further designs and the design concepts to limit the migration should be developed if necessary.

Technology development and validation

A plan to develop and validate the technologies required for the design, construction, and licensing of the demonstration plant has been made based on the list which defines the performance tests of SSCs according to the design data needs and the list which defines the safety tests according to the phenomena identification and ranking table.

Table 6.41 lists the 28 technology validation tests whose outline, background, requirements, device design and measured parameters, and schedule and budget are presented in "Technology Validation Plan for Nuclear Process Heat/Hydrogen Production Systems" (KAERI, 2014).

Table 6.41: **Technology validation items for nuclear process heat/hydrogen production systems**

1. Fuel	Water ingress test
Depletion performance test	Fission products migration test (platout/lift off)
Safety validation test	Tritium migration test
2. Core	**5. Mechanics and components**
Zero power critical test	Graphite blocks seismic test
Unrestricted core heat up test	Control rod drive mechanism test
Fast reactivity transient test	Hot gas duct performance test
3. Thermo-hydraulics	Steam generator performance test
Individual flow test for core components	Intermediate heat exchanger performance test
Lower plenum thermo-fluidic mixing test	Circulator performance test
Core fluid induced vibration test	Fuel handling system performance test
Fuel column ex-core integrated validation test	Shutdown cooling system performance test
4. Safety	Helium purification system performance test
Reactor cavity cooling system performance test	Isolation value performance test
High-pressure conduction cooling test	**6. Instrumentation and control**
Low-pressure conduction cooling test	Detectors performance test
Air ingress test	Components integrity and surveillance test

Source: KAERI (2018).

6.8.4. *Conclusion*

Plans have been developed in Korea for commercial-scale VHTR nuclear process heat and nuclear hydrogen systems. In addition to the design and functional requirements and the layouts and operating parameters, the design concepts of key components and their materials were investigated to ensure they can be manufactured and procured. The design concepts of buildings and facilities and the options for radioactive waste management and decommissioning were also evaluated.

A project plan was established to sequentially demonstrate the massive process heat and hydrogen production using a single VHTR plant. This includes the project structure and financing, the site selection and licensing strategy, and the technology development and validation plan. The economic feasibility study showed the competitiveness of the nuclear process heat and hydrogen production plant against the existing fossil fuel plant.

The study is at a sufficiently deep level of concept development to launch the demonstration project.

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6.9. Feasibility study on nuclear cogeneration development in the region of Paks (Hungary)

6.9.1. *Abstract*

Almost half of GHG emissions from the energy sector around the world are related to heat demand. The development of nuclear cogeneration offers a convenient possibility to reduce emissions; however, an examination of the economic constraints is essential. This study is focused on the heat demand of households in the vicinity of the Paks Nuclear Power Plant and compares economic and environmental aspects of domestic heating alternatives. In the first part, the study analyses the competitiveness of nuclear cogeneration in the district heating sector, while in the second part it considers the optimal heat systems for different building typological groups taking into account economic and environmental aspects, distance from the Paks Nuclear Power Plant, and heat demand density. The study finds that the potential for the development of nuclear cogeneration is considerable above a price for carbon emissions of EUR 5/t for the existing district heating network. In the region with high heat demand density nuclear cogeneration-based district heating can be competitive with stand-alone heaters primarily when environmental external costs are considered.

6.9.2. *Introduction*

The EU has adopted challenging carbon emission reduction targets that will require a substantive change in the energy sector. District heating, where the heat is produced with nuclear energy and hot water is piped to the buildings, has the potential to contribute to the achievement of these targets. Numerous examples of nuclear cogeneration are available in international reports and it should be noted that the direct heat consumption ratio is around 1% globally. Nuclear energy-based district heating is an established method for low-carbon household heating in Hungary. However, the heat consumption ratio in the Paks Nuclear Power Plant is far below the international level (Table 6.42). The Paks Nuclear Power Plant is a pressurised water reactor with freshwater cooling (VVER-440 Model V213) which supplies the heat demand of 2 600 households within a 4.5 km distance.

Although nuclear cogeneration has an insignificant share in the Hungarian district heating sector, the heat price is extremely low in the town of Paks (Table 6.43).

Table 6.42. **Heat consumption ratio in the Paks Nuclear Power Plant**

Waste heat	Electricity	District heating
65.70%	34%	0.30%

Table 6.43. **Price of district heating (for a 50 m^2 flat) in Hungary**

Paks	Szarvas	Average
Nuclear	Geothermal	Natural gas
EUR 150.80/a	EUR 288.38/a	EUR 596.55/a

In town of Paks the price is far lower than the Hungarian average. However, the demand side is limited.

The first topic of this study is to find the conditions when nuclear energy-based district heating with transmission pipelines could substitute natural gas-based district heating on economic grounds. In this part, the fuel, nuclear heat and capital costs played the key role and the effect of different GHG emission prices were examined in sensitivity analysis. The second part of this study compares the cost of nuclear heat provided through district heating with the costs of conventional heating systems. This comparison was carried out with standardised heat demand and examined the optimal heat supply in future projects.

6.9.3. *Methodology*

In the economic assessment of nuclear cogeneration, the fuel, operation and maintenance (O&M) costs of existing natural gas-based district heating, the "status quo", were compared to nuclear heat costs and the investment costs of installing a transmission pipeline with corresponding O&M costs. In a simple cost-benefit analysis, the focus was on the payback time for investments, and based on reduced heat generation costs the operation time of existing heaters was extended to the examined time interval. Therefore, the cost of retrofit was beyond the scope of this study. It should, however, be noted that lifetime of transmission pipelines is long (50-60 years) compared to natural gas boilers (25-35 years) or the unexpired operation time of the Paks Nuclear Power Plant (20-25 years). The time interval of this study was set around 20-40 years to reduce the uncertainty in calculations and uninterruptible nuclear energy generation was assumed (a Paks II Nuclear Power Plant). In net present value (NPV) calculations, the investment costs realised in the starting year were summarised (C_n; n=0) and "discounted" in present value of costs. Consequently, the present value of costs consists of a pair of insulated pipelines with near-surface installation in rural land, pump stations and a heat exchanger unit in the power plant. Sizing has a strong influence on costs. In general, sizing of the transmission pipeline to 50% of the thermal peak demand is acceptable to guarantee 85% of consumption. The annual difference between fuel and O&M costs of natural gas combustion and nuclear energy-based transported heat (benefit B_n; n=1..40) was discounted and summarised in the present value of benefits. The discount rate was r=4% and the examined time interval 40 years. The nuclear heat cost was concluded from the baseload electricity price and the efficiency of the nuclear power plant considering the operation and maintenance cost of the transmission pipeline. In the case of existing natural gas-based district heating, the fuel, maintenance and operation costs of power plant were considered.

Present value of the stream of benefits and costs:

$$PV(B) = \sum_{n=0}^{N} \frac{B_n}{(1+r)^n}$$

$$PV(C) = \sum_{n=0}^{N} \frac{C_n}{(1+r)^n}$$

Calculation of the overall economic impact over the whole lifetime of the project with discounting was done by net present value:

$$NPV = PV(B) - PV(C)$$

Unfortunately, the long time period makes the calculations with constant fuel and O&M costs somewhat uncertain. The forecasted costs (fuel and carbon price, neglected retrofit of gas boilers, etc.) increase the profitability of the investment markedly, which means that these calculations can be considered a sort of "worst case"-estimate. A further question was whether the enlargement of existing district heating network coupled with large-scale multi-flat buildings is appropriate. For comparison, three building types were established: large scale, medium scale multi-flat buildings, and single family houses with recent heating alternatives. In all three cases the heat load density is different and its influence on the capital costs of the district heating network is significant. The comparison is based on the unified heat demand of households (10.6 kW) disregarding the fact that the average area and energy needs are different for the three building types. The annual costs of domestic heating in a standardised case were compared and the technical operation times of alternatives were considered (with a discount rate of 4%). However, the carbon emission price and the external cost of environmental impacts were not considered.

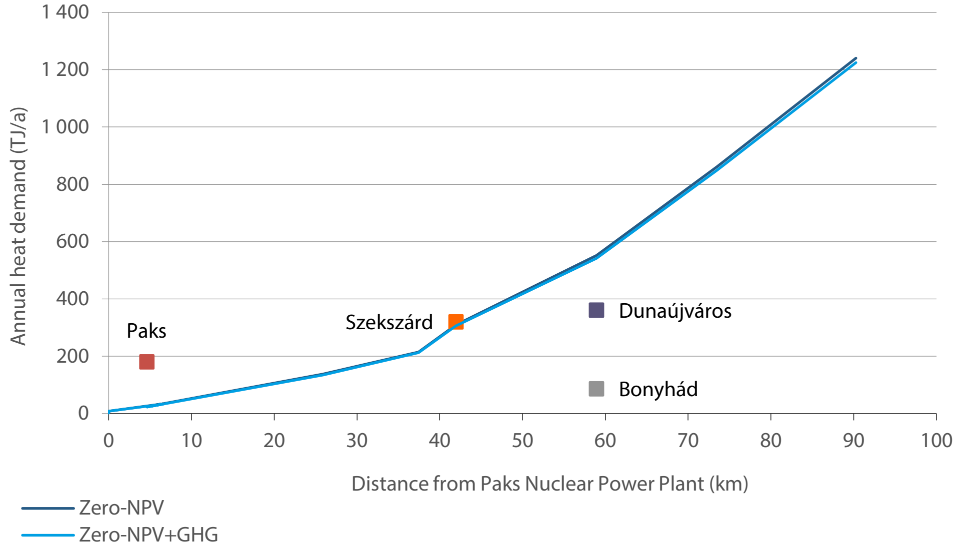
6.9.4. *Results*

The detailed analysis suggests that the substitution of natural gas-based district heating with nuclear cogeneration can be beneficial considering the lower fuel, O&M and carbon emission costs. The effects of two variables (heat demand *e* and distance of transport *r*) are crucial in the cost-benefit calculation. For all heat demand volumes and transport distances (e>0; r>0) it is feasible to determine a NPV(e,r) value of investment. The value of NPV(e,r) decreases as a function of distance

$NPV'_r(e,r) < 0$ and increases as a function of heat demand volume $NPV'_e(e,r) > 0$. The limit-curve defined with the NPV(*e*,*r*)=0 function determines the minimum heat demand values where investment can be beneficial. It is important to compare annual heat demands of existing district heating networks in the region of Paks with the position of the limit-curve (Figure 6.44).

Figure 6.44: **Towns in the region of Paks where nuclear energy-based district heating can be competitive**

(40-year payback period; 4% discount ratio; EUR 5/t carbon price)

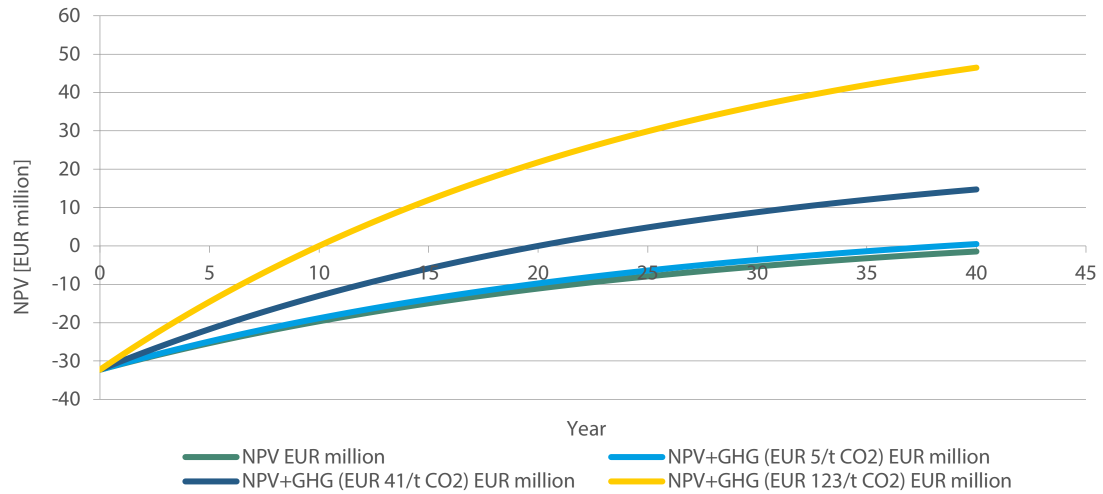


Source: HAS Centre for Energy Research (2018).

As can be seen, two towns have enough heat demand to consume nuclear heat economically: Paks and Szekszárd (they are above the limit-curve on Figure 6.44). On the basis of a partial sensitivity analysis, the transit pipeline development to the town of Dunaújváros could be beneficial only at a carbon emissions price of around EUR 25/t. However, that is considerably higher than the actual price (carbon emissions price in 2015: EUR 4.5-4.9/t). In the present situation, the installation of a nuclear heat transit pipeline only to Szekszárd is feasible on economic grounds (since it already exists towards Paks). A further question was how carbon emissions price increases could provide the basic level of revenue for a shorter payback period of the project. In the case of Szekszárd, the NPV of investment reaches zero only in 38 years considering the present carbon emissions price (Figure 6.45). To shorten the payback period to 20 years, a carbon emissions price of EUR 41/t is required. However, it should be noted that low-carbon scenarios in the energy sector predict even higher values. A shorter payback time may not be achieved realistically, as 10 years would require a carbon emissions price of EUR 123/t.

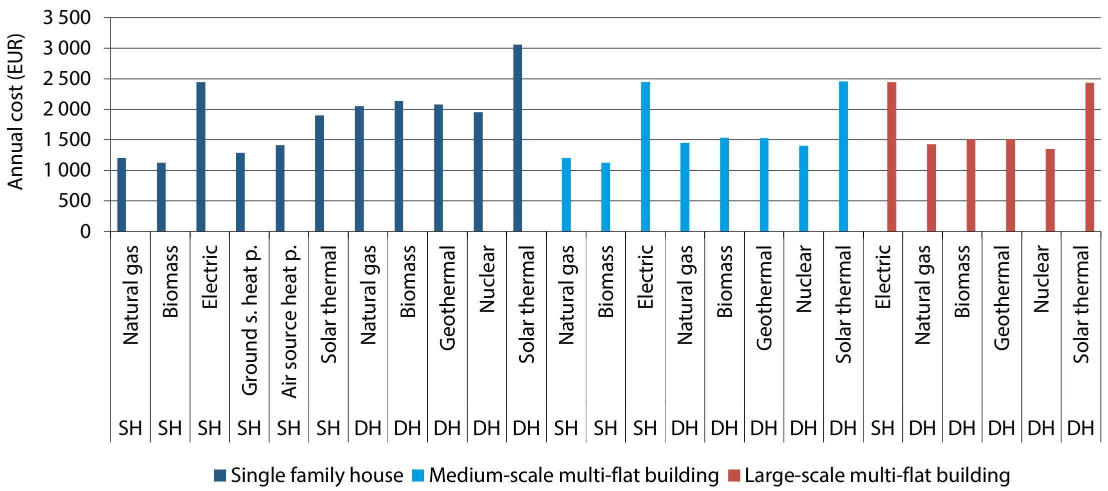
As it was mentioned previously, an important additional point was that the extension of the district heating network could be an economically attractive way to satisfy the expected heat demand growth. This question was addressed from the point of view of the domestic sector. Consequently, a comparison of heating alternatives was made with standardised heat demand for the three building types and a carbon emissions price was not considered. In the comparison, nuclear heat was the most competitive alternative in medium scale multi-flat buildings and in large scale multi-flat buildings, assuming that district heating network achieves a high penetration (Figure 6.46). However, stand-alone heating could be favourable in single family houses as result of the higher capital cost of the district heating installation.

Figure 6.45: **Time evolution of NPV for nuclear energy-based district heating at Szekszárd with different carbon prices**



Source: HAS Centre for Energy Research (2018).

Figure 6.46: **Annual cost of domestic heating in standardised case (140 m², 10.6 kW)**



SH: Stand-alone heater; DH: District heating.

Source: HAS Centre for Energy Research (2018).

6.9.5. *Conclusion*

The aim of this study was to identify the potential costs and benefits of a nuclear energy-based district heating development. The main benefit of moving to district heating is expected to be the carbon emissions savings it can deliver. Since a conservative approach was applied in the calculation, the results can be considered as most conservative. In the present situation, Szekszárd is the location with the highest potential for nuclear heat consumption. However, the long payback period caused by high capital costs and low-carbon emission prices increases the risk of investment. Overall, it is concluded that government guarantees (nuclear heat assurance in the long term) and enlargement of the customer group (medium scale multi-flat building) could promote the investment. For single family houses, the low heat load density is not advantageous for district heating but heat pump installations can contribute to reaching the carbon emissions reduction target.

6.10. Nuclear-renewable hybrid energy systems (United States)

The increasing penetration of variable renewables in the electricity markets is changing the scenario under which the energy supply mix has been designed. Variable renewables have an exceptionally low marginal cost and, therefore, in a competitive market they are eroding the share of the electricity demand usually supplied by baseload technologies such as nuclear. In regulated markets, variable renewable generators still have preferential agreements given the political desire to increase the amount of energy supplied by renewable sources. The increase in installed renewable capacity alters the energy markets and contributes to reductions in the share of electricity that could be supplied by conventional baseload technologies (e.g. nuclear).

Due to such change in the electricity markets, there is a growing concern over the capability of the market to supply financially viable capacity replacement if the current baseload fleet is forced to retire. It is possible that given the altered market conditions, less baseload will be built and more readily dispatchable supply will be required to meet demand (e.g. gas turbines), with a possible overall increase in electricity costs.

A way to avoid such a scenario is to consider how to take advantage of the large electricity price fluctuations (in the free market case) or periodic electricity overproduction (in a regulated market). The challenge that such an approach faces is the high degree of intermittence of electricity overproduction (or, exceptionally, low electricity prices).

The goal of the nuclear-renewable hybrid energy systems (NRHES), which are being developed under a US Department of Energy (DOE) programme, is to identify technologically feasible solutions capable of mitigating the impact of variable renewables in decreasing the baseload fraction while maintaining low electricity costs and a high standard of reliability. The overall Technology Development Program Plan is described by Bragg-Sitton et al. (2016).

An assessment of the problem

The work referenced in this report to assess the impact of variable renewable generators can be found in (Epiney et al., 2017).

A software and mathematical framework has been developed using the RAVEN code (Rabiti, 2014). A set of algorithms was developed to provide researchers the tools necessary to evaluate a large number of scenarios using demand, renewable generation and electricity pricing data from a few years. The scenarios produced retain the same statistical characteristics as the original scenarios such that they can be used to create large sample sets and to obtain a clearer picture of the possible evolution of the system (Chen, 2017).

In particular, two databases were considered in the research to date: one for wind speed and one for electricity demand. These two data sets were used to statistically characterise net demand (electricity demand less electricity supplied by variable renewable generators).

Algorithm description

The algorithm used to generate synthetic time histories (Chen, 2017) is briefly summarised here. Three different time periods need to be defined: (1) the shortest time period, which corresponds to the highest time dependence resolution (e.g. one hour); (2) the longest period, which spans the full time analysis duration (e.g. one year); and (3) the middle time period, which is used to create prototypical sub intervals. In the current study case, the selected time periods are hour, year and month.

Once the periods have been defined the process is as follows:

1. For each hour *i* in month *j*, the average across all the years contained in a regional database (electricity demand and wind speed are dependent on the geographical location) is computed.
2. For each month *j*, the one having the hourly values closest to the average values is chosen as being the prototypical month.
3. The prototypical months are assembled to construct the prototypical year.

4. The values for the prototypical year are decomposed using the discrete Fourier transform. An arbitrary number of frequencies can be used, e.g. frequencies from one year down to a few hours. The lowest frequency should correspond to the longest period (one year); the highest frequency should be such that there is no over fitting of the model (matching all the frequency data would be equivalent to always reproducing the same history). In the case considered here, the highest frequency corresponds to a three-hour period. This should ensure that the daily variation is captured without over fitting.
5. The signal produced by the Fourier transform is subtracted from the original time history.
6. The residual signal is normalised by forcing a normal Cumulative Function Distribution.
7. The normalised signal is used to train an auto regressive moving average (ARMA) model.

Two Fourier plus ARMA models have been trained: one for electricity demand and one for wind speed. To construct the net demand, a transfer function from wind speed to electricity generated by wind is needed. The corresponding function reported in Eq. 1 can be found in (Chen, 2017),

$$E[MWe] = \begin{cases} 0 & U \leq 3\left[\frac{m}{s}\right] \ or\ , U \geq 25\left[\frac{m}{s}\right] \\ 0.5\eta\rho U^3 \frac{\pi d^2}{4} & 3\left[\frac{m}{s}\right] < U \leq 14\left[\frac{m}{s}\right] \\ 3.6 & 14\left[\frac{m}{s}\right] < U \leq 25\left[\frac{m}{s}\right] \end{cases} \quad (1)$$

where:

- η: conversion efficiency of the wind turbine
- ρ: density of the air at the site
- U: wind speed
- d: diameter of the turbine blades.

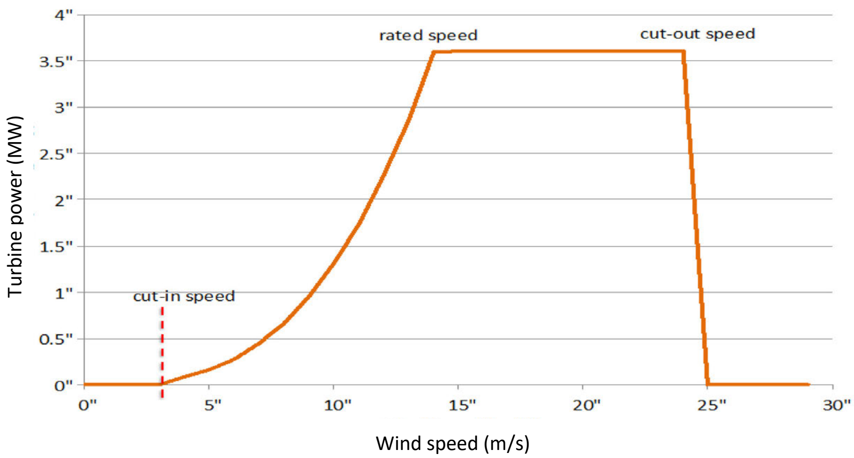
In this study the values assumed for each parameter are:

- η = 35%
- ρ =1.17682 g/m^3
- d = 90.00 m

while the wind speed is provided by the synthetic time history.

Figure 6.47 shows the power conversion profile. The value of 3.6 MWe is chosen as the nominal value (nameplate capacity) for computing the installed wind capacity.

Figure 6.47: **Wind speed to electricity conversion**



Source: Chen and Rabiti (2017).

Database characterisation and surrogate construction

The data sources and the frequency of the data are reported in Table 6.44. Pre-processing was performed to bring the time resolution to one hour (data were averaged over the hour) if the period presented in the data was shorter.

Table 6.44: **Database information**

Data type	Time span	Resolution	Region	Source
Wind speed	2004-2006	10 min (collapsed to 1 hour)	Site 3247	NREL [www.nrel.gov]
Load	2011-2015	Hourly	West	ERCOT [www.ercot.com]

Source: Epiney et al. (2017).

Following the algorithm described in the previous section, the minimal period captured using the discrete Fourier transform was three hours, and the months were chosen as representative periods over the years.

The trained ARMA plus Fourier model was used to generate one million synthetic time histories of the electricity supplied by the wind for five different levels of wind penetration scenario and for the electricity demand.

The five different levels of wind penetration correspond to a nameplate capacity of the wind of 10%, 20%, 30%, 40%, and 50% of the mean (average over the whole year) electricity demand. We can refer to these percentages as nominal penetration; the effective penetration is instead given by the nominal penetration times the capacity factor (ratio of the average effectively produced electricity to the nominal capacity).

For the wind time histories, the value used to assess the quality of the synthetic model is the load capacity factor. The conversion between wind speed and generated electricity is the one reported previously. This conversion is used to assess the capacity factor using the original database and the synthetic time histories. The actual value for the database is 27.93%, while the one obtained using the synthetic data is 27.44%. The minimal difference is an indication of the good quality of the synthetic time histories.

Table 6.45 shows the comparison of the 0th and 1st order statistical moments of the synthetic and actual data for the electricity demand (for one ARMA realisation). As expected, the differences are minimal.

Table 6.45: **Comparison of synthetic demand and actual demand**

Value	Synthetic	Actual
Mean	1.101 GW	1.095 GW
Sigma	20.626%	21.331%

Source: Epiney et al. (2017).

Assessment of the impact of wind penetration on the statistical properties of demand

As mentioned previously, five different cases are considered, where the nominal capacity of the installed wind generation equals 10%, 20%, 30%, 40% and 50% of the mean electricity demand. Net demand is computed as the difference between the electricity generated by wind and electricity demand. Table 6.46 provides global statistical quantities as a function of the wind penetration. First, these quantities show how the yearly mean net demand decreases with increasing wind penetration. As one can see, the decrease in mean net demand (third row) is well in line with the expected decrease (fourth row) computed from "wind penetration" multiplied by "wind load capacity factor (27.44%)," as computed from the original database. The last line of the table shows the sigma (standard deviation) of the time-dependent net demand. It should be noticed that these values are derived using the pooled standard deviation, i.e. the hourly-based variance is averaged over the full year, then its square root is used to obtain the global standard deviation. Moreover, those variances are relative to the mean net demand, therefore accounting for the decrease in mean net demand.

Table 6.46 states that in lieu of a decrease in the mean net demand by ~13% with respect to the mean demand at 50% wind penetration, the sigma of the net demand increases to ~21% while the demand has an original sigma of ~14.5%. This result highlights how by accepting a wind contribution that reduces the mean of the demand (becoming net demand) by ~13% we increase the sigma by ~6.5%. The sigma can be considered an indicator of the amount of reserve needed to ensure coverage of grid demand. If generators are required to cover a three-sigma distance from the mean (which corresponds to the 99.997 percentile under normal distribution assumption) the scenario with a nominal wind penetration of 50% would require a comparable amount of reserve (in absolute value) as the original scenario without wind.

Table 6.46: **Net demand mean and standard deviation as a function of wind penetration**

Wind penetration	0%	10%	20%	30%	40%	50%
Mean (over a year) net demand	1.104 GW	1.076 GW	1.048 GW	1.021 GW	0.993 GW	0.965 GW
Decrease in mean net demand (expected)	0	-2.744%	-5.488%	-8.232%	-10.976%	-13.720%
Decrease in mean demand (computed)	0	-2.536%	-5.072%	-7.518%	-10.054%	-12.591
Relative standard deviation	14.339%	14.876%	15.815%	17.102%	18.847%	20.904%

Source: Epiney et al. (2017).

To appreciate the impact of wind penetration on fluctuations in net demand, one can refer to the graphs provided in Figures 6.48-6.52. Before analysing the plots individually, it is helpful to recall that each of the scenarios is reported with respect to its own average (so, the average net demand). Hence, the fluctuation that is observed in Figure 6.48 for the different scenarios, for example, should be referred to with respect to the different means (of net demand) used as a normalising factor (which can be derived from Table 6.46).

Figure 6.48 shows monthly fluctuation (for the month of February) in relative terms with respect to the mean (of net demand). The fluctuations grow with increasing wind penetration.

This behaviour is even more pronounced when considering Figure 6.49, where the first percentile (on an hourly resolution) is plotted as a function of time (normalised by the respective hourly mean net demand). When planning for the addition of baseload capacity it is fundamental to ensure that there is sufficient demand to avoid operating the plant intermittently. An example of a metric for such assessment is to require that at any given hour during the year there is less than 1% probability of having insufficient demand in order to avoid any intermittence (or negative electricity prices). The 1% probability is referred to as the first percentile. This, however, is an arbitrary criterion; different baseload suppliers may choose different metrics according to their capability and willingness to accept variable load or negative prices.

Figure 6.49 reports the first percentile for different wind penetration levels. As can be seen in the figure, the first percentile decreases as the wind penetration level increases. At a nominal penetration of 50% the first percentile drops to almost zero, implying that baseload may need to flex or to accept negative prices.

This type of situation could be overcome by curtailing wind or by assuming that it would be advantageous for the baseload generator to pay the wind generator to stay out of the market (negative electricity prices) since it can make up for the losses at a later time when the demand is re-established.

The first percentile metric investigated here highlights a challenging situation for baseload plants even with an effective wind penetration of less than 15%.

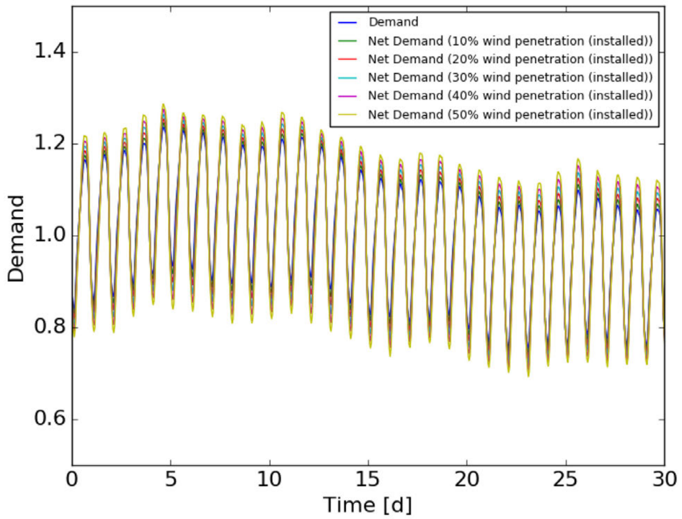
The impact of variable renewables is also significant in defining the total amount of reserve needed to ensure demand coverage. To perform this assessment, for example, we analyse the 99.999 hourly percentile, which is the minimum amount of capacity needed to ensure that at any given hour of the year there is less than 10^{-5} probability of blackout. Figure 6.51 shows how, when considering the 99.999 percentile, the reduction in mean value of the demand is almost completely offset by the increase in volatility, such that the overall load capacity needed (without the renewable) remains almost unaltered.

To clarify the concept, consider a 1 GWe mean demand from which we subtract wind supply at a 50% nominal penetration. This yields a mean value of the corresponding net demand equal to 1GW*(1-12.591%) = 0.87409 GW (number is taken from Table 6.46). For the 50% case, the highest value of the 99.999 percentile is 2.207 (Figure 6.51), so the total installed capacity needed (including reserves) is 2.207*0.87409=1.930 GW. For the case without wind the highest value for the 99.999 percentile is 1.930, so the total installed capacity needed (including reserves) is 1.930*1. In conclusion, the analysis of the 99.999 percentile reveals that an increase in installed wind capacity does not decrease the reserve requirements. The benefit of wind is limited to cheap electricity production but requires all the capital investment to ensure reserves are still available. The situation depicted here is dependent on the very stringent reliability limit imposed (99.999% hourly percentile). A more relaxed constraint might show a decrease in necessary reserves as the wind penetration increases.

Overall, the analysis could benefit from several improvements, including: a) consideration of the correlation between wind and electricity demand; b) wind data may need to be collected over larger regions to decrease the sigma (standard deviation); and c) one million points is still a low number to estimate the point wise 99.999 percentile since only 10 points are expected to construct such estimation leading to a 30% sigma on this estimation. Nevertheless, the effect is clear even considering such uncertainty.

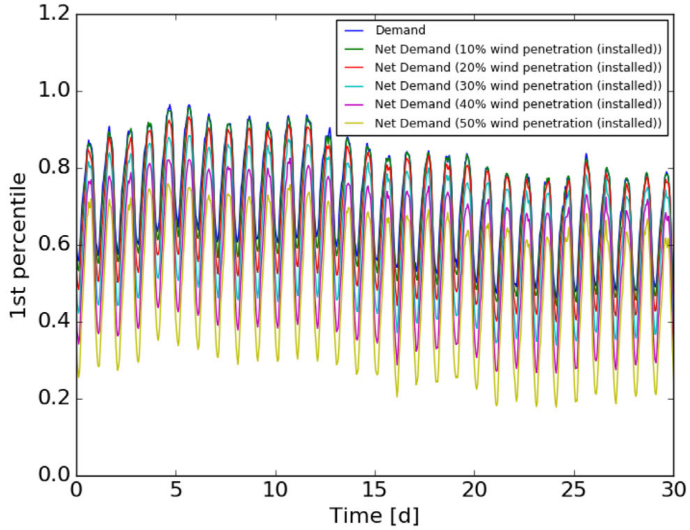
The value of the sigma of the net demand (see Table 6.46) as a function of the wind penetration can instead be considered fully reliable given the large number of samples. The sigma clearly shows an upward trend. For the 50% wind penetration scenario that shows a decrease of ~13.5% in the mean net demand, the sigma increases from 14.339% to 20.904%, meaning that the 1 sigma upper limit (mean+1 sigma) has decreased only by ~4.06%. The same result can be seen from the time-dependent sigmas for the different wind penetrations shown in Figure 6.52.

Figure 6.48: **Demand and net demand (with respect to their means) for the month of February for different wind penetrations**



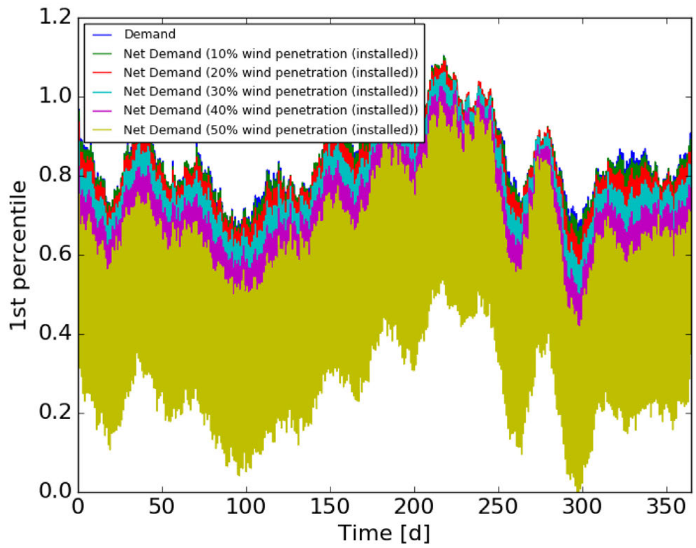
Source: Epiney et al. (2017).

Figure 6.49: **Demand and net demand first percentile (with respect to their means) for the month of February for different wind penetrations**



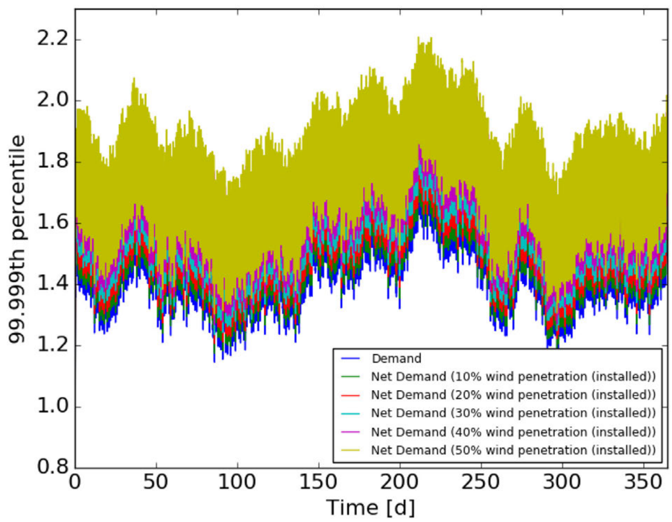
Source: Epiney et al. (2017).

Figure 6.50: **Demand and net demand first percentile (with respect to their means) for one year for different wind penetrations**



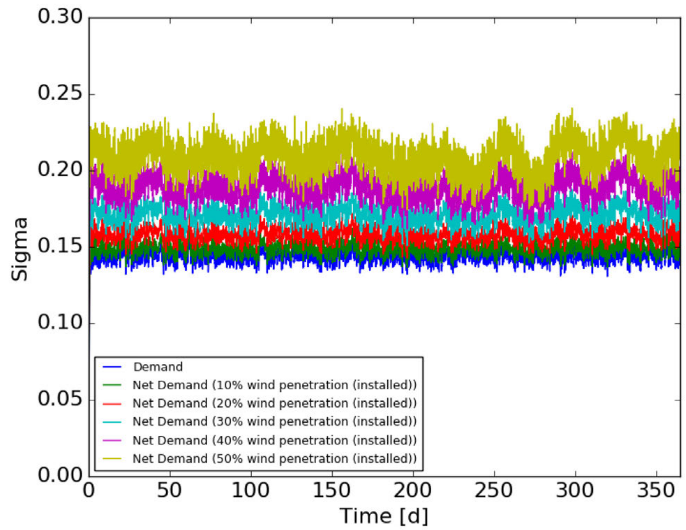
Source: Epiney et al. (2017).

Figure 6.51: **Demand and net demand 99.999% percentile (with respect their means) for one year for different wind penetrations**



Source: Epiney et al. (2017).

Figure 6.52: **Demand and net demand sigma (with respect their means) for one year for different wind penetrations**



Source: Epiney et al. (2017).

An assessment of the problem

Analysis of the effect of wind penetration on the statistical properties associated with net demand, even accounting for the above-mentioned limitations of the methodology, points to a decrease in the baseload availability and an overall increase in volatility of (net) demand. In general, the energy suppliers with fast dispatchable ramp rates are characterised by the highest levelised cost of electricity (LCOE); therefore, it seems reasonable to expect an increased cost to meet the kWh of net demand with high wind penetration relative to the original demand.

Overall, two effects compete in determining the average cost of electricity: the increase in the cost per kWh of net demand (due to an increase in volatility), and the reduction of the mean net demand due to contribution from variable renewables, which could have a very low LCOE. Hence, the more demand that is covered by low-cost wind the less net demand must be met, but the cost to meet such remaining net demand increases due to the increased volatility.

Hybrid energy systems as a possible solution

A possible solution to the problem described above is to decrease volatility in net demand by adding a positive demand that is low when the net demand is high and high when the net demand is low. We can think about this as a mechanism to counteract the contribution to volatility from variable renewables. It may even be possible to decrease the relative sigma of the net demand below the relative sigma of the original demand.

The US DOE Nuclear-Renewable Hybrid Energy System project aims to assess the viability of such a solution by introducing an additional demand, such as an industrial process. The product of the industrial process will be referred to as the "co-product".

Candidate industrial processes should exhibit a combination of the following characteristics:

- Possibility to store the co-product at low cost. This allows the process to absorb the overproduction of energy (in periods of low electricity price) and to compensate for underproduction (in periods of high electricity price). This characteristic can be thought of as the capability to create a proxy for energy storage.
- Cost structure dominated by variable costs. This criterion ensures that the system economics will not be too heavily penalised by periods of underutilisation of the facility. In fact, in this case costs would be more responsive to production levels and less related to the facility capital costs.
- Variable costs dominated by energy costs. This characteristic amplifies the benefit of buying low-cost energy, when available, compensating for the possible times of zero production when capital recovery expenses accumulate (see previous point).
- Use of heat process at a temperature close to what is available at the secondary side of the nuclear plant. This characteristic helps overcome the disadvantage of the nuclear system versus other means of electricity production with higher thermal conversion efficiency (light water-cooled nuclear technologies achieve an efficiency of only ~35% due to the relatively low output temperature, ~300°C).

The above-illustrated characteristics are just a guide to select possible candidate energy users, but a more detailed technical and financial analysis must be conducted after candidates have been selected. The financial analysis framework is discussed in the next section.

The financial point of view

From the financial point of view, it is not always clear which figures of merit need to be considered, as these are a function of the different perspectives brought by a set of possible observers. For a company considering investment in a hybrid system a desirable figure of merit would be the net present value (NPV) of the cash flow to the firm discounted at the weighted average cost of capital (WACC), or the IRR greater than WACC of any other possible investment with the same risk profile, depending on possible capital constraints and reinvestment opportunities.

For a shareholder, a rate of return to shares greater than the one computed using the capital asset price model (CAPM) would be a good figure of merit.

The approach described here only uses the system cost that will be incurred to cover demand (provided a given statistical profile). The system cost is computed as the price of electricity that would make the NPV of the cash flow to the firm equal to zero when discounted at the WACC. This approach is very similar to the one that would be taken by a grid manager operating in a fully regulated market to optimise the electricity-producing portfolio. This is equivalent to minimisation of the actual levelised cost of electricity (LCOE), which is based on the actual capacity factor (amount of product sold versus nameplate capacity).

It is relevant to note that in the case of an assessment based on NPV, IRR or CAPM, the analysis of the hybrid system investment is exposed to the electricity market price. In the case of the actual LCOE, the hybrid system is instead exposed to the demand profile. This is an important distinction since the first three options seek to determine, given a market, how the investor will make the most profit from his assets, whereas the fourth option assesses how a need (demand) can be fulfilled at the lowest cost to the community.

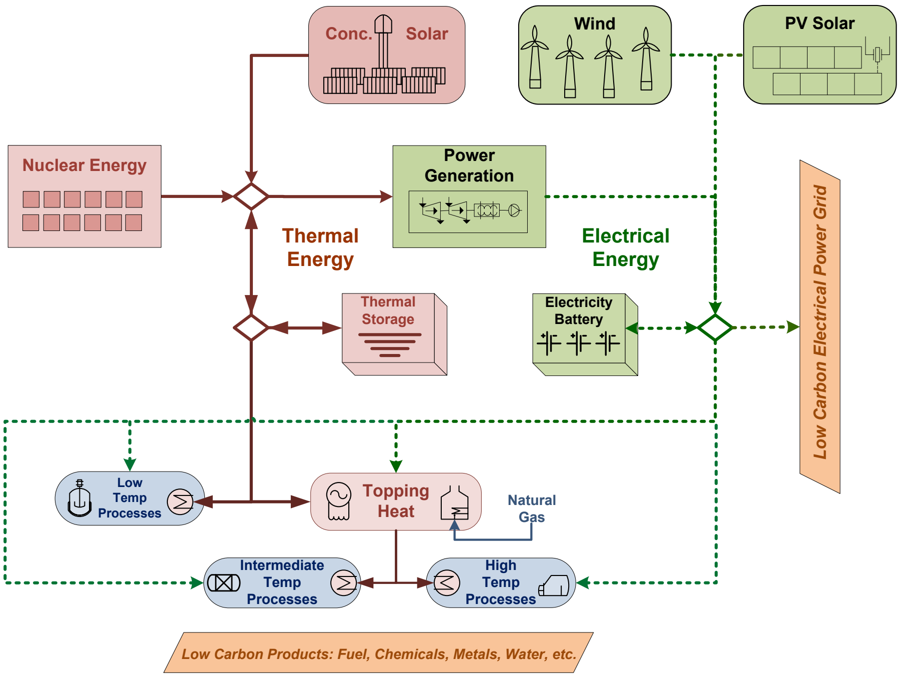
In a perfect market the transition from the short-run equilibrium to the long-run equilibrium in the supply/demand dynamic would ensure creation of the most effective supply portfolio, such that the cheapest option is available to the customers. However, this does not seem to be the case in the electricity market. In reality, the problem is more dependent on the definition of the time scale of the long-run equilibrium. Nuclear plants have an operating lifetime of ~40 to 60 years, and several life cycles are needed to establish the long-run equilibrium. Hence, observations of the energy market only reflect the first round of feedback between variable renewable generators and nuclear plants.

The physical system

Figure 6.53 provides a sketch of the physical assets that may be included in a hybrid system (conceptual configuration for a tightly coupled option; see [Bragg-Sitton et al., 2016] for additional options). Several possible configurations are being considered. The layout shown in Figure 6.53 has the strongest potential for efficient energy recovery as a result of the direct thermal coupling between the nuclear plant and the industrial user.

For electricity-only coupling, benefits may arise from the creation of an internal market structure agreed within the hybrid system where, internally, the system creates a fully regulated market and externally bids on electricity prices. Further investigation will be needed in this respect to determine if a close co-operation between the components of the hybrid system could lead to an overall improved economic performance of the hybrid system. Such a configuration and operating modality would also require review and approval by regulators of the electricity market.

Figure 6.53: **Conceptual tightly coupled hybrid energy system layout**



Source: Bragg-Sitton et al. (2016).

Ongoing analysis

Software models of several possible hybrid energy systems are being developed under the nuclear-renewable hybrid energy systems (NRHES) programme. The objective is to optimise component sizing within each hybrid system to minimise the LCOE for random demand profiles generated following the approach described at the beginning of this section.

This problem has several challenges. The primary challenge is the construction of an optimal dispatch profile for a given profile of the electricity net demand. Because it is not driven by marginal price, the dispatch should be based on a global optimisation in which the total degrees of freedom can easily exceed several thousand. Initial results from this work are expected towards the end of 2017, when the optimisation of a hybrid system, based on an hourly resolution of the dispatching problem, will be reported in a publicly available document.

Limitation of the current approach and conclusions

There are several limitations in the current approach. First, it is necessary to consider that the stochastic modelling of variable renewable generation and demand is challenging, and the current analysis does not account for cross correlation. When solar energy generation is introduced, the cross correlation between demand and variable renewable supply is of greater significance such that the analysis does not overestimate the introduction of volatility in the net demand.

The work presented thus far is based on an hourly resolution, but several of the hybrid system components have a much shorter time scale. This modelling assumption can give the illusion of dealing with a system without inertia. It will be necessary to increase the time resolution in future analyses in order to consider the eventuality that the system will not be capable of exactly matching demand. Models to quantify the value (cost) of missed demand are under development and will be needed in the global optimisation approach.

In spite of the acknowledged limitations, the system cost approach, the challenging global optimisation, and the construction of accurate software models of each component in the hybrid systems represents a comprehensive approach to assess the economic viability of coupling the (nuclear supplied) baseload with variable renewable generation by introducing one or more stabilising loads within the energy system (i.e. industrial process and batteries).

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Chapter 7. **Conclusions and recommendations**

7.1. **Main findings**

Nuclear power has been the single largest source of low-carbon electricity over the past 50 years in advanced economies. In order to meet the 2-degree objective of the Paris Agreement, the International Energy Agency expects installed nuclear capacity to double by 2050 compared to 2020 (IEA, 2021). A further contribution to the decarbonisation of the world's energy sector can be made by using heat (steam) and electricity from nuclear reactors for non-power applications: district heating, production of hydrogen and synthetic fuels, or desalination, which are all processes that today mainly run on fossil fuels (coal, oil, gas) or biomass. In addition to the concerns about global warming and CO_2 emissions, heat production is responsible for a large part of air pollution issues worldwide. Indeed, unlike electricity, heat is produced close to where it is consumed. This means that when fossil fuels are burnt for building or industrial heating or in transport, airborne pollutants are spread out over residential and industrial areas, causing sometimes severe public health problems for urban dwellers and workers. Since nuclear energy emits exceptionally low amounts of CO_2 and air pollutants, it can be considered one of the solutions to limit CO_2 emissions and air pollution from the heat sector. Another important strength of nuclear power is its stable production cost, and the potential to offer price stability to industrial consumers. Cogeneration can also dramatically reduce primary energy resource consumption by greatly increasing the efficiency in energy use, from a global average of 37% for conventional power generation to 80% for cogeneration of heat and power.

Applications of nuclear thermal energy to date have been limited to low-temperature applications such as desalination and district heating, which require thermal energy at temperatures up to a maximum of 200°C, which can be supplied by the current generation reactors. All nuclear cogeneration to date has used less than 1% of the total thermal energy output of the world's nuclear fleet. There have been few applications of nuclear thermal energy for industrial processes. The advanced nuclear reactors that are under development as generation IV reactors and several types of small modular reactors (SMRs) have higher outlet temperatures and are therefore better suited for supplying heat to industrial processes.

Cogeneration applications of nuclear energy are most likely to develop if nuclear cogeneration is more economical than the technical solutions it replaces, essentially gas-fired production of steam and electricity. Because of its large upfront capital costs (for large LWRs or advanced generation IV reactors) and economies of scale, nuclear energy might be appropriate, i.e. competitive against fossil fuel applications, for significant combined heat and electricity demand. SMRs may certainly address other market segments if they demonstrate their competitiveness. A good understanding of the economics of nuclear cogeneration, including the associated system costs, is essential. Even though there are proven examples of developing non-electrical applications of nuclear energy at an industrial scale, especially in the area of district heating, there is no clear methodology to assess the economic case for developing such applications further. The lack of a well-defined economic assessment methodology makes the development of a business case for non-electrical applications of nuclear energy difficult. One of the aims of the proposed study was to fulfil this methodology gap by developing an approach that can help assess the costs and benefits of developing other products besides electricity. Various cost allocation methods were explored in this study, including credit cost allocation methods (used in some of the economic models such as G4ECONS V2.0, HEEP and DEEP), prorating cost allocations based on exergy or calorific value, and the opportunity cost method. Some economic methods suit specific cogeneration applications better than others depending on their business models and the project characteristics. The choice of a cost allocation economic model mainly depends on the business model, market conditions and the intended use of cogeneration. For example, for desalination applications using a significant portion of the reactor thermal output, a power credit methodology for cost allocations between electricity and heat is more appropriate. On the other hand, if the desalination uses only the waste heat from the reactor, the exergetic method is more applicable. For district heating applications, the opportunity cost method is the most suitable when the nuclear power plant already exists and operates; it allows the district heating application to be considered as an extra source of revenue, not interfering with the existing business model. Economic models for the nuclear-renewable hybrid energy systems focus on maximising profits for the entire system, consisting of the nuclear power plant, renewable generating sources and industrial process, by allocating energy (thermal and electrical) between electricity to the grid and the industrial product, and taking into consideration market prices and demand.

This study also explored business models for nuclear cogeneration. Financing a nuclear cogeneration plant raises additional challenges and opportunities compared to electricity-only nuclear plants: more stakeholders are involved. Cogeneration plants play in a twofold market (electricity and heat). Yet, these two markets are not equally segmented. In most countries, power grids are developed to a broader extent than heat networks. Therefore, the cost of "reaching" a new electricity consumer is negligible compared with the cost of developing infrastructure to supply heat to new clients. The most important parameter defining cogeneration market segments is temperature. When considering nuclear power as a heat source, it is therefore important to consider the thermal capabilities and limits of the various reactor technologies. Other significant parameters are the amount of heat needed, specific safety requirements, plant adaptation to load transients, plant availability and reliability, heat transport technological limits and, importantly, the licensing of a coupled nuclear plant with cogeneration facility. The extent of integration between stakeholders, including the nuclear power plant, end user of heat, energy manager and distributor, and the grid, will depend on the market segment targeted for the cogeneration application. The financing and ownership model for an application will depend on the extent of integration. For district heating applications, both integrated and non-integrated business models have been used. Integrated models were used for district heating in the Soviet Union when both the nuclear plant and the heating network were built at the same time and owned by the same utility. The district heating system in Beznau, Switzerland, is a non-integrated system where the nuclear plant and heating network are owned by two separate companies. In most cases, the desalination plants are owned and operated by the same companies as the nuclear power plant and are integrated clusters. Therefore, the most common ownership models for nuclear desalination are either the build-own-operate model or a model where ownership lies with a standalone entity. In the future, growing demand for fresh water may lead to separate companies for the operation of the nuclear power plant and the desalination facilities. Since there is no experience in high-temperature nuclear cogeneration (> 250°C), there is no dominant business model. Therefore, devising innovative solutions (in funding, business modelling, on-site integration, etc.) will be necessary. The nuclear-renewable hybrid energy systems (NRHES) could include a nuclear reactor, power generation unit, windmills, solar photovoltaics (PV), thermal and electrical storage, and an industrial process. The NRHES capital costs far exceed those of any of its subsystems. Therefore, creative business models would be required for a NRHES to enable large investments and set up a business structure that would ensure internal energy dispatch decisions are made to maximise profits for the entire NRHES and not for individual subsystems.

Members of the expert group completed case studies on nuclear cogeneration applications including district heating, water desalination, hydrogen production and other industrial applications. Case studies on district heating included both existing systems (Switzerland, Hungary) as well as proposed projects (Finland, France, Hungary, Slovenia). In Switzerland, the Beznau Nuclear Power Plant has continuously provided 15 000 people with thermal power for more than three decades. The nuclear steam from the nuclear power plant is competitive compared with the fossil fuel-based solutions, even with depressed fuel prices. The economic assessment shows that steam extraction from a nuclear power plant could be a beneficial alternative in the context of decreasing market prices for electrical energy, especially if there is a flexibility to react in time to the changes of the energy market rate. Other case studies explored connecting the existing and/or new heating networks to existing nuclear plants. Although these studies show potential for nuclear district heating to replace conventional sources, certain challenges were noted. The remaining operating time frame of the existing nuclear power plant, including a planned extension, is a consideration for the long-term viability of a new district heating system connection. The economic competitiveness of nuclear district heating also depends on the distance between the plant and the heat consumers, the extent of retrofitting required for the heating network, and the cost of retrofitting an existing nuclear plant or building a new one. The high investments in plant and distribution network retrofitting and the long-term operations of this technology would require favourable financing and policy support to promote this low-carbon heat source on the sites where it is technically feasible.

Although most water desalination plants so far have been based on heat supplied from water-cooled reactors, the cases explored in this study are based on advanced reactor concepts. A multi-stage flash (MSF) desalination process specially configured and optimised to efficiently recover the sensible waste heat from the power conversion cycle of the Japanese high-temperature gas-cooled reactor GTHTR300C is shown to produce 45% more water than the traditional MSF. The cost of desalinated water produced from the GTHTR300C, for the Middle East market conditions, is estimated to be significantly lower compared with those of the conventional MSF cogenerating with an oil and gas-fired CCGT power plant. Another case study showed economical desalination of sea water using a hybrid of reverse osmosis and multi-effect distillation (MED) units coupled with SMART, a Korean-designed 330 MWth integral pressurised water reactor. SMRs could be more suited for desalination without emitting GHGs as the demand for desalinated water is growing rapidly.

Case studies for hydrogen production were based on high-temperature, water-splitting processes using high-temperature heat and electricity from advanced generation IV type reactors. Large-scale hydrogen production using sulphur-iodine thermochemical process coupled with a very high-temperature reactor (VHTR) with outlet temperatures up to 950°C was found to be economically feasible in Korea and Japan. The analysis also showed that the sulphur-iodine thermochemical process is economically competitive compared with water electrolysis, which is the only method currently available for GHG-free hydrogen production. A case study for large-scale hydrogen production using high-temperature steam electrolysis (HTSE) coupled with a supercritical water-cooled reactor (SCWR), with outlet temperature of 625°C, showed that the levelised cost is significantly higher than the hydrogen produced by conventional process using natural gas with low prices in North America. This analysis shows that nuclear hydrogen can be competitive in certain regions depending on natural gas prices and carbon taxes. The high-temperature water-splitting processes are still under development and have not been demonstrated on an industrial scale but are expected to be ready when the VHTR technology is ready for deployment. Development of the interface with industrial heat users, including intermediate heat exchangers, ducts, valves and associated heat transfer fluid, is one of the key objectives for the VHTR's development.

One of the interesting concepts is a hybrid energy system which has a large share of renewable technologies. Nuclear-renewable hybrid energy systems (NRHES) are proposed to allow integration of nuclear with renewable resources using cogeneration of electricity and an industrial product, such that the optimised integrated system meets the electrical power requirements of the grid while ensuring the economic viability of the entire system. Electricity production is preferred when electricity demand is high and prices are high. On the other hand, the energy is diverted to industrial processes when electricity prices are low. The NRHES capital costs far exceed those of its subsystems such as the nuclear plant, industrial process, and wind- or solar PV farms. Therefore, creative business models would be required for the NRHES to enable large investments and set up a business structure that would ensure internal energy dispatch decisions are made to maximise profits for the entire NRHES and not for individual subsystems.

The coupling of a nuclear power plant with an industrial facility and the related safety issues are important points to consider for licensing. There have been only few instances where a large-scale industrial cogeneration system located near the nuclear plant was licensed by the national regulator (for example, large-scale heavy water plants located near the Bruce nuclear power plants were licensed by the Canadian regulator). SMR designs with safety features allowing siting close to applications and with relatively small powers may be more adapted to the cogeneration applications. Safety analyses and licensing considerations as well as public acceptance, could determine the viability of a cogeneration application.

The group of experts discussed the main findings of the study, listed below.

Role in decarbonisation

- Nuclear cogeneration is part of the solution to achieve the global energy decarbonisation goals set under the IEA's Net Zero scenario.
- Cogeneration is an integral part of the future of nuclear energy, as it allows further reductions in CO_2 and air pollution coming from fossil fuel burning (including biomass), improves the efficiency of the plant, and limits thermal pollution.
- There is a need to better inform the general public and policymakers – as well as industry at large – about the potential of nuclear cogeneration.
- Economic and environmental benefits are decision drivers, but relevant stakeholders need to be involved at the early planning stage in order to build public acceptance.
- The potential market for nuclear cogeneration is significant – even targeting a fraction of the heat market could translate into a high number of new reactors – provided the business case is favourable.

Opportunities and challenges for nuclear cogeneration

- The experience of nuclear district heating (DH) in some countries has been a remarkable success (for example Switzerland, with more than 30 years of continuous operation) in terms of high availability of low-carbon and affordable heating to local consumers.
- Nuclear DH may be a mature technology, and nuclear power plant designs can be made to incorporate cogeneration readiness, but it should also be recognised that DH operators have alternative choices. Thus, proponents of nuclear DH should work with DH operators to build a more convincing case.
- The cost of the heat transport line is a major factor affecting the competitiveness of nuclear DH, especially in countries where nuclear power plants are typically located several tens of kilometres from large urban centres. If the cost of the transport line is not allocated to the nuclear cogeneration project, nuclear DH is the most competitive solution.
- For desalination projects, there is a need to address energy policies and water policies in a co-ordinated manner.
- SMRs could be more suited for desalination without emitting GHGs, as the demand for desalinated water is growing rapidly.
- The advanced nuclear reactors that are under development as generation IV reactors and several types of SMRs will have higher outlet temperatures and could therefore be more suited for supplying heat to industrial processes.
- The problem of the difference in time frames of nuclear power plants (40 to 60 years) and of industrial plants that could use process steam (20 years or less) needs to be addressed. For district heating, the time frames of nuclear and district heating systems are similar.
- The concept of nuclear-renewable hybrid energy systems shows that cogeneration can play an important role to better integrate variable renewables and nuclear plants in decarbonised energy systems.
- Coupling nuclear power plants with an industrial facility and related safety issues are important points to consider in licensing. There is not enough information regarding the licensability of cogeneration applications in existing and new nuclear power plants.

Economic and business considerations

- Cogeneration applications of nuclear energy are most likely to develop if nuclear cogeneration is more economical than the technical solutions it replaces, mainly gas-fired production of steam and electricity.
- Some economic methods suit specific cogeneration applications better than others depending on their business models and the project characteristics. The main considerations for the choice of a cost allocation economic model depends on the business model, market conditions and the intended use of cogeneration.
- Nuclear cogeneration is for many applications (district heating, desalination) already technically possible, but the economic case is not necessarily developed yet. Governments can incentivise investments related to nuclear cogeneration by appropriately valuing the cost of CO_2 emissions avoided.
- For some (advanced) reactor technologies, it seems that the economic case can be made more favourable since even the waste heat can be used for non-electrical applications, at no cost to the power output of the nuclear reactor.
- The (economic) case for nuclear cogeneration, whatever the application, is very dependent on country-specific and application conditions (for example the price of natural gas in the region).
- Case studies shows that nuclear hydrogen can be competitive in certain regions depending on natural gas prices and carbon taxes.
- Financing a nuclear cogeneration plant raises additional challenges and opportunities compared to electricity-only nuclear power plants as more stakeholders are involved.
- Since there is no experience in high-temperature nuclear cogeneration (> 250°C), there is no dominant business model. Therefore, devising innovative solutions (in funding, business modelling, on-site integration, etc.) will be necessary.
- The extent of integration between various stakeholders, including the nuclear plant, end user of heat, energy manager and distributor, and the grid, will depend on the market segment targeted for the cogeneration application.
- Creative business models would be required for nuclear-renewable hybrid energy systems to enable large investments and set up a business structure that would ensure internal energy dispatch decisions are made to maximise profits for the entire NRHES and not for individual subsystems.

7.2. Recommendations

Although total operating experience of nuclear thermal energy amounts to about 750 reactor-years, only a small fraction of that has been used for cogeneration applications. Nuclear energy has contributed significantly to avoiding the emissions by providing low-carbon electricity, but its potential to replace fossil fuels for industrial applications has not been fully realised. The ongoing development of generation IV reactors and SMRs opens further opportunities for cogeneration applications. To realise the potential of nuclear cogeneration for decarbonisation, the group of experts made a set of recommendations as listed below.

- Governments should consider developing national/regional roadmaps for decarbonising the heat sector: often only roadmaps for the electricity sector are developed. These roadmaps should take into account nuclear energy's potential to replace fossil fuel used for heating in industrial and commercial sectors.
- Governments should recognise that nuclear cogeneration can be an integral part of integrated low-carbon energy systems. Government policies should support nuclear thermal energy and discourage fossil fuel use through carbon taxes and other incentives.

- Governments should co-ordinate energy and water policies to advance nuclear desalination projects. The energy and water planning communities should work together on innovative financing and business models for water desalination projects.
- There is a need for demonstration projects to advance nuclear cogeneration, and these should be funded by public/private partnerships with a strong participation of the industrial sector.
- Awareness and information about the potential of nuclear cogeneration should be further developed and studies should be carried out on the integration of nuclear and renewables using nuclear cogeneration as an energy storage/buffer, including full life cycle assessments.

Annex A. **Benchmarking**

A.1. **District heating benchmark**

*A.1.1. **Nuclear power in Switzerland***

See case study in Section 6.4.

*A.1.2. **District heating benchmarking (Finland)***

Background

The benchmark is a generic case for nuclear district heating in Finland based on the case specification developed by the expert group. The main idea is to have a common generic case study aiming to provide comparable economic results both for nuclear cogeneration and other conventional heat sources.

Calculations were made for typical conventional plants and typical plant sizes in Finland. The levelised cost of heat (LCOH) covers only the cost of these so-called base load plants in heat production, not the overall costs of the district heating network, where peak boilers are also needed to cover the additional heat demand during wintertime and maintenance periods.

- Assumptions for modelled case in Finland

A city with a DH network providing 500 GWh/year (1 800 TJ/year) with a peak demand of 200 MW(th). A nuclear site is located 70/40 km away from the city. Two situations were considered:

1. The nuclear site already exists; it contains two PWR reactors of 502 MWe (Nuclear UPGRADE)
2. A new reactor unit (1 600 MW) is built on the site. The reactor is expected to start before 2030 (Nuclear NEW)

In both situations, the use of nuclear heat implies building a heat transportation system from the nuclear site to the city, whose costs have been considered. It is expected that the cost of a heat transportation system is linear to the distance. The economical calculations should integrate a discount rate of 3.5% according to the European Commission and the technical lifetime of the system is 20 years. Furthermore, the price of CO_2 and electricity in 2030 are expected to be EUR 35/tCO_2 and EUR 50/MWh, respectively. Investment costs are based on European level costs (estimates based on the *IEA/NEA Projected Costs of Generating Electricity, 2015 Edition*) while the other costs apply to Finnish cost levels. Fuel prices and taxes for Finland are used.

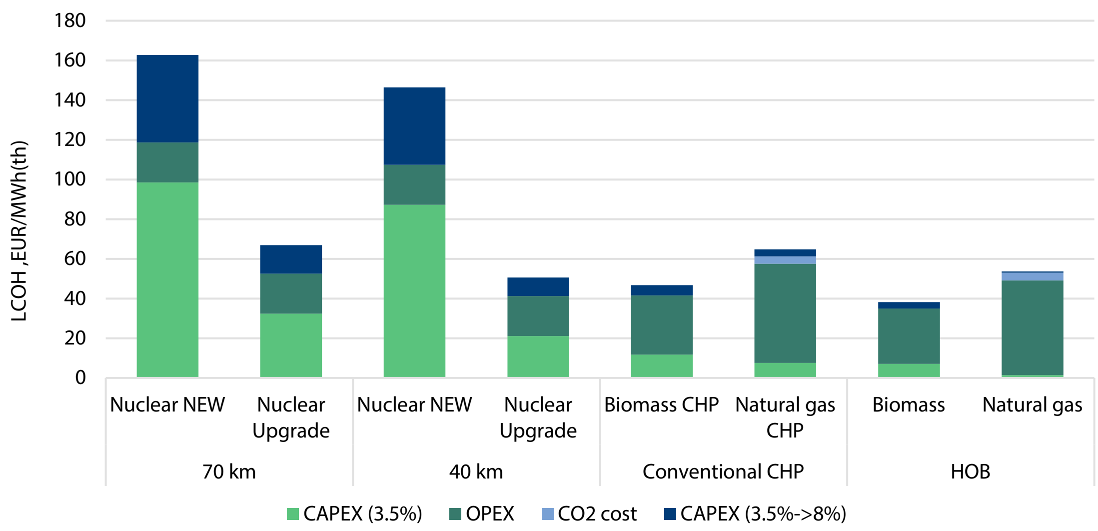
Table A.1: **Calculation results in a Finnish example case, preliminary results**

Parameter	Unit	Nuclear NEW	Nuclear UPGRADE	Nuclear NEW	Nuclear UPGRADE	Biomass CHP	Natural gas CHP	Biomass	Natural gas
Distance to city	km	70	70	40	40	0	0	0	0
Number of units	-	1	2	1	2	1	1	1	1
Heating power	MW(th)	200	200	200	200	100	120	100	100
Load factor (Kp)	%	91 %	91 %	91 %	91 %	85 %	92 %	85 %	92 %
Heat production investment*	M€	500	30	500	30	83	54	50	10
Heat transport system investment	M€	200	200	120	120				
O&M*	M€ / yr	10	10	10	10	15	25	14	24
Carbon emissions	gCO2/kWh						217		217

* Heat production investment and O&M costs depend on how the costs are split between electricity and heat.

Source: Fortum (2016).

Figure A.1: **Levelised in a Finnish case**



Conclusions

Nuclear cogeneration could suit the Finnish energy system, which has a high share of district heated buildings. The district heat connection can be made to the existing nuclear units by steam extraction after high-pressure turbines.

Electricity price developments and the division of costs between electricity and heat will impact the feasibility of heat generation both in nuclear cogeneration as well as in traditional cogeneration. The feasibility of nuclear cogeneration depends on the investment costs, developments in energy markets and the proximity of sufficiently large district heating consumption to the nuclear site.

Nuclear cogeneration could be a feasible option if the DH extraction can be made to an existing nuclear power plant. A high amount of produced district heat combined with sufficiently high energy prices are the most essential factors to economic success.

A.1.3. District heating benchmarking (France)

Two heating systems are analysed and compared: nuclear cogeneration and biomass boilers.

Calculation method

The economic assessment of this benchmark involves the same methods and general assumptions that the Lyon use-case described in Section 6.2 [§ Nuclear District Heating: Economic Study of a Theoretical Retrofit Case (France)]. However, in this section, a carbon taxation equal to EUR 35/tCO_2 is introduced.

Nuclear cogeneration

- Main assumptions

Compared to the hypothesis described in the definition of the benchmark, a few additional complementary assumptions are stated.

The heating power delivered by the nuclear reactor is dimensioned to supply 95% of annual demand, corresponding to a maximum of 120 MWth. The remaining share of demand (5% corresponding to peak load) will be supplied by gas boilers. This complementation of a baseload plant with a peak-load one is a common optimisation that makes it possible to limit the investment costs of the long distance (40 km) heat transportation line from the nuclear plant to the city. The installed capacity of the boilers is enough to cover all the heat loads in case of unexpected outages (on the nuclear plant and/or the transport line).

Both existing nuclear reactors are retrofitted to be able to provide this maximum thermal energy. Extracting the heat on two distinctive reactors instead of one is better both for the security of supply and the optimisation of electricity and heat production within one reactor, considering that:

- the retrofit costs are imposed more by regulatory reasons than purely technical operations, and the regulatory process does not depend much on the number of reactors retrofitted;
- even being high (a few tens of millions of euros), the retrofit costs remain low compared to other investment and operational costs; and
- retrofitting two reactors gives additional security of supply.

The main heat transport system connecting the nuclear power plant to the urban network consists of two 500 mm diameter buried pipelines. The latest insulation technologies make it possible to limit heat losses to below 2% over long distances (up to 100 km with 300 mm polyurethane foam insulation thickness).

The reactor loops are retrofitted in a way to furnish superheated water at 100°C under 15 bars into the transport line. Two pumping stations are required to compensate pressure drops during transport.

The capital cost of the heat transport line is assumed to be EUR 2.5 million/km. This includes the two-way pipeline (with 200 mm insulation thickness), pumping stations and labour cost to install the buried pipelines in rural areas. However, in the sections crossing dense urban areas, this cost could be two to three times more expensive as tunnelling may be needed.

The assumed carbon emissions are 450 gCO_2/kWh for gas and 10 gCO_2/kWh for nuclear.

- Results

The results for nuclear cogeneration-based heating system are gathered in the two following tables:

Table A.2: **Input values for nuclear district heating (France)**

Technology	Parameter	Unit	Value
Nuclear	Number of units	-	2 (1 operating, 1 as backup)
	Heating power	MW(th)	2 x 120 MWth nuclear (95% of the supply) + 200 MWth gas
	Load factor (Kp)	%	24% for 1 reactor, considering the heating purpose only
	Heat production investment	EUR	EUR 110 million
	Heat transport system investment	EUR	EUR 100 million
	O&M	EUR/year	EUR 11 million/year
	Carbon emissions	gCO_2/kWh	31 gCO_2/kWh

Table A.3: **Economic results for nuclear district heating (France)**

Technology	Parameter	Unit	Value
Nuclear	Global investment	EUR	EUR 220 million
	LCOH	EUR/MWh	EUR 53/MWh
	Global carbon emissions	tCO2/year	16 500 tCO_2/year
	Carbon taxes	EUR/year	EUR 0.5 million/year

- Comments

The EUR 120 million of investments for the nuclear heat production are composed of about EUR 40 million of studies and regulatory process, EUR 60 million for the retrofit of the two reactors, and EUR 10 million for the backup gas boilers.

The 31g CO_2/kWh of the new system are mainly emitted by the gas used for the peak load and during reactor outages in the summer. These emissions represent only 16% of the initial production system, allowing savings of around 85kt CO_2/year and giving nuclear heat an economic advantage of EUR 3 million/year compared to conventional fossil fuel heating systems.

Biomass boilers

- Main assumptions

Considering the benchmark as it is defined, biomass technology is not suited to fulfil the required heat production. It is rather to be considered more as a part of a mixed production system together with other technologies like household waste incineration and/or gas boilers. Yet this option is maybe the most promoted currently and needs to be studied. Furthermore, thanks to the characteristic size of its boilers, biomass economic data (like LCOH) remain independent of the share of heat production. The price of wood pellets is assumed at EUR 24/MWh, and carbon emissions at 18g CO_2/kWh.

Even if particles emitted by wood combustion are an issue with this technology, it is supposed that such boilers will be located near the heating network, which avoids the need to build an additional transport line.

Results

Table A.4: **Input values for biomass district heating (France)**

Technology	Parameter	Unit	Value
Biomass boilers	Number of units	-	13
	Heating power	MW(th)	13 x 15 MWth
	Load factor (Kp)	%	28.5% considering a typical heat demand timeline
	Heat production investment	EUR	EUR 75 million
	Heat transport system investment	EUR	EUR 0 million
	O&M	EUR/year	EUR 16 million/year
	Carbon emissions	gCO_2/kWh	18 gCO_2/kWh

Table A.5: **Economic results for biomass district heating (France)**

Technology	Parameter	Unit	Value
Biomass boilers	Global investment	EUR	EUR 75 million
	LCOH	EUR/MWh	EUR 42/MWh
	Global carbon emissions	tCO_2/year	9.000 tCO_2/year
	Carbon taxes	EUR/year	EUR 0.3 million/year

Comments

The economic and environmental results for biomass are challenging. The supply of pellets fuel may become an issue for large capacity boilers (involving about a hundred heavy trucks per week for this benchmark). Particle emissions are another issue from a health point of view, as locating biomass boilers in dense urban areas increases the intake fraction (share of the particles that is inhaled) but locating them farther away would increase capital costs.

A.2. Hydrogen production economic tools benchmark

A.2.1. Benchmarking of economics of hydrogen production (Canada)

Introduction

Producing hydrogen by splitting water using nuclear energy (thermal, electrical or both) is being considered as an important cogeneration application of nuclear energy for GHG reduction. Hydrogen is currently produced mainly using the steam methane reforming process using natural gas both as feedstock and fuel. The steam methane reforming process emits GHGs about ten times the weight of the hydrogen produced. The only method available to produce hydrogen using electricity is conventional electrolysis of water, which is suitable for distributed small-scale production of hydrogen. The high-temperature generation IV reactors that are under development present unique opportunities to produce hydrogen on a large scale. Several technologies, including high-temperature steam electrolysis (HTSE) and a variety of thermochemical cycles, are being developed for hydrogen production using generation IV reactors.

The economics of hydrogen production using HTSE connected to various types of gas-cooled high-temperature reactors using different power conversion cycles has been extensively studied. Harvego et al. (2008) estimated the cost of hydrogen required to obtain a 10% internal rate of return (IRR) for combined HTSE hydrogen plant (183 000 kg/day H_2 output) and a dedicated 600 MWt high-temperature gas-cooled reactor (HTGR) using the Excel-based H2A analysis methodology developed by the US Department of Energy. McKellar et al. (2010) calculated the IRR for a range of hydrogen selling prices for 1.75-1.85 kg/s HTSE hydrogen production coupled with a Rankin steam cycle of a 600 MWt HTGR with outlet temperature of 750°C. The IRR calculations were done through cash flow analysis using Excel and the assumptions about the costs, construction and operating periods, inflation rate, tax rate, debt/equity ratio, interest rate and depreciation are clearly specified. In this study, the economics of hydrogen production using an HTSE connected to a supercritical water-cooled reactor (SCWR) is assessed using two models available in the public domain, namely the G4-ECONS v2.0 (GIF, 2008) and the HEEP (IAEA, 2017). The differences and similarities between the two models are discussed. Further, the cost of hydrogen produced using an HTSE is compared with that of conventional bulk production of hydrogen using natural gas reforming.

Economic tools

Two economic tools, G4-ECONS and HEEP, were used in an economic analysis of hydrogen production using a Canadian SCWR Concept and a HTSE hydrogen generation plant.

In both these applications the nuclear power plant and hydrogen generation plant are defined independently. The look and feel of the applications are different as G4-ECONS is an Excel application and HEEP is a compiled application with a single window interface. HEEP calculations are based on per kg of hydrogen while G4-ECONS uses per m^3 of hydrogen as the basis. The two applications require different economic inputs. Both applications use the power (or heat) credit method for calculation (Taylor and Shropshire, 2009). In the analysis the two applications produced results that were within 1.5% of each other.

Description of G4-ECONS

G4-ECONS (Generation IV Excel Calculations of Nuclear Systems) is an Excel application developed by the Economic Modelling Working Group (EMWG) of the Generation IV International Forum (GIF). It is designed to assess the economics of generation IV nuclear systems against the following two economic goals of GIF.

- The total financial risk of the advanced nuclear energy system should be comparable to other energy projects.
- The advanced nuclear energy system should demonstrate a life cycle cost advantage over other energy sources exists.

G4-ECONS v2.0 calculates a levelised unit energy cost (LUEC) for nuclear power systems, based on the capital, fuel cycle, operating and maintenance and decommissioning costs, and assumes constant expenditure and production profiles over the lifetime of a plant, using a fixed real discount rate. G4-ECONS v2.0 includes a module for calculating a levelised unit product cost (LUPC) for non-electricity applications such as desalination and hydrogen production (GIF, 2008).

G4-ECONS provides a detailed breakdown of results including electrical power and thermal power consumption, electrical and thermal capacity required to support the H_2 generation plant, average costs of thermal and electrical energy, and a breakdown of levelised unit product cost (LUPC) in terms of capital component, non-energy component and energy component.

G4-ECONS uses the power credit method to calculate the LUPC (Taylor and Shropshire, 2009). The power or heat credit method was used by the IAEA, for instance, to evaluate the economics of nuclear desalination. The same method was applied to the economic assessment of small reactors where, for units delivering process heat and electricity, a heat credit is subtracted from total unit costs to establish an equivalent of the levelised costs of producing only electricity.

Description of HEEP

HEEP (Hydrogen Economic Evaluation Program), developed by the IAEA, is a single window-based software which can be used to perform economic analysis of hydrogen production using nuclear energy. The module provides a user-friendly interface to enter the technical details, chronological inputs and cost components of each utility: (a) nuclear energy generation, (b) hydrogen generation and storage, and (c) hydrogen transportation. The execution module calculates the levelised cost for generation, storage and transportation of hydrogen (Khamis and Malshe, 2010). The overall calculation methodology is explained in the user manual (IAEA, 2017). However, unlike the G4-ECONS, formulae cannot be viewed by the user.

The results can be displayed for each of the three modules separately, namely the LUEC for the nuclear power plant, the LUPC for hydrogen, and the unit costs for storage, liquefaction and transportation. HEEP contains libraries of sample nuclear power plants and sample hydrogen plants. New nuclear power plants or hydrogen plants can be added to these libraries. Case studies, which include all specified data for the energy source, hydrogen generation parameters, distribution parameters etc., can be stored in the HEEP library for use by others. These case studies can be reloaded for additional analysis.

HEEP also uses the power credit method, like G4-ECONS, to calculate the LUPC.

HEEP provides the results in a pie chart form as well as a tabular display. The LUPC is broken down by nuclear power plant component, hydrogen generation plant, hydrogen storage and hydrogen transportation. Each of these is further divided into capital cost (debt), capital cost (equity), O&M/refurbishment, consumable cost and fuel cost. In addition to the hydrogen cost details, data is provided on the thermal energy cost details and the electricity cost details.

Comparison/differences between HEEP and G4-ECONS

- Nuclear power plant

G4-ECONS was primarily developed to assess generation IV systems against GIF economic goals; economic assessments of applications such as desalination and hydrogen production were enabled through a separate module. The development and design of G4-ECONS had four goals: simplicity, universality, transparency and adaptability. Simplicity ensures that complex economic modelling is not required. As many of the generation IV reactor systems concepts are still in the early research and development (R&D) stages, economic data may not be well defined, especially in terms of complex year by year cost and revenue as required by some economic models. This is also true for some non-electricity applications. G4-ECONS does not enforce tax structures, discounts rates, etc. of a particular country or region, it has universal application in both developed and developing countries. The use of Excel helps ensure the transparency of G4-ECONS. Users can understand how particular values are derived as all cell formulae are visible. G4-ECONS is adaptable as it is possible to link data entry to external algorithms or data sets specific to a particular generation IV concept.

One of the criteria for G4-ECONS is simplicity so that generation IV reactors that are still under development and for which a lot of detail is not well known can be defined in G4-ECONS. Only a few inputs are required. They include output, capital cost, years to construct, fuel costs (includes material, quantity, reload interval), thermodynamic efficiency, O&M and replacement costs, and expected plant life. Capital cost can be entered as a single rolled up value but can be broken down if greater detail is known. Similarly, additional detail can be provided for the fuel cycle.

To ensure universality, G4-ECONS has a minimum of financial inputs. For the nuclear power plant it allows for a “real discount rate for interest during construction and amortisation, real escalation”, and “fees/royalties”. Real escalation and fees/royalties are defaulted to zero. The real discount rate applies to non-electricity applications as well.

HEEP was primarily developed for economics of hydrogen production regardless of power source. Therefore, HEEP is flexible in the power source. A co-located nuclear power station can be specified, or a remote power source. That is, power from the grid at market prices can be specified. Storage and distribution costs are optional inputs as well. HEEP has three cost components: 1) capital or fixed cost, 2) running costs, and 3) decommissioning costs.

G4-ECONS calculates capital investment during the construction period on a quarterly basis by S-Curve. By default, HEEP spreads out the cash flow as an equal yearly percentage over the construction period; for example, 25% for each year of a four-year construction period. To be consistent, cumulative cash flow percentages for each year of the four years of construction in G4-ECONS; 15%, 35%, 35%, and 15% were used as investments over the four years in HEEP. For simplicity reasons, the O&M costs in G4-ECONS are levelised in constant dollars so that their annual costs remain constant over the life of the plant. G4-ECONS also has a capital replacement cost that is entered as a percentage of the direct capital costs. HEEP does not split these two values out and uses a percentage of the capital costs for O&M calculations. By default, HEEP assumes the costs remain the same for the life of the plant but this can be changed to allow variations in the O&M costs for different years.

The financial inputs for the two applications vary. To simplify the analysis, G4-ECONS uses a real discount rate for interest during construction and amortisation which was set to 5%. Financial inputs for HEEP include discount rate, inflation rate, equity/debt ratio, borrowing interest and tax rate. These rates apply to both the nuclear power plant and hydrogen generation plant. HEEP also allows the user to set the equity versus debt ratio. To be consistent with G4-ECONS, equity was set to 100%; interest rates, the inflation rate and tax rates were set to zero; and the discount rate was set to 5% in HEEP.

HEEP uses a percentage of total capital cost of the facility for decommissioning costs. The costs are considered to be constant over the decommissioning period though HEEP does allow costs to be varied over that period. HEEP defaults the decommissioning period to five years. G4-ECONS expects a projected cost which would include contingency but that excludes interest. This projected cost forms the goal amount for the escrow account accumulated during the operating years by use of a sinking fund with an interest rate the same as the discount rate. G4-ECONS does not include a decommissioning period in the application (GIF, 2008). In the benchmarking analysis, decommissioning costs were set to zero to eliminate any differences due to the different methods of managing decommissioning costs. From the various economic analyses, it is well established that the decommissioning costs are a small fraction of the LUEC or LUPC and, therefore, neglecting the decommissioning costs will not affect the results significantly.

Both G4-ECONS and HEEP break down the LUEC into capital, fuel and O&M components.

- Hydrogen plant

In both G4-ECONS and HEEP, inputs for the hydrogen plants are entered separately from those for the nuclear power plant. The cost of electricity and thermal energy is automatically used from the nuclear power plant module.

In G4-ECONS, the required input for non-electricity applications such as a hydrogen production plant include production output, electrical and thermal energy requirements, capital cost, years to construct, production capacity, expected plant life, O&M, and replacement costs. The unit used for hydrogen calculations is m^3.

HEEP requires few inputs to define the hydrogen production plant and the optional nuclear power plant. The required inputs for a hydrogen production plant are production output, electrical and thermal energy requirements, capital costs, energy usage cost at market rate or a defined nuclear power plant, O&M and decommissioning, and years to construct and operating life. The inputs for a nuclear power plant are thermal rating, heat demand for the hydrogen plant, electricity rating, fuel costs (initial load, annual feed, and cost), capital cost, O&M and decommissioning. HEEP does not provide for a detailed breakdown of overnight costs. Fuel composition can be detailed on a year to year basis. O&M costs can be modified on a yearly basis. HEEP also allows the user to specify if there are multiple nuclear power plants or multiple hydrogen production plants. The unit used for hydrogen calculations is the kg.

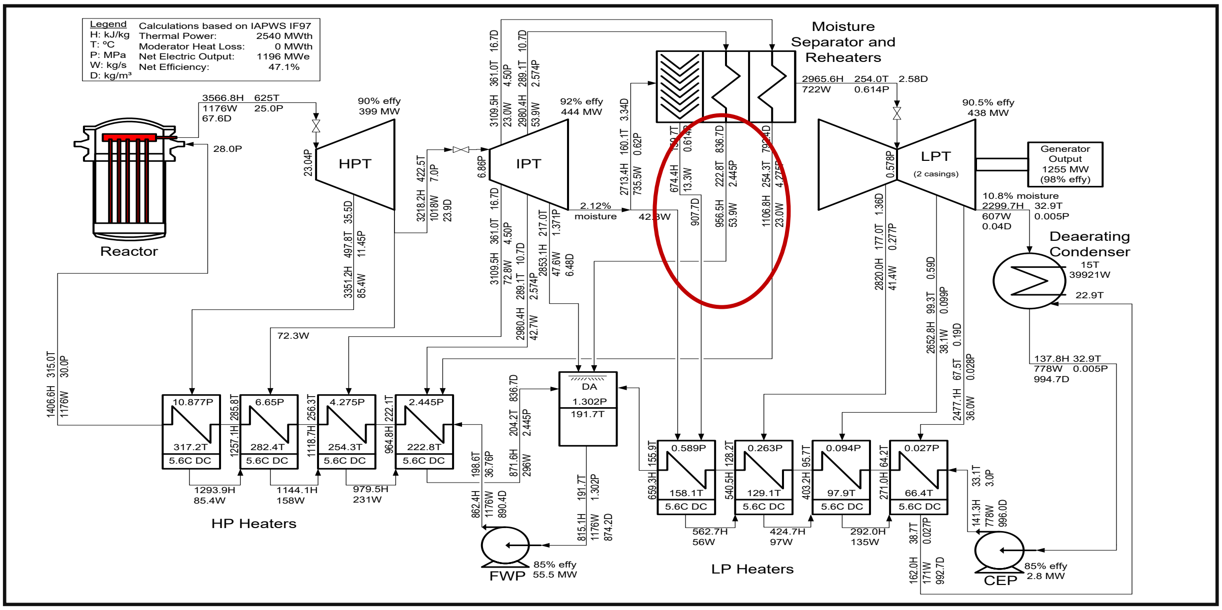
Both G4-ECONS and HEEP break down the unit cost of hydrogen into capital, energy and non-energy components.

Case study for benchmarking of G4-ECONS and HEEP

- Nuclear power plant

The electrical and thermal energy source for the HTSE hydrogen plant is a Canadian SCWR concept nuclear power plant (Schulenberg and Leung, 2016). The SCWR is assumed to be a 1 200 MWe plant with a thermal efficiency of 46.3%. The steam cycle for the SCWR is illustrated in Figure A.2. High-pressure supercritical steam at 25 MPa and 625°C from the reactor core is directly fed into the high-pressure turbine. This direct steam cycle is like that used in boiling water reactors. The balance of the cycle consists of a moisture separator reheater between the intermediate-pressure turbine (IPT) and low-pressure turbine. The steam for the HTSE hydrogen plant heat source is drawn downstream of the 1st stage turbine and is at a temperature of 422°C.

Figure A.2: **Schematic of SCWR direct steam cycle showing location of steam drawn for HTSE hydrogen plant**



Source: Schulenberg and Leung (2016).

Table A.6 and Table A.7 list the inputs for G4-ECONS and HEEP based on the SCWR described in "An Economic Analysis of the Canadian SCWR Concept using G4-ECONS'" (Moore et al., 2016). All costs are in 2007 US constant dollars.

Table A.6: **G4-ECONS inputs for the SCWR concept nuclear power plant**

Input description	Value
Reactor net electrical capacity	1 177 MWe
Reactor average capacity over lifetime	90%
Thermodynamic efficiency (net)	46.3%
Plant economic and operation life	40 years
Years to construct	4 years
Real discount rate for interest during construction and amortisation	5%
Number of fuel assemblies in full core	336
Number of fuel assemblies per reload	112
Average time between refuelling's	0.79 years
Heavy metal mass of fuel assembly	0.1473 MTHM
Purchase or fabrication cost of mixed oxide fuels	USD 3 092.00/kgHM
Total overnight costs	USD 4 000 million
Non-fuel O&M costs	USD 95 million/year
Capital replacements as a % of direct capital	0.10%

Source: CNL (2018).

For HEEP, the nuclear power plant costs are taken from the SCWR analysis done in G4-ECONS and are as follows (Moore et al., 2016).

Table A.7: **HEEP inputs for SCWR concept nuclear power plant**

Input description	Value	Comments
Thermal rating of the nuclear power plant (MW(th)/unit)	2 542	Reactor thermal capacity from reactor portion of G4-ECONS (MW(th))
Thermal power for hydrogen generation (MW(th)/unit)	208.6	This value comes from the hydrogen generation plant and should equal the "heat consumption" value
Electricity output of nuclear power plant (MW(e)/unit) 1	1 080.36	Based on total thermal rating less the thermal power used for hydrogen
Initial fuel load (kg/unit)	49 492.8	Calculated from the number of fuel assemblies in the full core and the heavy metal mass
Annual fuel feed (kg/unit)	20 622	
Overnight capital cost	USD 4 000 million	
Capital cost fraction for generating infrastructure	30%	
Fuel cost (USD/kg)	6 515	
O&M cost (% of capital cost)	2.54	
Decommissioning cost	0	

Source: CNL (2018).

The electricity output is calculated as follows: (thermal rating – thermal power for H_2 generation) * thermodynamic efficiency = (2 542-208.6) * 46.3% = 1 080.36.

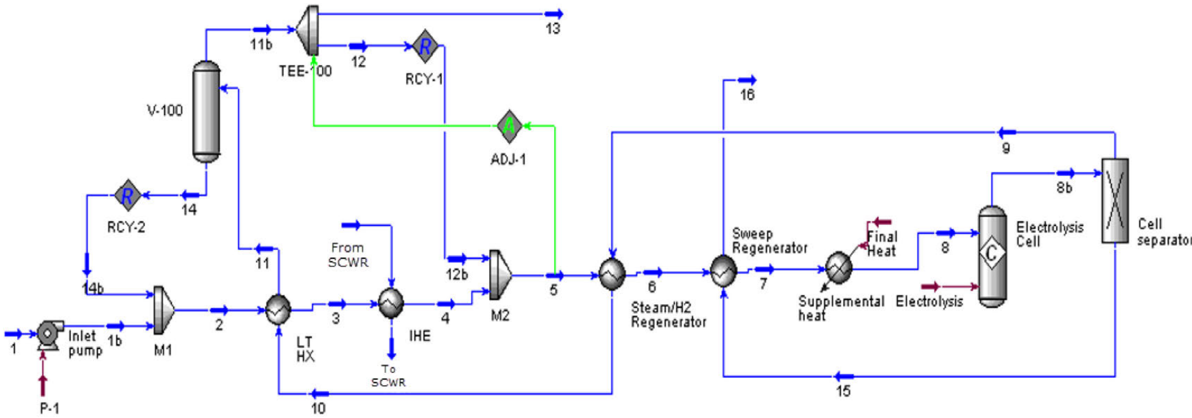
As seen from the comparison of Table A.6 and Table A.7, G4-ECONS and HEEP require different types of inputs for the nuclear power plant calculations. Fuel quantity and unit cost for HEEP were calculated from the fuel inputs for G4-ECONS. Unlike G4-ECONS, HEEP requires the capital cost fraction of the balance of plant to calculate the costs of electric and thermal energies. In G4-ECONS, the electricity and thermal energy costs are calculated based on the reduction in electricity production due to diversion of steam to the hydrogen plant as shown in Table A.8. O&M costs are expressed as a percentage of capital costs in HEEP compared to annualised cost for G4-ECONS. To compare the results on a consistent basis, caution should be exercised to ensure consistency of inputs.

- High Temperature Steam Electrolysis plant

While both G4-ECONS and HEEP provide a library of hydrogen generation plants, the HTSE defined in the G4-ECONS manual (GIF, 2008) was used in this analysis. A large-scale HTSE hydrogen plant, similar in capacity to current natural gas hydrogen plants, supplying hydrogen over the fence to a petrochemical plant was considered for this study. Table A.8 lists the HTSE inputs for G4-ECONS.

A schematic diagram of HTSE process is shown in Figure A.3. Stream 1 contains the liquid water fed to the process. The feed water is at ambient pressure and temperature. The feed water is pressurised and mixed with recycled water. The water is then heated using heat recovered from the product hydrogen and transferred from the SCWR power cycle of the reactor. This heated water is mixed with recycled hydrogen and heated with heat recovered from the hydrogen and oxygen streams. An electric heater is used to heat the water/hydrogen mixture to the required e-cell temperature before entering the cell. The humid hydrogen produced by the electrolysis cell is cooled by passing through two heat exchangers before entering a separator to remove the liquid water. The hydrogen product stream (Stream 13) is saturated with water vapour at 20°C. The oxygen stream produced by the electrolysis cell contains no water vapour. The oxygen is cooled by heat exchange before being exhausted (Stream 16). In the plant configuration shown, the oxygen product stream is exhausted at a temperature of ~500°C (Ryland, 2012).

Figure A.3: **Process flow diagram of HTSE plant**



Source: Ryland (2012).

Table A.8: **HTSE hydrogen plant inputs for G4-ECONS**

Input description	Value
Hydrogen production capacity	1 925 Mm^3 H_2/y
Electricity consumption	4.55 kW(e)h/m^3 H_2
Thermal energy (heat) consumption	0.95 kW(th)h/m^3 H_2
Monetary "value of coolant heat" reduction factor if heat removed post-turbine generator	33%
Economic life of hydrogen plant	40 year
Years to design/construct/start-up (up to ten years allowed)	4 year
Capital cost	USD 700.0 million
Annual operations and maintenance cost for hydrogen plant (excluding energy and capital replacements)	USD 40.0 million/year
Capital replacement/upgrades cost as a % of direct capital costs	3.00%

Using the inputs from Table A.8 and the detailed output information from G4-ECONS, the required inputs for HEEP could be calculated and are presented in Table A.9.

Table A.9: **HTSE hydrogen plant inputs for HEEP**

Input description	Value
H2 generation per unit (kg/year)	1.72 E+08
Heat consumption (MWth)	208.6
Electricity required (MWe)	999.2
Overnight capital cost, USD	7.00 E+08
Other O&M costs (% of capital)	8.7
Decommissioning costs	0

G4-ECONS calculates interest during construction by S-Curve broken into quarters. HEEP allows manual input of % cash flow of base cost on a yearly basis for construction years. G4-ECONS values were converted to cash flows of 15%, 35%, 35%, and 15% for the four years of construction for HEEP inputs.

Energy consumptions in G4-ECONS are specified per unit of hydrogen produced, unlike HEEP which requires the electric and thermal capacities of the nuclear power plant required for hydrogen production.

HEEP does not require the capital replacement/upgrades cost. Therefore, to be consistent with G4-ECONS, the replacement cost was included in the O&M cost for HEEP.

Decommissioning costs were set to 0 for both G4-ECONS and HEEP.

G4-ECONS has a single input for interest/discount rates, "real discount rate for interest during construction and amortisation over the operating life of the plant", defined for the reactor that is also used for the hydrogen plant calculations. Therefore, for HEEP, a value of 5% was also used for the real discount rate. HEEP requires several inputs that do not have an equivalent in G4-ECONS, and these were set to zero.

Table A.10: **Economic inputs for HEEP**

HEEP	Value	Field in G4-ECONS
Discount rate (%)	5	"Real discount rate for Interest during Construction and Amortization"
Inflation rate (%)	0	Not available in G4-ECONS
Equity (%)	100	Not available in G4-ECONS
Debt (%)	0	Not available in G4-ECONS

For both HEEP and G4-ECONS a four-year construction period and a 40-year operating period were used. The depreciation period in HEEP was set to 40 years as well. HEEP assumes the same construction and operating period for both the nuclear power plant and the hydrogen plant. G4-ECONS allows for separate entries for the nuclear power plant and the hydrogen plant.

Refurbishment costs were set to zero for both G4-ECONS and HEEP.

- Results

The resulting LUPC for hydrogen production with a co-located nuclear power plant and a hydrogen plant are USD 3.61/kg for G4-ECONS and USD 3.56/kg for HEEP. There is only a 1.4% difference between the two estimates.

Table A.11: **Benchmarking results for G4-ECONS and HEEP**

	G4-ECONS	HEEP
H_2 unit cost, USD/kg	3.61	3.56
Cost breakdown		
H_2 plant capital component	0.27	0.28
H_2 plant non-energy component	0.39	0.39
H_2 plant energy component	2.95	2.89

Varying the capital costs, electrical requirements and thermal requirements

Further comparison between HEEP and G4-ECONS was conducted by varying several inputs – capital costs, electrical energy requirements and thermal energy requirements. A literature survey revealed that the energy consumption for HTSE process could be significantly lower than those assumed in the above analysis. Electrical energy requirements in the range of 30 to 35 kWh(e)/kg have been reported in Harvego et al. (2008), McKellar et al. (2010), Ryland (2012) and Harvego et al. (2012) compared to 51 kWh(e)/kg assumed in the above analysis based on the information from G4-ECONS User's Manual (GIF, 2008). Therefore, for the purposes of sensitivity of the two economic tools to varying inputs, a range of electricity requirements (30-35 kWh(e)/kg) was used. Similarly, thermal energy requirements were varied in the range of 5.3 kWh/kg to 10.1 kWh/kg.

Capital cost was varied over the range of 70% to 150% of the value (USD 700 million) used in the above analysis. Since HEEP calculates O&M as a percentage of capital costs it was necessary to adjust O&M costs in G4-ECONS so that the percentage remains constant. The range of inputs used to compare the two economic tools is listed in Table A.12.

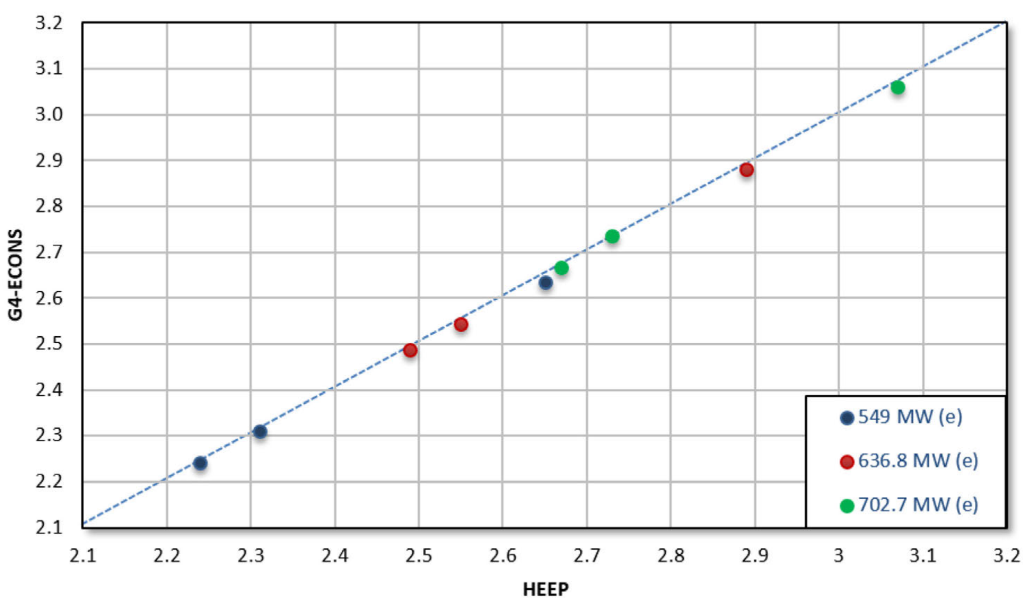
The range of electrical and thermal values used in this analysis is lower than required by the HTSE defined in G4-ECONS, resulting in excess electricity being available from the nuclear power plant for sale to the grid.

The results varied from a .025% difference to a 1.5% difference between G4-ECONS and HEEP. Figure A.4 below shows the differences between HEEP and G4-ECONS for a constant thermal input but with the capital costs and electrical energy varied.

Table A.12: **Varied inputs to G4-ECONS and HEEP**

	Low	Medium	High
H_2 plant capital costs	USD 630 million	USD 700 million	USD 1 050 million
Electrical energy requirements			
HEEP	549 MW(e)	636.8 MW(e)	702.7 MW(e)
G4-ECONS	2.5 kWh/m³	2.9 kWh/m³	3.2 kWh/m³
Thermal energy requirements			
HEEP	103.2 MW (th)	147.1 MW (th)	197.6 MW (th)
G4-ECONS	0.47 kWh/m³	0.67 kWh/m³	0.90 kWh/m³

Figure A.4: **HEEP versus G4-ECONS results with varying capital cost and electrical energy consumption at a constant thermal energy requirement**



Comparison with steam methane reforming

More than 80% of the industrial hydrogen in the world is produced by steam methane reforming using natural gas as both the feedstock and the fuel. Steam methane reforming is also the most effective way of producing hydrogen in large quantities on site for use in the production of ammonia or for upgrading crude oil. Hydrogen is used in the oil industry for cracking of crude oil. The cost of producing hydrogen using steam methane reforming is largely dependent on the cost of natural gas. Hydrogen produced by an HTSE coupled with an SCWR would need to be competitive with steam methane reforming.

Cost of hydrogen using H2A

In an in-house study done by Canadian Nuclear Laboratories in 2005, the cost of a large-scale hydrogen plant with a nominal capacity of 483 000 kg/day (200 million standard cubic feet per day) was estimated to be USD 351 million taking into consideration the higher costs of construction in the oil sands location in northern Alberta, Canada. This plant would require 90 300 GJ/day of natural gas, 4.8 MW electricity, and would produce 3 450 t/day of steam as by-product and emit about 4 730 tons/day of CO_2. The steam methane reforming process produces about 10 tons of CO_2 per ton of hydrogen, and therefore would be subject to an applicable carbon tax. The information was used in the Excel application H2A to estimate the cost of producing hydrogen for a range of prices of natural gas. The results are shown in Figure A.6. A steam credit of USD 15/ton would be offset by a carbon tax of USD 7.3/ton. Therefore, both a carbon tax and steam credit were not considered in the H2A calculation.

The H2A Production Model is an Excel application developed by the National Renewable Energy Laboratory (NREL). It analyses the technical and economic aspects of central and forecourt hydrogen production technologies. H2A uses a standard discounted cash flow rate of return methodology to determine the minimum hydrogen selling price (Steward et al., 2012).

Table A.13: **H2A inputs**

Operating capacity factor	90.0%
Plant design capacity	525 300 kg of H_2/day
Plant output	472 770 kg/day
Construction period	4 years
Plant life	40 years
After-tax real IRR	5.0%
Capital cost	USD 351 000 000
O&M	USD 14 220 000/year
Other variable operating costs	0.50% of total direct depreciable costs per year

The results of the H2A analysis are shown in Figure A.6. The cost of hydrogen varies linearly with the price of natural gas as shown in Figure A.6.

Uncertainty in hydrogen costs

Additional analysis of the cost of hydrogen production was done using HEEP by varying the discount rate and the capital cost for the SCWR. As thermal energy contributed very little to the cost, it was excluded from the analysis.

Table A.14: **Inputs for additional analysis for comparison with steam methane reforming**

HEEP inputs	Low	Medium	High
SCWR capital cost	USD 3 600 million	USD 4 000 million	USD 5 200 million
HTSE capital costs	USD 630 million	USD 700 million	USD 1 050 million
Electrical energy requirements	549 MW(e)	636.8 MW(e)	702.7 MW(e)
Discount rate	5%	7.5%	10%

The hydrogen unit cost (LUPC) was calculated for each of the 81 cases with different combinations of the inputs described in Table A.14. It was assumed that each case has equal probability. The cumulative probability plot was constructed as shown in Figure A.5. The LUPC varied from a low of USD 2.13/kg hydrogen to USD 5.17/kg hydrogen. The light grey section in Figure A.5 represents the 80% confidence interval. There is only a 10% chance that the cost of hydrogen production for the HTSE coupled with an SCWR will be lower than the lower bound of USD 2.52/kg hydrogen, and there is only a 10% chance that the cost of hydrogen production would be greater than the upper bound of USD 4.28/kg hydrogen. The centre is the mid-point value of USD 3.24/kg hydrogen and is marked by the red line.

The upper and lower bound values and the mid-point of the 80% confidence interval of the hydrogen costs were marked by red lines in Figure A.6 to find the corresponding natural gas prices at which nuclear hydrogen production is competitive with steam methane reforming. At the lower end of the 80% confidence interval the LUPC is USD 2.52/kg hydrogen (Figure A.5), which corresponds to a natural gas price of USD 12.03/GJ. At the upper end the LUPC is USD 4.28/kg hydrogen and the corresponding natural gas price is USD 21.31/GJ. The LUPC at the mid-point of the confidence interval is USD 3.24/kg hydrogen which corresponds to a natural gas price of USD 15.83/MMBtu.

Figure A.5: **Cumulative probability curve for HTSE/SCWR hydrogen production costs**

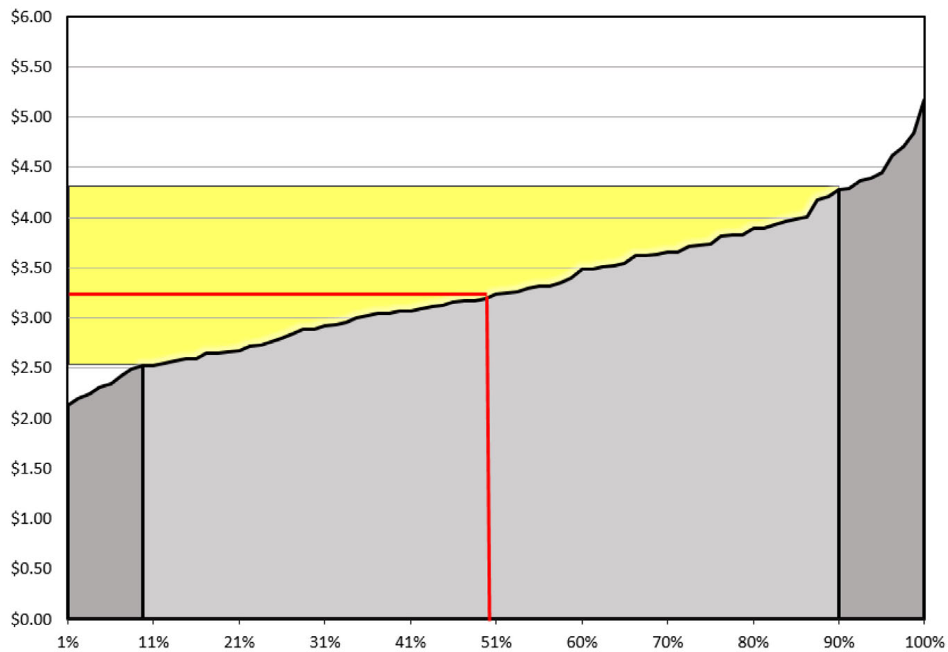
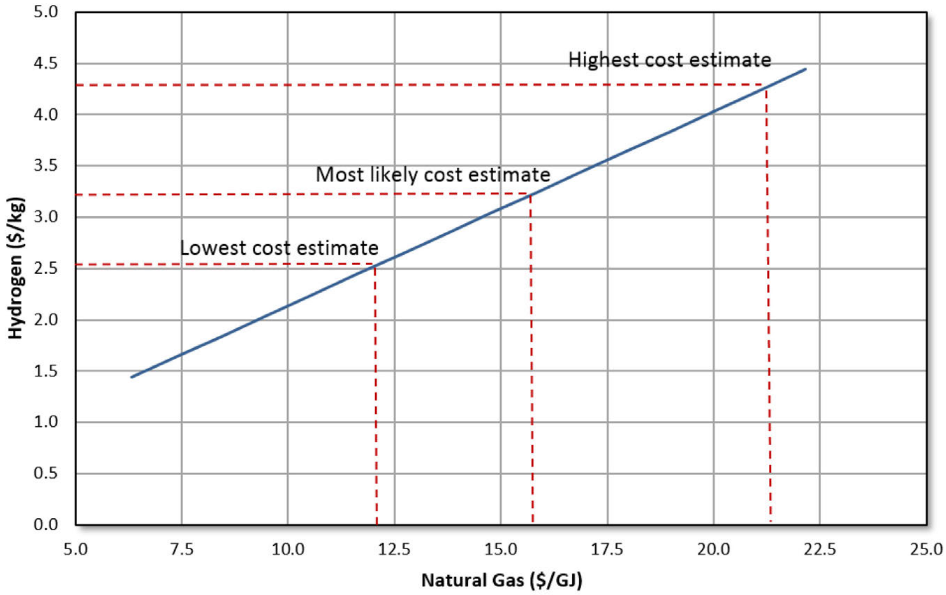


Figure A.6: **Cost of natural gas versus cost of hydrogen**



Conclusions

The cost of hydrogen produced by HTSE process coupled with a SCWR reactor estimated by the two economic tools, G4-ECONS and HEEP, was found to be comparable. Varying the capital cost of the hydrogen plant and electrical energy requirements gave similar hydrogen costs for both G4-ECONS and HEEP; the maximum difference of 1.5% was observed over the entire range of values. Nuclear hydrogen costs were then compared with the cost of hydrogen using the conventional steam methane reforming process estimated by the H2A model. The uncertainty in the cost of nuclear hydrogen was evaluated over a range of capital costs for nuclear and hydrogen plants, electrical energy consumption for hydrogen, and discount rates. The 80% confidence interval of the nuclear hydrogen cost was found to be rather large, with USD 2.52/kg as the lower bound and USD 4.28/kg as the upper bound of the cost. This analysis shows that for nuclear hydrogen to be competitive, the natural gas price must be about USD 15/GJ. This analysis was done in 2007 constant USD for a North American location. The natural gas price in 2007 was higher than in 2016 in North America. The natural gas price in East Asia tends to be significantly higher than in North America. Also, the cost of construction of nuclear plants and associated hydrogen plant would vary with the region. Therefore, the economics of nuclear hydrogen production should be considered in the regional context.

A.3. **Benchmarking for nuclear hydrogen production cost**

This section provides a summary of the benchmarking case study whereas the details of the related cost estimation can be found in Section 6.6 of this report.

*A.3.1. **Reference system***

- The system is a centralised large-scale nuclear hydrogen cogeneration production system sited in Japan.
- Hydrogen is produced and supplied to an adjacent industrial user (e.g. oil refinery or chemical plant) on the site.
- Alternatively, an at-gate cost is also given for liquefied and stored hydrogen product, ready to be transported by pipeline or trucks to the users.

- The type of hydrogen production process selected for nuclear hydrogen production is the thermochemical sulphur-iodine process being the Case 2 as defined in Section 6.6.3 of this report.
- The type of nuclear reactor considered for this case study is the VHTR cogeneration system of GTHTR300C as described in Section 6.6.1.

A.3.2. *Benchmark inputs*

Nuclear reactor:

- Thermal rating (MWth) 600 MWt
- Thermodynamic efficiency (%) 50.4% power generation
- 50.2% hydrogen production
- Electrical rating (MWe) 204 MWe
- Capacity factor (%) 90%
- Overnight capital cost (USD million) USD 456 million
- Construction period (years) 4 years
- Fuel cost (USD/MWh) USD 10.9/MWh
- O&M costs (USD/MWh or % of capital cost) USD 7.4/MWh
- Decommissioning cost (% of capital cost) USD 1.4/MWh (0.7% of capital-year)
- Financial assumptions (discount rate, depreciation/amortisation rates etc.)
  - Plant lifetime 40 years
  - Depreciation period 16 years
  - Residual value 10%
  - Discount rate 3%
  - Interest rate 3%
  - Property tax rate 1.4%

Nuclear hydrogen plant:

- Hydrogen production (kg/year) 22 500 000 kg/year
- Thermal energy required (MWth, or, kWh/kg) 170.0 MWt
- Electricity required (MWe, or, kWh/kg) 27.5 MWe
- Overnight capital cost (USD millions) USD 427 million
- O&M costs (% of capital cost, or, USD/kg) USD 0.21/kg-H2
- Decommissioning cost (% of capital) 10%/capital

Hydrogen Storage and Transportation

- Storage capacity (kg) 26 915 kg
- Compressor/liquefier electricity requirement (kWe) 277 000 kWe
- Overnight capital cost (USD millions) USD 2 127 million
- Operating cost (% of capital cost) USD 122 million (5.7%/capital)

A.3.3. *Benchmark results*

Nuclear hydrogen unit cost (USD/kg) should be presented in the following cost components

- Capital cost (include only hydrogen plant capital cost, USD/kg) USD 0.58/kg
- Energy cost (total and breakdown between thermal and electrical energy, USD/kg)
- Total USD 1.47/kg
- Electrical energy USD 0.31/kg
- Thermal energy USD 1.16/kg
- Other operating costs for hydrogen plant (USD/kg) USD 0.21/kg
- Cost of H_2 production (USD/kg) USD 2.26/kg
- Cost of H_2 onsite liquefaction/storage (USD/kg) USD 0.65/kg
- Cost of liquefied H_2 product at gate (USD/kg) USD 2.91/kg

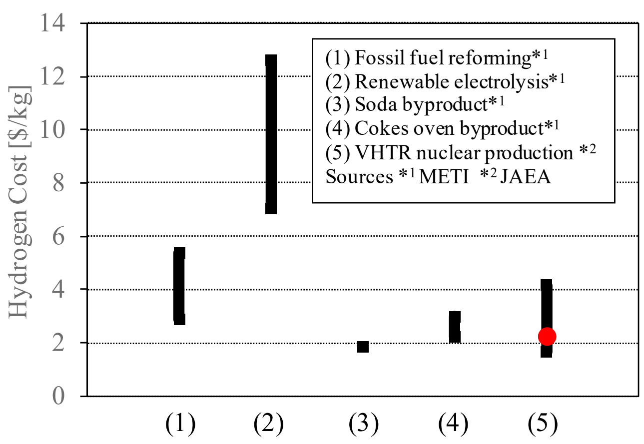
The levelised unit electricity cost and thermal energy costs for nuclear plant should also be presented as follows:

	Electricity	Thermal energy
• Capital cost (USD/MWh)	USD 11.6/MWh	USD 8.2/MWh
• Fuel cost (USD/MWh)	USD 12.2/MWh	USD 5.6/MWh
• O&M cost (USD/MWh)	USD 8.2/MWh	USD 5.7/MWh
• Total cost (USD/MWh)	USD 32.0/MWh	USD 19.4/MWh

A.3.4. *Comparison with current alternatives*

Figure A.7 compares the benchmark cost (a marked point under category (5) of VHTR) of nuclear hydrogen production with those of the current conventional methods practised in Japan. The latter are referenced costs reported by the METI (2015).

Figure A.7: **Cost comparisons of hydrogen production method alternatives**



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Beyond Electricity: The Economics of Nuclear Cogeneration

Nuclear energy is an important source of low-carbon electricity and thus plays a significant role in avoiding carbon emissions. It has the potential to decarbonise the global energy sector even further by also providing heat for industrial applications and residential heating, which both continue to run mainly on fossil fuels. More than 65 nuclear reactors around the world (about 15% of the total) with decades of experience demonstrate on a daily basis the feasibility of providing non-electric applications of nuclear energy such as district heating, desalination or other forms of process heat.

In order to further reduce carbon emissions, the share of nuclear reactors used for cogeneration needs to be expanded. However, until recently the economic competitiveness of thermal energy produced by nuclear power plants has been a challenge. Not accounting for climate change impacts, heat produced by gas- or coal-fired power plants has frequently been cheaper. Yet, as fossil fuel prices rise and carbon costs are increasingly accounted for, the economics of nuclear cogeneration begin to look more favourable. A good understanding of the technical realities and economics of nuclear cogeneration, including its implications for electricity and energy systems, is essential to take advantage of this changed environment. This NEA report provides a thorough overview of nuclear cogeneration, with a view to helping energy decision-makers and interested experts in assessing the costs and benefits of having nuclear energy provide both low-carbon electricity and low-carbon heat.

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