4.5 **ON THE ROLE AND ECONOMICS OF NUCLEAR COGENERATION IN A LOW CARBON ENERGY FUTURE**

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1. **Introduction, purpose of the study**

The world’s nuclear reactor fleet as of 1 March 2012 consisted of 436 reactors, essentially Light Water Reactors (LWRs), representing an overall capacity of 370 GWe. These nuclear reactors generate about 13% of the world’s electricity, and play a significant role in the reduction of greenhouse gas emissions (GHG) from the power sector. Replacing them by fossil-fired generation units would represent additional emissions of 2.6 Gt CO$_2$ (if replaced by coal) or 1.3 Gt CO$_2$ (if replaced by gas), increasing the emissions from the power sector by 22% or 11% respectively [NEA, 2012]. Most of the nuclear expansion that is foreseen up to 2050 in scenarios that aim at decarbonising the energy sector - up to 1100 GWe in 2050 according to the 2DS scenario of the IEA [IEA, 2012] - is essentially composed of large electricity-generating LWRs, with typical units in the range 1000 MWe to 1750 MWe.

A further contribution to the decarbonisation of the world’s energy sector can be made by the use of 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 which today run on
fossil fuel (coal, oil, gas) or biomass. With increasing demand for freshwater, and demand for transportation fuel that could be extracted and generated from large resources of heavy oils and bitumen using steam and hydrogen, the GHG emissions from fossil-based cogeneration are set to increase, unless low carbon technologies such as nuclear energy can be used. The feasibility of non-electric applications of nuclear energy has already been demonstrated, as shown in Figure 1, with about 74 reactors (about 17% of the world’s fleet) providing either district heating, desalination or some other form of process heat. It is not clear, however, how economically justified these examples are, since most were developed in former Soviet countries.

**Figure 1. Number of nuclear reactors involved in non-electrical applications (desalination, district heating and process heat) [IAEA, 2011]**

Depending on the application, different types of reactor technologies may be required, from LWR typically operating at temperatures around 300 °C, to liquid-metal cooled reactors (LMR) operating at around 500 °C up to gas-cooled high temperature reactors (HTR) operating at temperatures in the range 700-1000 °C. Recently, a class of reactors known as SMRs has been attracting a lot of attention. This abbreviation can represent either Small and Medium-size Reactors (IAEA terminology) or the more advanced Small Modular Reactors (US DOE terminology) that are being developed in several countries such as the United States. There are SMRs of different technology (LWR, LMR 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. Figure 2 shows the types of applications that can be targeted depending on the temperature of the steam produced by nuclear reactors.
However, non-electric applications of nuclear energy will only develop if nuclear cogeneration is more economical than the technical solutions it replaces, essentially gas-fired production of steam and electricity. Hence a good understanding of the economics of nuclear cogeneration, including the associated system costs, is essential. A recent publication by Carlsson et al. [Carlsson, 2012] looked precisely at the competitiveness of SMRs in future European cogeneration market using the so-called target cost methodology. It is one of the main purposes of the proposed study to review existing studies and propose a common methodology to assess future applications.

Finally, in addition to the supply of non-electric products, cogeneration offers the potential for load-following services in electricity supply systems that have large shares of intermittent technologies. These services consist of energy storage and peak electricity production using nuclear-generated hydrogen. Such services will be increasingly needed in countries that are planning large scale deployment of renewable power technologies (solar or wind). Because of their intermittency, back-up power is required, and in practice, this is often based on fossil-fired power generation. The case has already been made that low-carbon cogeneration could assist in balancing electricity production from variable renewable through thermal storage [IEA, 2011a] or hydrogen production, storage and use in wind power production [Stiller, 2010]. Nuclear-based production of hydrogen could also be considered as a way of dealing with the intermittency of renewables, in a way that would allow nuclear reactors to operate at their economic optimum, namely baseload [Forsberg 2006, 2012, NREL 2011, 2012]. The rationale and economic justifications for these so-called “nuclear hybrid energy systems” which support the synergy between nuclear energy and renewable power technologies will be reviewed in the study.

2. Interest in nuclear cogeneration

In this section, current or recent research activities on non-electric applications of nuclear energy will be briefly reviewed. Then, an assessment of the potential markets and “time to market” of such applications will be made on the basis of recent publications, to support the need for an NEA study on the subject.
2.1 NEA member state research activities on nuclear cogeneration

A high number of NEA countries have been working on nuclear cogeneration applications over the past decade, and have gained valuable experience. Hydrogen generation from nuclear reactors in particular has been the object of major research efforts, to a large extent in relation with the development of Generation IV reactor technologies [NEA 2006, 2010]. Below are examples of some nuclear cogeneration studies carried out by these countries.

- Canada had a significant nuclear hydrogen programme [Naterer, 2010], motivated in part by the potential to generate synthetic fuel from the huge bitumen reserves contained in the Alberta oil sands. Nuclear reactors [Rolfe, 2007, Oberth, 2009] providing steam and electricity, and enabling the production of hydrogen necessary for the upgrade of the fuel, represent low carbon alternatives to gas-fired cogeneration processes currently used [Larsen, 2004].

- Finland, which has a long tradition of district heating using fossil fuel and now increasingly, biomass, has also looked at district heating from nuclear power plants. During the application process for a “decision in principle” on a new reactor at the Loviisa site situated about 100km from Helsinki, the utility FORTUM commissioned a feasibility study on nuclear district heating [Bergroth, 2009]. The decision in principle for Loviisa 3 having been negative, the subject was no longer pursued, but could be of interest again in the event the existing reactors, Loviisa 1 and 2, are replaced by new units around 2030.

- France has also looked at the feasibility of connecting existing district heating networks (in Paris and in Lyon) to neighbouring nuclear power plants. A first study [Le Pierres, 2009] looked at transport of heat from the Bugey nuclear power plant to Lyon, while more recent studies performed by CEA [Safa, 2011, 2012] have addressed the feasibility and economics of transporting heat from Nogent-sur-Seine nuclear power plant to the Paris district heating system. The CEA has also carried out a lot of research and development on hydrogen generation from nuclear reactors [Yvon, 2010].

- Germany, which had a pioneering role in the development of HTR technology, also investigated the potential for delivery of high temperature heat for industrial applications such as coal gasification and hydrogen production. An overview of the country’s 20 year involvement in HTR research is given in [von Lensa, 2010].

- Japan has a long experience of using desalination to provide process water for the operation of its thermal power plants, including some nuclear power plants [Maciver, 2005]. Furthermore, within the programme for developing high temperature reactor technologies and the operation of the HTTR prototype, Japan has demonstrated the feasibility of nuclear hydrogen production using thermochemical iodine/sulphur (I/S) cycles.

- Korea has developed both nuclear desalination applications for the new SMART SMR reactor [Park, 2011], and nuclear hydrogen production applications using high temperature reactor and I/S cycles within the Nuclear Hydrogen Production Technology Development (NHDD) programme [Chang, 2010].

- The NRG Company in the Netherlands has been involved in HTR and nuclear cogeneration research for more than a decade, with its own conceptual design of the ACACIA HTR reactor to the coordination of European R&D efforts on nuclear cogeneration in the frame of the FP7 Euratom ARCHER project (Advanced High-Temperature Reactors for Cogeneration of Heat and Electricity R&D).
The case of Poland is very interesting. Although the country does not yet have any nuclear power plant, it has plans for constructing a first nuclear reactor to be in operation in the 2020s, and, given the huge coal reserves of the country, it is also very interested in synthetic fuel fabrication through coal gasification [Pienkowski, 2008].

Russia has a long experience of operating district heating using heat provided by nuclear power plants [Krivitskii, 2005]. It was also one of the first countries to demonstrate the process of desalination using nuclear heat and electricity, at the Aktau (formerly Shevchenko) site in Kazakhstan, on the Caspian sea (salty water) where between 1973 and 1993, a sodium-cooled fast reactor of BN-350 type was used to produce electricity and up to 120,000 m³ fresh water/day [Konishi, 2009].

The United States has been pursuing the development of high temperature reactor technology within the Next Generation Nuclear power Plant (NGNP) programme, which targets hydrogen production and supply of process heat to the industrial sector [INL, 2011]. Research has also been performed on so-called “nuclear hybrid energy systems” [NREL, 2011, 2012, Forsberg, 2006, 2012]. The underlying concept is to provide load-following electrical power to match intermittent power generation from renewable, while maintaining full rate operation of the nuclear reactor. When power demand is low, the thermal energy of the reactor could be diverted to make synthetic fuel such as hydrogen. This topic will be further discussed below.

2.2 IAEA activities on process heat applications

The IAEA has carried out projects on nuclear cogeneration (desalination, district heating or hydrogen production) for many years [IAEA, 2002, 2007, 2009, 2011, 2012]. Maximum use of published study results will be made in the proposed study, which aims at identifying complementary issues that could be of interest to and benefit from the contributions of NEA member countries.

2.3 Cogeneration markets & time to market

There are several reasons why nuclear cogeneration is limited today to a few reactors in operation – fewer than 20% of the current fleet today produce more than just electricity. Some of the reasons are of technical or regulatory nature. But one of the main reasons is that the different markets for nuclear cogeneration are not clearly defined. To be precise, there are many applications that could be technically fulfilled using heat and electricity supplied by nuclear reactors, but the economic bases of these applications are not established.

The vision of the “hydrogen economy” that seemed to be in the making at the beginning of the last decade did not materialise, postponing the need to develop large production facilities. There are probably many technical or regulatory reasons why hydrogen has not yet emerged as a widespread fuel in spite of more than a decade of research and development efforts, but it is likely that compared to the fossil fuel it was supposed to replace, the cost drivers were not favourable to hydrogen. However, in the long term, it is still considered a potential substitute to fossil fuel, mainly for transport applications. In its decarbonisation “2DS” scenario [IEA, 2012], the IEA sees hydrogen playing an important role, in the period 2050-2075, as a fuel for transport. In the mid to long term, it could also replace fossil fuel-based feedstock and energy in the chemical sector, for the production of ammonia, methanol, ethylene and propylene. Of course, the production of hydrogen will need to be decarbonised – and nuclear energy could play an important role in that respect.

The Russian Federation will officially become the NEA’s 31st member country on 1 January 2013.
77. A reliable assessment of the market size for nuclear cogeneration requires a reliable assessment of the economics of the applications. The price of fossil fuel, oil or gas, plays a major role in determining the time to market of these applications, but also brings a high level of uncertainty to any predictions that can be made. Earlier assessments of the market for non-electric applications of nuclear energy [IAEA, 2002, NEA, 2004], as well as the more recent assessments described below (related more to HTR applications) need to reviewed in the light of reliable economic studies.

78. According to [INL, 2011], 60% of the energy consumption for the chemical industry in the United States is used for feedstock, typically in the form of natural gas. In the same report, an analysis is made to determine what would be the market (in the United States) for which HTRs could be an economical alternative (under certain assumptions on capital and operating costs, as well as on costs on carbon emissions). The report finds that HTRs could be competitive for industrial plants requiring 900 MWth or more (even without a cost on carbon), and for those between 600 MWth and 900 MWth with a cost on carbon. 105 cogeneration plants are rated above 900 MWth, representing a total capacity of 156 GWth. Replacing half of them by a nuclear plant would represent a market of about 75 GWth, or 125 units of 600 MWth capacity.

79. The INL study [INL, 2011] (as well as an earlier ANL study [ANL, 2005]) also looks at the market for nuclear-generated hydrogen, and in particular, at the so-called merchant market, which represents about 20% of the direct production of hydrogen in the US. Steam methane reforming is the principal method for producing hydrogen, with significant CO\textsubscript{2} emissions unlike the high temperature steam electrolysis (HTSE) or the thermo-chemical cycles technologies that can be deployed with a HTR. The hydrogen merchant market, which has not grown because of the economic recession, is still predicted to grow at rates between 8 to 17% per year. The report makes a more conservative assumption, 5% per year, and assumes that a quarter of the new production units will be met using nuclear-based HTSE. This would represent 36 GWth of capacity – about 60 units of 600 MWth, over the period 2020-2050.

80. Other potential markets for nuclear cogeneration include:

- The production of steam necessary for the extraction of bitumen from the Canadian oil sands, and the upgrade of the bitumen to synthetic fuel with the addition of hydrogen (generated by the nuclear plant).

- The production of synthetic fuel from coal, using variants of the Fischer-Tropsch process. This process was developed by Germany during the 2\textsuperscript{nd} World War, and then used by South Africa during the Apartheid era as it could not import oil due to international sanctions. This application remains of interest to countries that have large coal reserves such as Poland [Pienkowski, 2008], and for those that wish to limit dependency to oil imports. Reducing the US oil imports by 25% for instance would require the heat and hydrogen produced by about 415 HTR units of 600 MWth [INL, 2011].

81. Studies on the potential market for nuclear cogeneration were also performed in Europe. For instance, in [Bredimas, 2011a], a survey of the European heat market carried out in the frame of the EU-funded EUROPAIRS project is reported. This heat market is large, representing between 290 and 350 GWth. 30% of this market is a so-called “plug in” market, which could be targeted by heat-producing nuclear reactors, and represents about the capacity of about 170 reactor units of 500 MWth. While recognising that nuclear production of hydrogen has not be demonstrated at industrial scale yet, the presentation makes a case for this application, given Europe’s already existing H2 pipeline system (the most extensive in the world) which could benefit from a large scale production units.

82. Under certain conditions (for instance cost of carbon emissions), electricity from HTRs could also be competitive with respect to fossil-based generation. It is to be noted that the HTR-PM reactor to be
build in Shidaowan, China – 2 reactor units connected to a 210MWe turbogenerator – will only be used for electricity generation.

3. Cost drivers for nuclear cogeneration

83. The size and type of a nuclear reactor (LWR, HTR or LMR), its operating conditions (thermal output, temperature and pressure of the working fluid), its location (distance from industrial sites or district heating networks) determine what type of non-electric applications can be considered. To have a good understanding of what would be the underlying economic principles of a nuclear cogeneration plant, it is necessary to understand what type of services it can provide, what are the requirements from the application, and what are the cost targets given by the operation of the fossil-fuel application it would replace (and whether some form of carbon price exists that would reduce the competitiveness of the latter). Then, there are constraints related to the coupling of a nuclear power plant with an industrial application which need to be taken into account.

3.1 Requirements from the cogeneration application

84. As an example, the characteristics of a nuclear cogeneration HTR was determined on the basis of existing (fossil-fired) industrial cogeneration plants in the United States [INL, 2011]:

- the plant must be able to supply steam demand at 100% availability; on average the steam demand if 55% of the total energy demand on the CHP plant;
- the peak to average demand of total energy is 120%;
- the plant must be able to supply at least 45% of its energy in the form of electricity; 25% of the electricity will be sold off-site (this is the primary mechanism to absorb variations in the energy demand from the industrial plant);
- At least 90% availability on an annual basis is required for the nuclear plant.

3.2 Cost drivers related to the nuclear power plant

85. The cost of the nuclear power plant, especially if one is considering a First Of A Kind (FOAK) of a technology, is of course a major cost driver of nuclear cogeneration. Thus for projects involving high temperature reactors, in spite of past experience in the operation of power reactors in the 1970s and 1980s (Fort Saint Vrain in the United States, and THTR 300 (Thorium HighTemperature Reactor) in Germany, there remains a large uncertainty in capital and operating costs of a new HTR [INL, 2011].

3.3 Cost drivers related to the coupling

86. The cost of cogeneration equipment (heat exchangers) and design changes to traditional turbine halls of nuclear power plants, the cost of transport of heat in special piping that limit losses need to be taken into account, as well as the associated operation & maintenance (O&M) costs.

87. Additional safety considerations from the coupling of a nuclear power plant with an industrial process plant also need to be addressed. These include tritium permeation issues in the steam, and safety distances between a nuclear reactor and an industrial plant containing potentially flammable material (hydrogen).

88. The complexity of integrating cogeneration applications to the operation of a nuclear power plant also brings additional costs [Taylor, 2009]. Examples of this complexity include:
• The mismatch between the operation of the nuclear power plant (annual schedule of 11 months of continuous operation with 1 month of outage for maintenance & refuelling) and that of the process applications which:
  o Either have varying demand curves (district heating, winter/summer, daily variations)
  o Or demand constant steam supply (industrial processes), and therefore, require a steam production backup when the reactor is in outage. This backup can either be a 2nd nuclear unit or a fossil-fired unit.

• The mismatch between reactor and process lifetimes. Reactors typically operate for 40 to 60 years, whereas process application plants typically have a 25 year lifetime.

• The optimal share between electricity production and process steam supply may be difficult to determine. As pointed out in [Madlener, 2012], a utility may want to be able to switch easily from producing electricity and heat to producing electricity only, and this may have consequences on the design of the nuclear power plant.

4. Methodologies, economic studies and business models

4.1 Methodologies

89. Different methodologies exist to analyse the economics of cogeneration, be it from nuclear energy or other types of fuel.

90. The power or heat credit method, used by the IAEA for instance to evaluate the economics of nuclear desalination [Taylor, 2009]. The same method was applied to the economic assessment of small reactors [NEA, 2011], 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.

91. Another approach is based on the exergy analysis [Szargut, 2005, Rosen, 2001, 2009b]. The method states that “a purely economical principle of cost partitioning in the cogeneration process exists, namely the principle of avoided expenditures. The production cost of a useful by-product should be evaluated according to the production costs that can be avoided in the overall system” [Szargut, 2005] (p. 32). Rosen also comments that “cogeneration systems which produce heat at useful temperatures at the expense of reduced electrical output, can have greater efficiencies than conventional electrical generating stations but the merit of cogeneration must be determined using exergy analysis because energy analyses tend to overstate performance” [Rosen, 2001].

92. In order to assess the business case of making a nuclear power plant investment, the Real Option Analysis (ROA) method was used by Madlener [Madlener, 2012] and Halbe [Halbe, 2008] instead of the more traditional Net Present Value (NPV) approach. The authors claim that the ROA method 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. Both applied the method to high temperature reactor cogeneration (see section 4.3).

93. Finally, the target cost methodology applied by Shropshire for electricity-generating SMRs [Shropshire, 2011], was recently extended to include cogeneration application for the same class of reactors [Carlsson, 2012]. The method assumes a heat credit based on the cost from an alternative technology, for example a gas-fired boiler.
4.2 Economic studies

94. Many economic studies of nuclear cogeneration have been published (for instance [Rosen, 2001, 2009a], [Kuhr, 2006]), and it is proposed to review the assumptions, methodologies and conclusions of these studies. Other studies of interest include:

- The study of the economic viability of HTR cogeneration vs. gas cogeneration. As can be expected, there is extreme sensitivity to the price of gas. The volatility of gas prices induces large uncertainties on the viability of cogeneration from nuclear reactors. [Bredimas, 2011b]
- Studies on nuclear desalination [IAEA, 2007], [Nisan, 2007]. The IAEA has developed a computer code called “DEEP” (Desalination Economic Evaluation Program) to perform economic modelling.
- Studies on the economics of nuclear hydrogen production: Gomez et al., who used the exergy loss concept [Gomez, 2007, 2008], Miller et al. [Miller, 2005], or Rivera-Tinoco et al. [Rivera-Tinoco, 2007]. The latter study looks at hydrogen production with High Temperature Electrolysis using different reactor technologies (PWR, SFR, HTR). The electricity cost assumptions for these were 33€/MWh for an EPR reactor (PWR), 22.7€/MWh for a BN-1800 (SFR) and 40€/MWh for an HTR, values which are significantly below typical generation costs given in [NEA, 2010b].
- The study of Forsberg [Forsberg, 2006] on peak vs. base load electricity and hydrogen production issues identifies the cost factors in the development of the nuclear hybrid energy systems.
- Two studies related to nuclear district heating can be mentioned. One, 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 100km from Helsinki (no reference available). The other study, currently on-going, is performed by France’s CEA [Safa, 2011, 2012] and concerns a feasibility study for transporting heat from Nogent sur Seine nuclear power plant to the Paris district heating network, situated some 130km away.
- The extraction of bitumen from oil sands and its upgrade to synthetic fuel using steal and hydrogen produced by a nuclear reactor was analysed by Bersak et al. [Bersak, 2007]
- The study by Carlsson et al. [Carlsson, 2012] focuses on the possible role of SMRs in future European cogeneration market, using target costs derived from competing technology. The authors claim that besides the potential advantages that SMRs have over larger units in electricity markets with intermittent and distributed power generation, such reactors could also target different segments of the cogeneration markets. The study finds for example that for a SMR-based cogeneration plant to be competitive against coal or gas, its overnight capital costs would need to be in the range 5000-7500 €/kWe.

4.3 Business models for nuclear cogeneration

95. One of the difficulties of nuclear cogeneration is that of the associated business models. End-users of process heat are not interested in the operation of a nuclear power plant. It is not their core business, and they do not wish to shoulder the nuclear liabilities that come with the responsibility of the operator. Thus, operators of nuclear cogeneration plants are more likely to be found amongst organisations that have the experience of nuclear plant licensing and operational requirements, i.e. nuclear utilities. The owner of the nuclear power would then have long term purchase agreements to supply heat and electricity to one or more industrial facilities. Excess electricity can then be sold on the market, which is the usual business of utilities.
96. A separate study on business models and economics of nuclear cogeneration from a “utility’s perspective” was performed by Madlener (RWTH Aachen University) and reported in [Madlener, 2012] on the basis of the European heat market. The study, using the ROA method, shows that despite positive NPV and an internal rate of return (IRR) above the costs of capital, a utility would be advised not to carry out the investment of building a HTR for cogeneration. There is too much uncertainty in the technology itself (until a FOAK has been built) which leads to uncertainties in the NPV and IRR themselves, and the investment should be delayed until electricity prices reach above a certain threshold. The study also emphasises the importance for the utility of being able to switch from supplying heat to supplying electricity only, which has implications on the design of the reactor.

97. An earlier study [Halbe, 2008] examined the economic basis of an investment into a VHTR (Very High Temperature Reactor, which is a Generation IV technology under development and has a greater potential for producing hydrogen than HTRs) in the Netherlands using the same ROA methodology. The NPV approach gives a negative value for the construction of a VHTR, but, taking into account the flexibility to switch from electricity generation to hydrogen production, the ROA approach shows that the investment can be justified, depending on the hydrogen price scenario.

5. Nuclear hybrid energy systems – prospects for coupled fuel and electricity production

98. Over the last decade, several concepts of nuclear hybrid energy systems have been proposed, involving the coupling of electricity with fuel production (hydrogen, synthetic fuel from coal gasification, etc) using nuclear heat [Forsberg, 2006, 2012] [NREL, 2011, 2012]. A particular concept proposed by Forsberg involves the synergy between nuclear power plants, intermittent renewable sources (wind or solar) and hydrogen production, storage and use in fuel cells, as sketched in Figure 4. The concept allows nuclear power plant to run at their optimal rate, which is base load, with the hydrogen system acting as an energy buffer to cope with the variations of renewable power production and electricity demand.

99. According to Forsberg [Forsberg, 2012], the nuclear power plant would run continuously near its peak output. When the demand for nuclear electricity is low (because of high renewable production or when the overall electricity demand is low), hydrogen would be produced using electrolysis (the reverse principle of a fuel cell), and then stored. When there is a peak demand for electricity, instead of resorting to gas turbines, the system would produce electricity from the fuel cell. The capital cost savings made by not buying gas turbines pays for the electrolysis/fuel cell system.

100. The critical issues in such a concept are [Forsberg, 2006]:
- The bulk storage of hydrogen (only low cost bulk storage of hydrogen in underground salt deposits exists as a commercial technology)
- The absence of a “hydrogen transmission” system.

101. As mentioned earlier, Europe has the largest H2 pipeline network in the world, so this concept, developed in the United States, could be of interest to Europe, where ambitious policies to deploy renewable technologies are in place and where grid stabilisation needs are becoming important.

**Figure 4. Nuclear/Renewable/Hydrogen system proposed by Forsberg (from M. Ruth’s presentation at Hybrid Energy Systems Workshop, Salt Lake City, April 2012 [NREL, 2012])**

6. Contribution of nuclear cogeneration to the reduction of GHG emissions

102. One major contribution that nuclear cogeneration could bring to the world’s energy systems is that of decarbonising the non-power sector. The power sector only represents 41% of the world’s emissions (Figure 5). There are other sectors where nuclear cogeneration could help reduce CO₂ emissions significantly.

**Figure 5. World CO₂ emissions in 2009 [IEA, 2011b]**
103. Nuclear district heating could reduce emissions from the domestic heat sector; Production of hydrogen and other synthetic fuel could lower the carbon footprint of the transport sector; Process heat delivered to industry could reduce the need for fossil-fired steam production. In the future, as fresh water resources become scarce, an increasing number of countries will have resort to seawater desalination to produce fresh water for their needs. Unless powered by low carbon energy such as nuclear or renewable technologies, use of desalination will lead to increased carbon emissions.

104. One of the objectives of the proposed study could be to analyse on a sectorial basis the potential contribution to the reduction of greenhouse gas emissions that could be achieved through the displacement of fossil-based processes by non-electric applications of nuclear energy.

7. **Scope and objectives of the proposed study**

105. In conclusion, an overview of the current status of nuclear cogeneration has been given in this background paper, which provides the scope of the proposed study. A number of issues have been highlighted (in red in this paper). Given the recent work performed by the NEA in the area of:

- Projected costs of electricity generation (2010).
- System costs (2012).
- Role of nuclear energy in a low carbon energy future (2012).

106. The following questions relating to nuclear cogeneration should be answered:

- What is the appropriate methodology to analyse the economics of cogeneration?
- What are the cost drivers that need to be taken into account in the study of a nuclear cogeneration system?
- In a so-called “nuclear hybrid system” as described in section 5, what are the other cost drivers and economic benefits of operating a nuclear cogeneration system in synergy with other electric or industrial systems?
- What are the most promising cogeneration markets, the most appropriate nuclear reactor technology for each application, and realistic “time to market” estimations?
- What is the potential contribution of non-electric applications of nuclear energy to the overall reduction of greenhouse gas emissions from the energy sector?

**Proposal to the NDC:**

Prior to launching a full project, perform an exploratory study with a consultant (about 6 month) to figure out whether there is a potential field for the NEA, and whether a generic economic methodology can be envisaged. The NDD will report to the NDC on the results of the exploratory study in the middle of 2013.
References


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