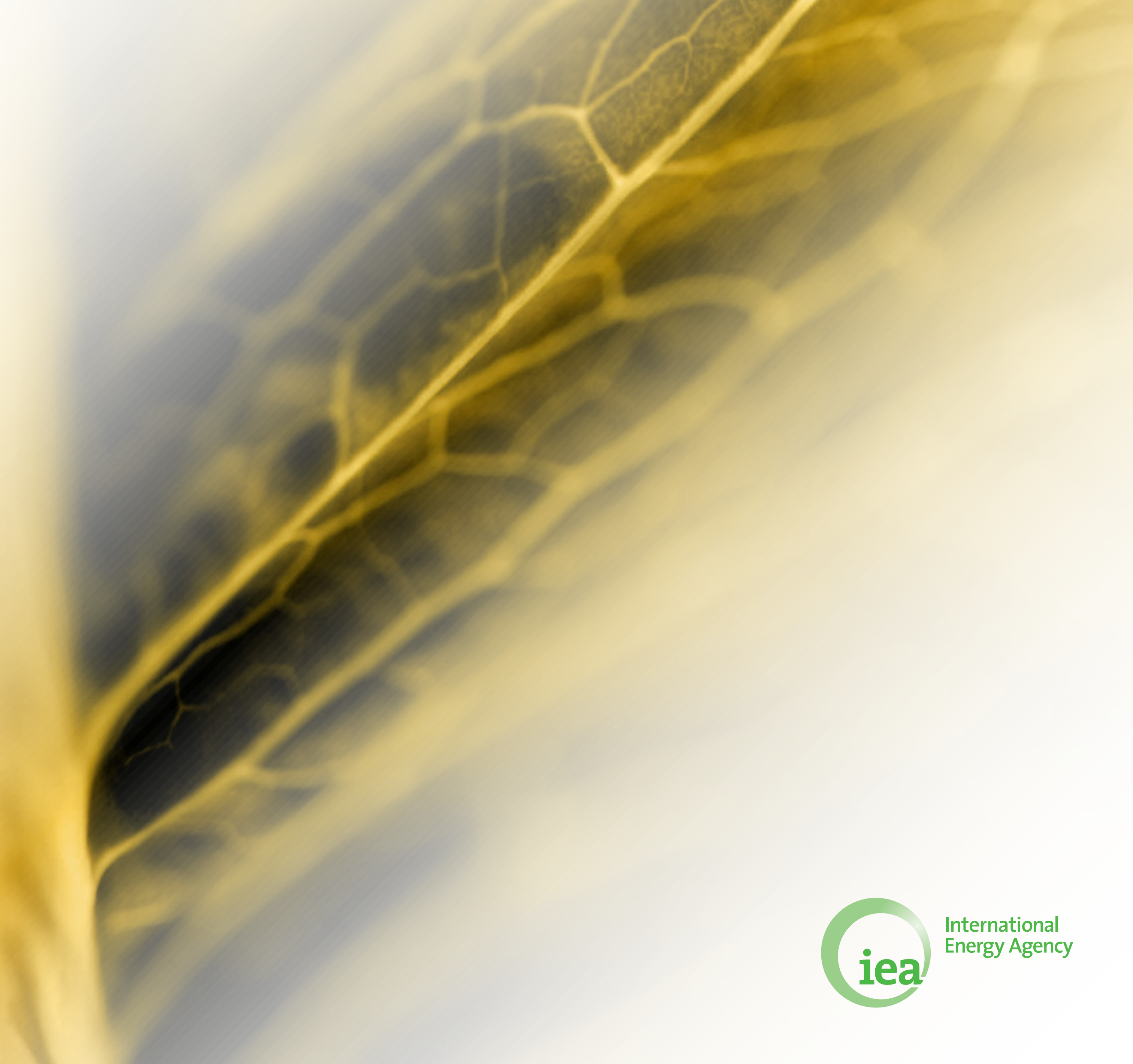
Linking Heat and Electricity Systems

Co-generation and District Heating and Cooling Solutions for a Clean Energy Future



International Energy Agency

Linking Heat and Electricity Systems

Co-generation and District Heating and Cooling Solutions for a Clean Energy Future

International Energy Agency

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea (Republic of)
Luxembourg
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Turkey
United Kingdom
United States

The European Commission also participates in the work of the IEA.

International Energy Agency
1974•2014
Secure • Sustainable • Together

International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15, France

www.iea.org

Table of contents

List of figures

List of tables

List of boxes

Foreword

Our energy systems are becoming increasingly complex, underpinning the need for efficient and flexible technologies and networks. At the same time, the realities of climate change mean that sustainable solutions must be implemented in the near term to avoid long-term environmental consequences. In order to meet these challenges and maximise the impact of our efforts, we must consider the sustainability of the energy system as a whole.

Co-generation and efficient district heating and cooling (DHC) can support an integrated energy system by providing a flexible link between electricity and thermal energy while delivering enhanced energy efficiency. These technologies are ready for implementation today, yet global progress in deployment has been slow. Recently, some countries have recognised the contribution that these technologies can make to a sustainable energy future by setting up deployment programmes.

This report builds on a compendium of case studies of successful co-generation and DHC projects to analyse the impact of existing barriers and opportunities to the deployment of co-generation and efficient DHC. The analysis highlights the need to create a long-term stable market environment that incentivises energy efficiency as a critical factor for the uptake of these technologies, as well as strategic planning for energy infrastructure to optimise the use of local energy sources.

As we move forward, efficient and flexible technologies will become increasingly important, and policy makers and project developers should learn from the experiences of others in order to fully realise the potential of co-generation and DHC. By building upon past successes, we can use lessons learned to help create a better integrated energy system in the future. The IEA hopes that this report can serve as a guide for policy makers developing sustainable energy policy strategies.

This publication is produced under my authority as Executive Director of the IEA.

Maria van der Hoeven
Executive Director
International Energy Agency (IEA)

Acknowledgements

This report was prepared by Araceli Fernandez Pales, John Dulac, Kira West and Marc LaFrance of the IEA. The authors would like to thank the following people and organisations who provided case study information, comments and expertise: Javier Rodríguez Morales (Acogen), Ennis Rimawi (Catalyst Private Equity), Javier Dintén Fernández and Jaime Igea López-Fando (Cogen Energía España), Ana Delia Córdova Pérez and Jorge Armando Gutiérrez Vera (Cogenera Mexico), Claire Wych and Jonathan Graham (CHPA), Marco Gangichiodo and Antonio Dicecca (Climespace GDF Suez), Krzyzstof Laskowski (Euroheat&Power), Niko Wirgentius (Fortum), Angelika Cerny, Tamara Khoury and Meera Drabkah (Millennium Energy Industries), Per Alex Sorensen (PlanEnergi Nordjylland), Jorge Javier Mañon Castro and Carlos Azamar (Pemex), Tomas Jumar (RWE Innogy) and Stephan Renz (Swiss Federal Office of Energy). The Finnish Ministry of Employment and the Economy, VTT Technology Research Center of Finland, IEA Committee on Energy Research and Technology and IEA Working Party on Energy End-Use Technologies, as well as other members of the IEA CHP and DHC Collaborative provided support for this project. Thanks are also due to IEA colleagues such as Jean-François Gagné, Didier Houssin, Cecilia Tam, and Christelle Verstraeten who provided thoughtful comments. Finally the authors would like to thank Jonas Weisel for editing the manuscript, as well as the IEA publication unit, in particular Muriel Custodio, Cheryl Haines, Astrid Dumond, Bertrand Sadin and Hanneke van Kleeff for their assistance on graphics, editing and layout.

Executive Summary

Co-generation[1] technologies and efficient district heating and cooling (DHC) networks provide clear environmental benefits due to their enhanced conversion of energy and use of waste heat and renewable energy sources. Co-generation and DHC can also serve as flexible tools to bridge electrical and thermal energy systems, which will play an increasingly important role in achieving integrated, sustainable energy networks in the future. These technologies can therefore be an essential part of strategies for greenhouse gas (GHG) emissions mitigation and energy security.

While these technologies represent a considerable share of the energy generation portfolio in some countries, global deployment of co-generation and efficient DHC has been much less successful - global electricity generation from co-generation was reduced from 14% in 1990 to around 10% in 2000, and it has remained relatively stagnant since then. Significant barriers prevent extensive penetration and modernisation of these technologies. These barriers are mostly related to poor strategic planning for heating and cooling infrastructure, local energy market conditions failing to ensure energy prices that are reflective of generation costs, and lack of long-term visibility of related energy policies.

However, despite the lack of progress globally, some countries and regions have recently shown a renewed interest in co-generation and efficient DHC networks. This interest includes the 2012 European Energy Efficiency Directive calling for an assessment of the potential additional deployment of these technologies (EU, 2012), a 2012 US Executive Order aiming to achieve 40 gigawatts (GW) of industrial co-generation by 2020 (US, 2012), the strong indication that People's Republic of China will reach 50 GW of gas-driven distributed co-generation by 2020 (NDRC et al., 2011) and the creation, in 2012, of a co-generation roadmap in Japan targeting a five-fold increase in co-generation-based electricity by 2030 (EEC, 2012). Although these directives and targets recognise the potential of these technologies, significant efforts have yet to be made to realise all their benefits for a sustainable energy future.

Applied solutions and lessons learned

The report builds on real case studies from a selected range of applications, technologies and locations to analyse the impact of existing barriers and opportunities. This includes a detailed assessment of the different phases of the development of co-generation and efficient DHC projects, from conception to operation. The case studies analysed in this report include three industrial co-generation applications and three DHC systems:

- The Eresma Cogen project consists of a gas engine-based 13 megawatts electric (MWe) **co-generation system** that supplies electricity and heat to a **distillery factory** in Segovia, **Spain**. The generation system provides 70% of process steam and all the electricity requirements of the industrial site, and it exports the excess electricity to the grid, saving roughly 16 kilotonnes (kt) of carbon dioxide (CO_2) every year.
- The **co-generation plant** located in the **gas processing** complex of Nuevo Pemex in Tabasco, **Mexico** provides heat and power for on-site requirements and exports electricity to other users. The generation system has a 300 MWe installed capacity and includes two natural gas turbo

[1] Co-generation is also commonly referred to as combined heat and power (CHP). This report uses the term "co-generation" to refer to the simultaneous generation of heat and electricity.

generators with heat recovery equipment that result in 430 kt CO2 per year savings compared to conventional generation technologies.

- The **Markinch biomass p**roject consists **of a 60 MWe co-generation plant** at the Tullis Russ**el paper mill** in Fife, **Scotland**. The generation unit provides heat and electricity to support the paper production process, and it exports excess electricity to the grid. It is estimated that the plant will avoid 250 kt CO_2 per year.
- The Sunstore 4 project is a district heating plant located in Marstal, **Denmark** that was developed to demonstrate the production of **100% renewable-based district heating** and flexible management of different intermittent energy sources with the assistance of thermal storage. The plant combines solar thermal, a biomass boiler coupled with an Organic Rankine Cycle (ORC), a heat pump and thermal storage. It is estimated to save 10.5 kt CO_2 annually.
- The Bercy cooling plant is a **district cooling** facility in Paris, **France** with a current capacity of 44 megawatts (MWth). Free cooling assistance has been applied to this system resulting in a 34% increase of the average coefficient of performance (COP) of the plant's chillers. Overall, the plant is estimated to save 7.4 kt CO_2 annually.
- The **solar thermal district heating system** installed in the Princess Noura Bint Adbul Al Rahman University for Women (PNUW) in Ridyadh, **Saudi Arabia** is the world's biggest operating solar heating project with 36 610 m^2 of rooftop flat-plate collectors. The system provides space heating and hot water to the university students and saves 5 kt CO_2 per year.

These real-world examples were used to inform the analysis of barriers impeding increased penetration of co-generation and efficient DHC in markets across the world, as well as to demonstrate the applied value of these technologies to achieve sustainable, efficient energy systems. Long-term stability of a policy strategy rewarding energy efficiency was demonstrated by the case studies to be the most important lever to unlock deployment of co-generation by limiting associated investment risk. The analysis of these real applications also showed that innovative and highly integrated DHC systems pose technological challenges, which can be solved through the co-operative effort of experience sharing and, in some cases, financial support to demonstrate pioneer systems.

Key policy recommendations

The report provides a set of policy measures and recommendations to overcome market and policy barriers from an energy systems integration approach.

Policy strategies to support the cost-effective selection of co-generation and efficient DHC technologies

- Ensure that market conditions promote transparent and fair fuel prices and reflect the real cost of electricity and heat generation to promote efficient use of energy.
- Consider co-benefits of promoting the most efficient use of low-carbon and renewable energy sources through effective co-ordination and complementarity of energy efficiency and renewable energy policies.
- Ensure streamlined and clear grid interconnection standards to facilitate exploiting the flexibility potential of co-generation technologies.
- Develop strategic local, regional and national heating and cooling planning based on mapping of demand and source points to identify cost-effective opportunities for co-generation development, and refurbishment or expansion of co-generation capacity and DHC networks.

Policy strategies to reinforce the economic feasibility of co-generation and DHC projects

- Ensure long-term stability of energy policies and market regulation to secure investments in efficient electricity and heat generation and distribution technologies.
- Consider financial and fiscal incentives that mitigate the impact of markets failing to reflect fair energy prices and that take into account the environmental benefits of efficient generation technologies.
- Facilitate investment in modernisation and improvement of the operation of existing inefficient DHC networks through financial incentives.

Policy strategies to support the optimisation of co-generation and efficient DHC networks in integrated sustainable energy systems

- Support research activities to design sustainable business models that reward flexibility, low-carbon energy sources and energy efficiency in complex and highly interconnected energy systems. Promote their implementation and share lessons learned from those experiences.
- Co-ordinate the development of local, regional and national strategic infrastructure deployment plans with developers of smart business models for energy networks. Define joint measures to minimise costs, capture energy-saving opportunities and support the prioritisation of energy efficiency measures.

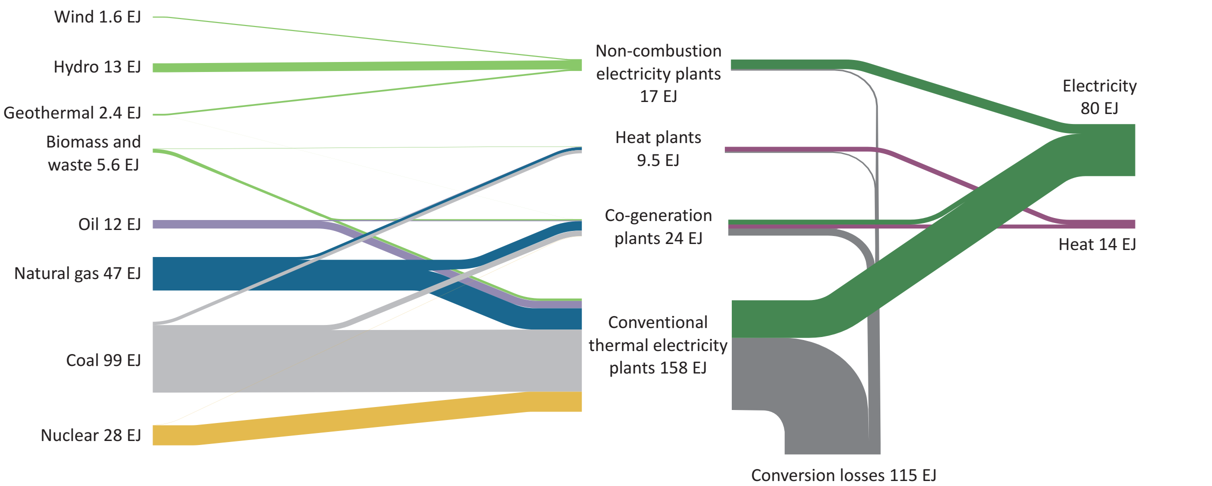
Introduction

Co-generation and DHC can play a fundamental role in a low-carbon economy, yet their potential remains an untapped resource that has not been effectively pursued within energy policy and technology initiatives. Large quantities of heat are currently wasted in power stations and heavy industry. In end-use sectors, such as residential and commercial buildings, heating and cooling needs could be met through better optimisation of the energy supply-and-demand matrix. Co-generation and DHC could play a much more important part in achieving this optimisation through technology solutions for a more efficient, integrated energy system.

Co-generation technologies enable the simultaneous generation of heat and electricity, increasing the overall energy efficiency of the conversion process in comparison with conventional thermal generation technologies. This efficiency is achieved by partially recovering heat produced during electricity generation to make it available for end-use applications.

Globally, thermal power plants achieved a conversion efficiency of 36% in 2011 (IEA, 2013b). By contrast, co-generation units converted about 58%[2] of energy input into electricity and heat in the same year (Figure 1) (IEA, 2013b). State-of-the-art co-generation units can reach conversion efficiencies of as much as 90% (IEA, 2013b).

Figure 1 • Global power and heat generation energy flows, 2011



Notes: following IEA energy balance conventions, for auto-producer co-generation plants, only heat generation and fuel input for heat sold are considered, whereas the fuel input for heat used within the auto-producer´s establishment is not included but is accounted for in the final energy demand in the appropriate consuming sector. Totals may not equal the sum of their components due to rounding. Transmission and distribution losses are not included.

Source: unless otherwise noted, all tables and figures in this report derive from IEA data and analysis.

Key point • Only about 36% of the energy going to thermal power plants is converted into electricity in comparison to a 58% average conversion on co-generation sites.

[2] Following IEA energy balance conventions, for auto-producer co-generation plants, only heat generation and fuel input for heat sold are considered, whereas the fuel input for heat used within the auto-producer's establishment is not included but is accounted for in the final energy demand in the appropriate consuming sector.

Efficient DHC networks provide the required infrastructure to distribute recovered heat from co-generation sites to end users. These networks can benefit from locally available, carbon-free[3] energy sources, such as solar thermal heat and waste heat recovered from industrial processes that can be injected into a district heating network or converted into cooling capacity using absorption chillers. Natural cooling sources, such as water from lakes, seas and rivers, can also be used.[4] DHC networks based on these carbon-free and natural energy sources could achieve energy efficiencies five to ten times higher than traditional electricity-driven equipment (DHC+ Technology Platform, 2012).

Due to their flexibility and enhanced efficiency, co-generation and DHC can play a relevant role in an integrated energy system by providing a sustainable option to help balance a greater share of variable renewable energy sources. In addition to their turndown range and capability,[5] co-generation technologies can operate within a range of power-to-heat output ratios, allowing units to adapt to specific energy demand requirements over time. The addition of energy storage capacity to co-generation plants can also provide an added level of flexibility to regulate electricity and heat outputs while minimising energy losses. These technologies can use a wide range of energy sources, from fossil fuels to waste and renewable sources, such as biomass, solar and geothermal energy.

DHC networks can similarly be designed and operated as energy-balancing tools. By incorporating other technologies, such as heat pumps and thermal storage capacity, DHC networks can absorb excess electricity generation when needed by the system. DHC networks can also help to mitigate peak demand electricity loads by providing alternative heating and cooling supply options.

Despite these benefits, co-generation technologies and high-efficiency DHC systems are still not extensively deployed. Only 9% of global electricity generation uses co-generation technologies (Figure 1) (IEA, 2013b), and penetration has remained stagnant over the last decade. While some countries have achieved a high share of co-generation in electricity production (for instance, Denmark has more than 60% and Finland almost 40%), most countries have not been that successful.

Experience from countries with high levels of co-generation and efficient DHC production illustrates that strategic decisions to consider co-generation and DHC as key energy security and climate solutions are critical to achieving increased penetration. In these countries, deployment did not necessarily require substantial financial incentives. Rather, targeted policies were crucial to effectively addressing barriers to further deployment of co-generation and DHC technologies.

Existing barriers to co-generation and efficient DHC network deployment can be grouped by specific phase of project development, including project conception and technology selection, project financing and economic feasibility, and business structure.

Barriers preventing the selection of co-generation and efficient DHC technologies include:

- Market conditions and energy prices failing to reward energy efficiency.
- Energy policies not fairly rewarding the use of industrial waste heat or natural cooling sources in comparison to renewable energy sources.
- Non-transparent, inconsistent interconnection procedures and back-up charges.

[3] Industrial waste or surplus heat refers to heat contained in side-streams, product or waste-streams produced as part of the normal operation of industrial processes; this heat, unless recovered, would be released to the environment, and thus the use of recovered surplus heat is considered carbon-free.

[4] The use of natural cooling sources will need to comply with local environmental regulation and required impact assessments.

[5] Turndown range refers to the ratio between maximum and minimum operating loads of a plant, while turndown capability defines the rate at which the operating load can be decreased. Both terms provide an indication of the degree of flexibility of a generation unit.

- Lack of knowledge in society about co-generation benefits and savings.
- Lack of integrated heating/cooling supply planning.

Barriers reducing economic feasibility of co-generation and DHC include:

- Higher upfront investments compared to conventional generation and distribution systems.
- Economic and market issues related to difficulties in securing fair value prices for electricity from co-generation exported to the grid.
- Uncertain energy policies lacking long-term visibility.

Barriers reducing flexibility of the business structure of complex energy systems include:

- Lack of energy efficiency policy co-ordination on supply, distribution and end use.
- Lack of business models that reward energy flexibility and sustainability.

This report provides practical examples and approaches to how these barriers can be overcome to achieve increased penetration of co-generation and DHC technologies in support of an efficient, integrated, low-carbon economy. The following sections describe specific co-generation and modern DHC solutions and analyse them from different angles, including the technology selection made, business structure developed and financing mechanisms used. The report also considers the role played by the regulatory framework within which projects have been implemented.

In addition, the report presents six specific co-generation and DHC projects, including three industrial co-generation case studies and three high-efficiency renewable DHC case studies. These case studies offer practical examples to distil real-life solutions of technology choices, financial tools and market structures, including lessons learned and possible application in other contexts.

Co-generation and DHC Solutions Analysis

Co-generation represents a series of proven technologies, covering a wide range of end-use applications, capacity ranges, fuel bases and technology uses. The majority of these technologies can be grouped into three categories: industrial processes, DHC, and small commercial and residential applications. This report focusses on industrial and DHC[6] applications.

Co-generation units installed in industrial processes

Energy-intensive industrial sectors such as chemicals, refining, pulp and paper, and food and beverage typically have high process-heat requirements and considerable electricity needs. Co-generation technologies are capable of providing heat up to 400 degrees Celsius (°C). Almost all process-heat demand in the food sector is below 400°C, as well as approximately 51% and 83% of the total heat demand of the chemicals and pulp and paper sectors, respectively. Taking these characteristics into account globally, the estimated maximum theoretical technical potential for heat co-generation represents 4.8 exajoules (EJ) and 3.3 EJ in the chemicals and pulp and paper industrial sectors, respectively, based on 2011 energy use data (IEA analysis based on Ecoheatcool, 2006). However, the cost-effective potential of these applications is highly dependent on local energy prices and regulatory conditions. Data availability limitations on existing global industrial co-generation capacity make it difficult to estimate the share of additional capacity potential within the indicated maximum theoretical level.

Some industrial processes also generate waste streams that are suitable for use as co-generation fuels that can reduce a site's operating costs by reducing fuel expenditures. Personnel at these industrial facilities are often qualified to operate the necessary co-generation units, providing a suitable environment for co-generation technologies to be applied. In 2011, industrial co-generation facilities generated 26% of total global electricity generation from co-generation (37% and 15% in Organisation for Economic Co-operation and Development [OECD] member countries and non-member economies, respectively).

Co-generation applications connected to DHC networks

District heating (DH) networks supply heat for low- and medium-temperature applications, such as space heating and hot water in residential and commercial buildings. District cooling (DC) can similarly be produced from heat via absorption chillers and from natural cooling sources such as rivers and the ocean. Heat supply applications for both DH and DC can include heat recovered from co-generation units, industrial processes and other generating sources, including renewable energy. The potential for these applications depends on the characteristics of the thermal load (temperature and regularity) as well as on electricity prices and population density, which directly affects required capital infrastructure investments and the associated payback period.

In 2011, 79% of total DH in OECD countries was produced by co-generation plants (IEA, 2013). In Europe, roughly 12% of total heat demand was met by over 6 000 DH systems, whereas DH sales in China (2.81 EJ) (Euroheat&Power, 2013) represented about 23%[7] of residential and commercial heating demand. This level of demand represents a growth of 25% between 2007 and 2011 in DH sales in China (Euroheat&Power, 2013).

[6] The section on co-generation applications connected to DHC networks can also include stand-alone district energy networks.
[7] Based on IEA ETP Buildings model data for residential/commercial heating demand.

Current DC sales are still limited compared to global cooling demand. The greatest DC sales are in the United States, accounting for 24.71 terawatt hours (TWh) (Euroheat&Power, 2013), although this amount still represents only 6% of the country's space cooling demand in residential and commercial buildings.[8] Significant potential exists for DC growth. The capacity of DC through chilled water in Korea alone more than tripled between 2009 and 2011 (Euroheat&Power, 2013), and as global space cooling demand continues to increase – more than doubling by 2050[9] – DC solutions will have an important role in providing efficient, low-carbon cooling supply.

Challenges and solutions: analysis of real-life examples

Often, co-generation projects look attractive when analysed independently from market and regulatory conditions. In practice, implementation of co-generation technologies has been challenging, as proven by current limited co-generation penetration in the global energy market: only 9% of total electricity generation comes from co-generation plants. DHC projects similarly may be attractive from an energy-saving perspective, but often they require both more investment in infrastructure than is financially viable in the current economic climate, and an established long-term urban planning strategy, which is sometimes lacking. Little progress in practical implementation of efficient DHC networks has been achieved in recent years.

To assist policy makers in addressing barriers to implementation of successful co-generation and DHC solutions, this report has developed a compendium of case studies, including industrial co-generation and DHC applications, as the basis for the report's analysis. These case studies address diverse applications, locations, capacities, energy sources and achieved CO_2 savings (Table 1).

Table 1 • Co-generation and DHC case studies analysed

Project name	Type of application	Location	Capacity (MW)	Energy input	CO_2 savings compared to conventional generation technologies (kt/year)
Markinch project	Industrial co-generation: Paper sector	United Kingdom	127	Biomass	250
Eresma project	Industrial co-generation - Beverage sector	Spain	23	Gas	16
Nuevo Pemex project	Industrial co-generation: Gas processing and Refining sector	Mexico	730	Gas	430
Marstal project	Biomass co-generation and solar thermal DH with storage and heat pump	Denmark	6	100% renewable	11 *
Bercy project	DC network assisted with natural cooling	France	44	Natural cooling assisted	7 **
PNUW project	DH network with solar thermal and storage	Saudi Arabia	25	Solar, diesel (aux. boilers)	5

Note: CO_2 = carbon dioxide; kt = kilotonnes; MW = megawatts.
* Assumed savings (see case study for details).
** Includes CO_2 emissions from refrigerant releases. Not considering refrigerant-related emissions, CO_2 emissions savings for this project are 5.5 kt/year.

Sources: RWE Innogy representatives (2013), Personal communication; Cogen Energía España representatives (2013), Personal communication; Pemex representatives (2013), Personal communication; PlanEnergi Nordjylland representatives (2013), Personal communication; Climespace GDF Suez representatives (2013), Personal communication; Millennium Energy Industries representatives (2013), Personal communication.

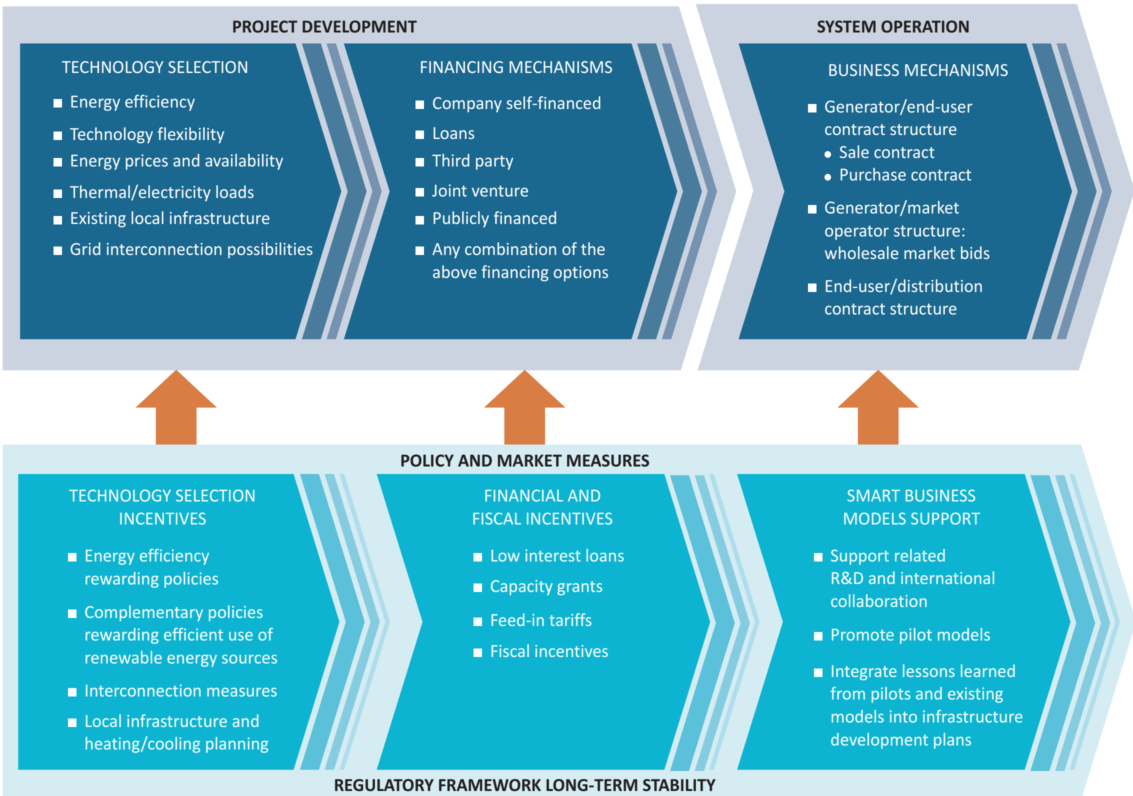
[8] Based on IEA ETP buildings model data for residential/commercial space cooling demand.
[9] Based on IEA ETP buildings model data for residential/commercial space cooling demand.

The studies examine in greater detail the technology choices, business structures, regulatory contexts, and specific barriers and challenges that are encountered during project development and implementation. The case studies also demonstrate how these challenges can be overcome. Their conclusions informed the report's analysis of common obstacles to deployment of co-generation and efficient DHC, and subsequent analysis aims to provide insight for policymakers and stakeholders in moving towards a more efficient, low-carbon energy system using these technologies.

The project development phase examined in the case studies is divided into two sections: one, an analysis of technology selection and the other, a look into the financing mechanisms used in the projects. The case studies analyse subsequent system operation in terms of the business structure to understand how interactions between energy users and producers can help drive energy savings in the overall system. Each case study also assesses market and regulatory conditions and draws conclusions and lessons learned.

Several factors can affect the decisions made at each of the project development phases or the definition of the system´s business structure (Figure 2). The project's success can be influenced by a good understanding of the environmental and flexibility benefits of co-generation technologies and modern DHC networks, as well as the existence of appropriate policy measures and fair market conditions rewarding these benefits.

Figure 2 • Key factors in development and operation of co-generation and DHC projects



Key point • Many factors determine the success of co-generation and DHC projects. The most important factor to facilitate long-term investments is a stable and effective regulatory framework.

Technology selection justification

Several factors determine which technologies and configurations are suitable for co-generation applications, including quantity and quality of heat and electricity demand loads, the pattern of the consequent power-to-heat ratios over time, and end-user location. Economic and environmental aspects, such as energy efficiency, local fuel prices and availabilities, and existing local distribution infrastructures and the ability to interconnect to them also affect the relative competitiveness of co-generation technologies and DHC networks in comparison to other conventional technologies and technical approaches.

- **End-use energy efficiency comes first**. Energy demand profiles directly influence generation and distribution system capacities. Implementation of energy efficiency improvements and demand-side management measures on end-use applications should be considered prior to defining potential supply system solutions, to ensure that the resulting heat and electricity needs are minimised when possible. This approach avoids excessive capacity on generation equipment, which can affect production energy efficiency performance if the system is not operating at its optimal load level.
- **Temperature counts**. Industrial processes are very diverse, and their heat demand ranges from ambient temperatures (25°C) to temperatures above 1 500°C. Heating needs from processes operating at temperatures below 400°C can technically be supplied by co-generation technologies. In those industrial processes that generate exhaust and waste streams at high temperature levels, steam can be generated by partially recovering the heat that otherwise would be released to the environment. This steam can be used to meet on-site heat demands or integrated in local DHC networks if temperature compatibility is favourable. In the case of steam temperatures above 430°C, electricity may still be generated through steam turbines if thermal demand is not locally available or favourable (EPA, 2008).

  Existing DH networks typically operate at supply and return temperatures in the range of 110°C to 80°C and 60°C to 50°C, respectively. Newer DHC systems can operate at lower temperatures of 90°C (supply) and 40°C (return), and research is also under way through the IEA Implementing Agreement on District Heating and Cooling to develop next-generation DH systems that operate at temperature ranges of 55°C to 50°C (supply) and 30°C to 25°C (return) (Wiltshire, 2013).

  Reducing supply and return temperatures is a critical first step to improving DHC network efficiency (in addition to addressing demand and building energy efficiency), because it has a positive impact on energy savings by decreasing required heating energy input, thermal energy distribution losses and network pumping requirements. Beyond these savings, additional energy reduction can be achieved through the direct use of low-temperature industrial surplus heat and co-generation applications that have lower net energy input to provide DH needs. For instance, the ORC is an example of applying low-temperature energy sources such as waste heat, geothermal, solar thermal and biomass, by using an organic fluid in the heat generation cycle instead of water, enabling the system to operate at a lower boiling point.
- **Get the right heat-to-electricity ratio**. For co-generation technologies to be a cost-competitive option in comparison to conventional separate production of heat and electricity, simultaneous demand needs to exist for both electricity and heat. Under these conditions, co-generation options can pay back the additional investment requirement associated with greater technical complexity of equipment through energy savings generated by a higher overall energy efficiency level subject to existing local energy prices. Generally, the capacity of a co-generation system is set to meet the required thermal load, because this is usually the limiting factor; however, optimum design needs to be assessed on a case-by-case basis. From an operational perspective, a

co-generation unit should aim to maximise the exergy[10] output (heat and electricity) within local constraints, thus optimising the system's environmental benefits. The heat-to-electricity ratio determines the most suitable co-generation prime mover. Typical heat-to-power ratio ranges are 0.5 to 1.5 for internal combustion engines, 1 to 10 for gas turbines and 3 to 20 for steam turbines (Cuttica and Haefke, 2009).

Finding the optimum generation technology can become more challenging in demand applications, including DHC networks, whose heat-to-electricity ratio varies daily or seasonally. These systems often require a combination of several generation technologies to optimise system energy performance on an annual basis. A portfolio of generation and storage technologies in these DHC networks is typically needed to help the system adapt to the demand requirements.

- **Bridge energy demand locations with generation.** The business case for co-generation applications can benefit from the existence of local heat end users that can absorb excess heat generated. These end users could be neighbouring industrial processes with a temperature-compatible heat demand or a local DH network. In the case of industrial co-generation applications, the possibility to export excess electricity to the grid as an add-on to the industrial site's core business can enhance the profitability of the site and provide additional flexibility to operations.

  DHC networks often require considerable infrastructure to distribute the heating and cooling from the generation site to end users. The necessary capital investment can only be reasonably paid back in areas with high population densities where significant heating and cooling demand can be ensured. These networks can be highly efficient and reduce their carbon footprint by taking advantage of locally available, renewable energy sources such as biomass, solar thermal and geothermal power, as well as surplus heat from industrial processes and natural cooling.

- **A great variety of energy sources can be used.** Co-generation technologies can operate within a wide range of fuels and energy sources, ranging from fossil fuels and waste-to-renewable energy sources such as biomass, geothermal and concentrated solar. Combining co-generation technologies with renewable sources provides a two-fold carbon benefit: energy savings through enhanced conversion efficiency levels and direct CO_2 emissions reduction achieved through the use of carbon-neutral energy sources. The final selection of energy sources for co-generation systems is highly dependent on diverse factors, such as local availability and energy prices.

- **Value flexibility**. Co-generation technologies provide a flexible bridge between heat and electricity. Both forms of energy can be balanced depending on end-user needs, so that either the electricity or the heat output is maximised over the other to meet system requirements. This co-generation feature allows multiple solutions and operating modes to be explored. For instance, industrial co-generation applications typically operate to meet a set heat output, which is required to sustain the industrial process. The electricity output in this case would fluctuate with the heat output for the specific established heat-to-electricity ratio. In contrast, the plant could also choose to maximise electricity generation during periods when electricity prices are attractive in comparison to fuel prices, thus compensating for the reduction in heat generation through the use of auxiliary boilers. Even in shut-down periods for maintenance work, when significantly less or no heat demand exists, an industrial facility may still decide to keep the co-generation unit in operation to export electricity to the grid, provided the system's design and size allow this alternative. The impact on heat supply of applying these options can be minimised with the use of thermal storage capacity and separate boilers on the site.

[10] Exergy is a measure to indicate to what extent energy is convertible to other forms of energy.

DHC networks can reach significant levels of flexibility depending on their supply system design. Apart from co-generation technologies, DHC networks can integrate other equipment, such as heat pumps, absorption chillers and thermal storage capacity, as well as free energy and renewable energy sources. These highly integrated networks can absorb power from the grid during excess electricity periods and convert it into heat for end uses through heat pumps integrated in the system. Conversely, the DHC networks can help mitigate electricity peak demand periods by providing heating or cooling from co-generation systems, thereby reducing electricity demanded by end users. Thermal storage capacity can also help reduce the fluctuation of heat supply produced by changes in the operating mode of the network.

How can policy and market regulations help to make the right energy technology choice?

Policies and market regulations can help unveil the benefits of co-generation technologies and efficient DHC networks. Market conditions should ensure transparent and fair fuel prices and reflect the real cost of electricity and heat generation to promote efficient use of energy. Cross-subsidies between heat and electricity markets should be avoided since they can result in artificially imbalanced energy prices. By promoting the most efficient use of low-carbon and renewable energy sources, energy policies can also help to provide a two-fold contribution to meet climate targets from the use of renewable sources, while achieving higher levels of energy efficiency in the conversion process to final energy.

Streamlined and clear interconnection standards that facilitate connection of co-generation sites to the distribution grid to export excess electricity can improve the business case of projects. By enabling a bi-directional flow of electricity from co-generation facilities to the transmission grid and vice-versa, these sites can maximise added value through system flexibility. Policy tools, such as strategic heating and cooling planning, can help identify cost-effective opportunities for co-generation technologies and DHC networks. These assessments identify, locate, quantify and characterise thermal sources and thermal end users in a specific region (Box 1). This information is critical when exploring locations for the implementation of new DHC networks or assessing possible upgrades or expansions of existing networks. In the case of industrial co-generation, heat mapping of the area surrounding the industrial site can help identify the possible opportunities for additional heat providers and customers. This information typically has a direct impact in the design phase of the project.

The policy and market conditions briefly described here have been key in the development of the projects analysed in this report (Table 1). The three industrial co-generation projects analysed in this report are interconnected to the local power grid and typically export electricity as part of their core business structure. For instance, policy measures jointly promoting low-carbon and efficient electricity under the Renewable Obligation Certificates in the United Kingdom were essential for the economic feasibility of the Markinch co-generation project. The project also could benefit from other policy measures, including the proposed future electricity market reform as a capacity mechanism incorporating demand-side response and storage.

The development of the DHC projects analysed in this report also benefited from policy programmes complementarily rewarding energy efficiency and the use of renewable energy sources. For instance, the Paris Climate Action Plan was taken into account in the choice of free cooling technology introduced in the Bercy Climespace cooling plant in Paris, France. The Marstal solar thermal DHC network integrating storage and biomass-based co-generation was similarly developed under the framework of the Danish government's climate targets aiming for 100% renewable heat and electricity generation by 2035.

Box 1 • Strategic heating and cooling planning trends in Europe

Article 14 of the 2012 European Energy Efficiency Directive (EE EU Directive) requires that member countries perform an assessment of the potential for further deployment of co-generation and efficient DHC systems by December 2015, as well as an analysis of policy strategies to be adopted by 2020 and 2030 to realise that potential. This exercise requires the development of national maps locating heating and cooling generation and demand points, as a basis for assessing cost-effective opportunities for these technologies to meet existing heating and cooling demands. This assessment includes:

- Heating and cooling sources, including electricity generation facilities with an annual generation greater than 20 gigawatt-hours (GWh), waste incineration plants, and existing or planned DH systems and co-generation sites.
- Heating and cooling demand points, including industrial areas with an annual consumption greater than 20 GWh and municipalities with a minimum plot ratio of 0.3.*
- The Directive also calls for the analysis of energy efficiency improvement potentials in existing DHC systems and a cost-benefit analysis for new installations or substantial refurbishment projects, including:
- Thermal electricity plants or industrial facilities generating surplus heat (at a recoverable temperature level).
- New DHC systems or existing networks with a thermal input greater than 20 MW where a new generation facility is expected.

* Plot ratio is defined as the ratio of the building floor area to the land area in a given territory.
Source: European Parliament and the Council (2012), Directive of the European Parliament and of the Council of 25 October 2012 on energy efficiency amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC, EP, Brussels.

Financing mechanisms

Financing is a key consideration in project development and continues to be a limiting factor in progress towards higher co-generation and efficient DHC penetration in countries across the globe. Co-generation technologies typically require greater upfront capital investments than conventional, separate thermal generation technologies due to the additional heat recovery equipment required. The investment costs for co-generation units using a gas turbine range from USD 900 per kilowatt electric (kW_e) to USD 1 500/kW_e (ETSAP, 2010a), in comparison to USD 900/kW_e required for a conventional open-cycle gas turbine (ETSAP, 2010b). In the case of natural-gas-based combined cycles (NGCC), the co-generation arrangement requires an investment between USD 1 100/kW_e and USD 1 800/kW_e or higher (ETSAP, 2010a), compared to USD 1 100/kW_e for a conventional NGCC with no heat export (ETSAP, 2010b).

Efficient DHC networks are also capital intensive due to the significant infrastructure needed to distribute heat or cooling from generation locations to end users. High costs can also be associated with the development and integration of the different energy supply sources and technologies that are to be linked to the network.

To encourage greater penetration of co-generation and DHC, economic feasibility studies need to clearly reflect the environmental and flexibility benefits of these technologies in economic terms within the local regulatory and market framework. This inclusive evaluative approach helps to ensure that projects are fairly assessed against conventional technology options.

Multiple mechanisms can be found to finance co-generation and efficient DHC projects, depending on the return on investment (ROI), the estimated uncertainty of not fulfilling the ROI in the expected time period, the acceptable risk for different parties involved and their financial situations. While large generation projects can often be self-financed or financed through the development of joint ventures, small- and medium-capacity systems developed by smaller entities typically require alternative financing mechanisms due to lower cash flow flexibility. Mechanisms used range from self-financed projects to diverse forms of third-party and public financing.

- **Self-financing.** This financing mechanism can be attractive when important net cash flows are available and the project aligns with strategic performance and environmental targets. The lack of other projects simultaneously competing for the same entity's funding can also influence the selection of this financing option**.**
- **Partial or total loan financing.** This type of financing can be an alternative mechanism to proceed with the development of a project and mitigate the risk of excessively affecting net cash flow of the entity. Loans can typically be provided for up to 80% of total construction cost at different interest rates, depending on the guarantee that involved companies can offer to secure payment of lent capital (EPA, 2013).
- **Third-party financing.** Companies or public entities with no ability to take on high upfront capital investments may seek an agreement with a third party, typically energy services companies (ESCOs). The latter own, finance and operate the co-generation or distribution system, and they provide heat and electricity to the energy-demanding body at set or indexed price rates. The ESCO can operate the facility for the entirety of the plant´s life (e.g. a build-own-operate scheme), or the plant can be transferred to the energy-demanding company after a specific operation time (e.g. a build-own-operate-transfer scheme).
- **Financing through joint ventures**. When developing projects that may present greater risks for individual companies (for instance, because of lack of expertise in a specific technology or because of a less prevalent position in a specific market), companies often form joint ventures specially designed to minimise potential investment risks. These joint ventures open a wide range of flexible financing solutions in which the parties involved contribute differently to project funding through diverse financing mechanisms, often involving plant operation and associated energy provision rights.
- **Public financing.** Co-generation and DHC projects can be fully or partially financed by governments, either through public energy companies with the same ownership rights on the facility, or through direct financial support, such as capacity grants or low interest loans.

How can policy and market regulations help mitigate market failures?

Policy measures including financial and fiscal incentives can help mitigate the impact of markets failing to reflect fair energy prices that reward the environmental benefits of efficient generation technologies, and to reduce higher investment costs for these types of projects. These incentives can be applied not only to new installations but also to refurbishments of existing facilities aiming to improve energy efficiency performance and reduce their carbon footprint. Freeing up investments for modernising and improving the operation of existing inefficient DH networks is critical to achieving decarbonisation of heat generation in countries that are bound to extensive, old and frequently poorly maintained heat distribution infrastructures (Box 2).

Box 2 • Russia: policy efforts to modernise DH infrastructure

Russia has the most extensive (173 100 kilometre [km] trench length of DH pipeline and 7 EJ DH sales in 2007), and oldest DH infrastructure in the world (many network lines are more than 100 years old). An estimated 60% of the Russian DH network needs major repair or replacement, and an estimated 20% to 30% of heat is lost in the distribution network before reaching consumers.

Heat tariffs in Russia do not reflect the real heat generation cost due to the existence of cross-subsidies between the electricity and heat markets, because part of heat production costs are allocated to co-generation-based electricity. This cross-subsidised system results in an artificially high electricity price for co-generation compared to less efficient conventional generation technologies, which in turn makes efficient co-generation technologies less attractive to investors. Imbalanced energy prices also do not incentivise consumers to use heat efficiently, because heat prices are rather low.

Policy efforts have been implemented in recent years to drive market conditions to reward energy efficiency. Significant efforts are still needed, but these policies will support network improvements and more efficient use of heat by consumers.

Sources: Euroheat&Power (2013), *District Heating and Cooling: Country by Country Survey 2013,* Euroheat&Power, Brussels; IEA (2009a), *CHP/DH Country Profile: Russia*, IEA Publishing, Paris.

Policy measures can either alleviate higher upfront investment requirements for project development or help reduce the associated operation and maintenance costs of systems. For instance, a fuel tax exemption system for co-generation units or efficient energy providers can help promote the progressive use of low-carbon fossil fuels and renewable energy sources for electricity and heat generation. Feed-in tariffs can ensure a higher price in comparison to the market base rate for electricity and heat exported to the distribution network from co-generation facilities. Different bonus conditions may apply, depending on the fuel or energy source used by the co-generation plant, or feed-in tariffs can be applied to the total electricity or heat generated at the site. Feed-in tariffs can also be applied at a fixed rate, independent of market-based electricity prices, or in combination with an obligation from distribution grid operators to purchase electricity from efficient generators, such as co-generation plants.

Long-term stability of energy policies and market regulations is key to securing investments in the deployment of efficient electricity and heat generation and distribution technologies. These policies enable a more accurate assessment of project ROI, minimise the risk for supply plants and grid operators, and encourage progressive deployment of efficient and low-carbon generation technologies.

The policy and market conditions briefly described above influenced the development of the projects analysed in the case study section of this report. The financing mechanisms used by the three industrial co-generation case studies range from self-financed projects to third-party financing. The Markinch biomass-based project in the United Kingdom was also awarded with a capacity grant to meet part of the investment requirements. Two of the other projects similarly benefit (or are very likely to benefit in the near future) from electricity export feed-in tariffs and fiscal incentives, including reduction in fuel taxes.

The DHC case study projects also benefited from fiscal and financial incentives, including capacity grants in the combined co-generation and storage project in Marstal, Denmark. Two of the three DHC projects used a total or partial loan financing mechanism.

Box 3 • India: financial and fiscal incentives for industrial co-generation

According to recent studies, the sugar industry in India holds the largest potential for industrial co-generation deployment in the country, accounting for 5.2 gigawatts (GW) of the total estimated 14 GW of potential co-generation in the overall industrial sector.

The government of India is pursuing this potential through financial and fiscal incentives specifically targeted to co-generation applications in the industrial sector. Bagasse-based co-generation plants benefit from a capital subsidy that ranges from INR 1.5 million to INR 1.8 million for privately owned sugar mills, applied to 65% of the unit capacity in MW. The subsidy also is available to existing cooperative or public sugar mills, up to a maximum of INR 80 million per project, and includes INR 4 million to INR 6 million per MW of surplus power exported to the grid for new public or cooperative sugar mills. Fiscal incentives are also provided to biomass-based co-generation projects, including 80% accelerated depreciation and concessional import and excise duties.

Tapping the total industrial co-generation potential in India would require wider policy programmes that also include non-bagasse co-generation applications. Measures such as a more comprehensive co-generation feed-in tariff system that includes biomass and other co-generation applications and open access without cross-subsidy surcharges could help achieve greater co-generation deployment.

Note: 1 USD = approximately 62.5 INR; Bagasse is a fibrous waste product generated in sugar mills after crushing and extracting the juice from sugar cane. This material can be used as a fuel, and it is categorised as biomass.

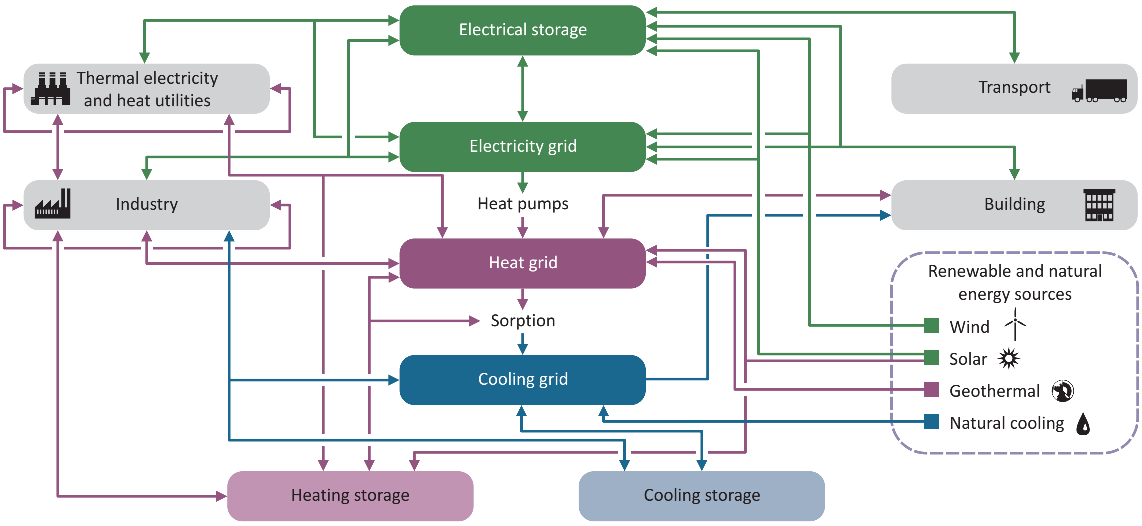
Sources: Singh, M., B. Singh and S.K. Mahla (2013), "Combined heat and power in commercial sector", *International Journal on Emerging Technologies*, Vol. 4/1, pp. 81-87; Ministry of New and Renewable Energy (India) (2013), www.mnre.gov.in.

Business structure

As greater shares of variable renewable generation technologies are integrated into the energy system, networks will face new challenges to effectively balance supply and demand due to the greater level of uncertainty in energy generation from these sources. Additionally, the increasing trend towards decentralisation in energy generation, driven by the aim of reducing transmission losses and improving energy self-sufficiency of end users, has increased the complexity of the energy system by introducing bi-directional energy interconnections between supply and demand.

In an energy environment of increased complexity, flexible technologies are highly valued: technologies that can rapidly adapt to operating loads, absorb or release energy when needed, or convert a specific final energy into another form of energy are increasingly important in energy systems. A number of technologies featured in this report offer this flexibility, including co-generation technologies bridging electricity and thermal systems, industrial sites transferring surplus heating or cooling to local DHC networks or absorbing excess heat from the thermal grid to convert it into electricity, DHC systems absorbing power from the grid through heat pumps and storing it as heat in excess generation periods, absorption technologies bridging heating and cooling in DHC systems, and electrical and thermal storage capacities contributing to smoother peak demand periods (Figure 3).

Figure 3 Interconnections of electricity and thermal energy in an integrated energy system



Key point • Electricity and thermal energy systems are complex and offer numerous opportunities for deep integration.

Flexible technologies as stand-alone units are not able to significantly improve the carbon footprint of energy systems. Instead, their adequate integration into energy networks will play a key role in achieving efficient and sustainable energy systems. Currently, diverse options exist to manage energy interactions between generation, distribution and end uses, but these options need to be integrated better into business structures in a market that is increasingly decentralised with multiple actors and bi-directional energy interconnections (Box 4).

Current business structures can range from conventional supply-and-demand (generator-and-user) contracts to more complex arrangements involving end users, distribution markets or generators. The most appropriate approach will depend on the technical specifications and needs of a particular generator or end user, as well as financial considerations, and is highly dependent on the particular context and internal business structure of the parties involved. For instance, whereas electricity transmission grids generally are extensive, heating and cooling transmission networks are highly localised because interconnections over larger areas are not technically or economically feasible. Therefore, electricity transmission grids tend to be centrally operated, while the operation of heating and cooling distribution systems is often vertically integrated within the local generating company. Additionally, the generator often may have a choice between different business structures, or may opt for a combination of several approaches, especially in the case of co-generators and integrated DHC networks that bridge electricity and heat markets. For example, an industrial co-generator could enter into a bilateral contract for heat supply and then export surplus electricity to the transmission grid operator at market rates.

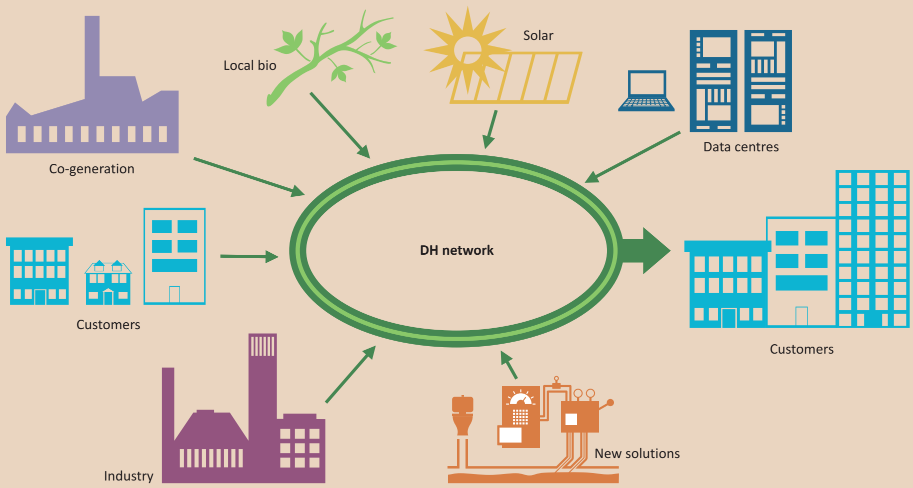
Box 4 • Sweden: Open DHC business model

Fortum launched the Open DHC business model in Stockholm (Sweden) in 2012 with the objectives of utilising the most efficient energy sources available and enhancing the profitability of the DHC system by minimising costs related to heat supply. Open DHC treats all types of thermal deliveries connected to the network equally based on the market price that is paid for any heat deliveries, regardless of production type or heat source. At the same time, only thermal deliveries from renewable sources or sources that have a higher conversion efficiency than the utility company can be accepted. Heating and cooling market prices are defined daily for three different types of surplus heat deliveries, including primary and secondary heat delivered to the supply and return pipelines of the DH network, respectively, and recovery heat delivered to the return pipeline of the DC network. The same mechanism is applied to DH and DC capacities of network users that help to reduce the utility company's required heat generation capacity, which can be achieved through demand-side management or thermal storages that reward lower overall heat/cooling end use. Open DHC encourages these synergies while seeking to ensure reasonable heating and cooling prices for DHC customers.

Energy in the Open DHC network can be produced by the utility company, by conventional customers or by any other operator connected to the network. Open DHC also allows the use of local waste heat that otherwise would be lost, thereby achieving a more efficient system by encouraging consumers to recover their excess energy. This option helps to improve overall system efficiency while reducing the emissions footprint related to thermal deliveries.

Last, best available technology is automatically connected to open networks. In this way, Open DHC is a concrete step towards smarter DHC that takes into account local energy sources while reducing the network's carbon footprint and ensuring transparent energy prices. In addition to the Open DHC model in Stockholm, Fortum has developed several Open DHC pilots in Finland, and these systems could be replicated in other networks across the globe.

Figure 4 • Open DHC business model



Source: Fortum representatives (2014), Personal communication.

Key point • Smart business models can help integrate a wide range of energy sources.

The wide diversity of intervening factors means that each project is best suited to a different business arrangement. Below are some of the major options currently available, as well as limitations and strengths for project developers to consider.

- **Generator and end-user contract structure**. Bilateral contracts can be established between generators and end users either through a sale or a purchase contract. For some applications, especially industrial co-generation, the entity can be either producer or user depending on supply/demand balance. This type of contract can provide generators with a stable revenue source, and end users with predictable long-term energy prices. However, depending on the specifics of the contract, this structure could limit the flexibility of a system (either on the supply or demand side), given the need to supply or purchase pre-determined amounts of heat or electricity.
- **Generator and market operator structure**. Generators can offer wholesale market bids to the electricity market operator, depending on the local electricity market structure. To be successful, this approach requires interconnection to the grid and attractive prices. This structure can accommodate systems that function as both generators and end users, allowing bi-directional flows, where the entity offers bids when operating at a surplus, and purchases energy at market rates when necessary. Selling into a market system can also provide a complementary revenue source for generators that have steady heat demand and surplus electricity. However, this structure also allows more uncertainty; fluctuations in electricity prices could make co-generation economically unattractive.
- **End user and distribution contract structure**. Contracts can be established between consumers and the distribution operator or retailers for the provision of electricity, heating or cooling. Within electricity retail markets, end users can choose the most attractive electricity supplier from competing retailers. Regarding heating and cooling in most cases, the end user can set up a provision contract directly with the generator, because the same entity often operates the generation and distribution aspects of a specific local network. The majority of these contracts are uni-directional from distribution to end user, rarely allowing consumers to export energy to the distribution grid and thereby limiting the system's flexibility.

How can policy help develop and implement tools to optimise integrated sustainable energy systems?

Current energy market structures and legal frameworks have limitations that prevent them from fully meeting the increasing flexibility needs of complex and highly integrated energy systems. For future energy systems, smart business models are needed to effectively manage multiple technologies and optimally balance complex interactions between supply and demand. These business structures should aim to minimise energy losses and optimise the use of sustainable local energy sources by considering the following aspects:

- Optimum management of multiple technologies with diverse generation patterns over time and flexible capabilities. This management includes finding optimal balances between variable carbon-free generation technologies, flexible low-carbon or carbon-free generation technologies, and storage capacity (thermal or electric).
- Flexible management of bi-directional energy flows among multiple generators and users. Generators (or consumers with surplus energy) that provide a good level of energy efficiency in both the generation and use of energy (as well as a low-carbon footprint) could have preferential access to interconnect with energy grids.

Energy policies and programmes can support the development of these business models and market mechanisms and improve the sustainability of infrastructure projects, through measures such as:

- Support research activities to explore and design sustainable business mechanisms that can meet the technical and societal needs of complex and highly interconnected energy systems.
- Support the implementation of smart business model pilots and promote international collaboration and experience sharing to help find optimum solutions for local contexts from the wide range of possible options.
- Ensure that these models reward flexibility, low-carbon footprint generation technologies and energy efficiency.
- Coordinate the development of local, regional and national strategic infrastructure deployment plans with developers of business models for energy networks, and define joint measures to minimise costs of future refurbishments, expansions or new installations; avoid missing opportunities to use locally available sustainable energy sources; and support the prioritisation of energy efficiency measures.

The diverse business structures and policy frameworks illustrated in the case studies of this report demonstrate the influence of policies and market mechanisms to encourage the uptake of flexible and efficient energy systems in different contexts and regions. For instance, the Nuevo Pemex industrial co-generation project in Mexico benefits from an energy banking system that has allowed efficient co-generators and renewable power generators to deposit excess electricity in the grid and import that power when needed. The Paris Climate Action Plan (Le Plan Climat de Paris) similarly has encouraged the adoption of free cooling to meet expected energy consumption and emissions targets, while the Princess Noura Bint Adbul Al Rahman University for Women (PNUW) in Riyadh, Saudi Arabia has established specific energy and performance metrics with possible penalties for underperformance to ensure that production and technical capacities are maintained.

Conclusions

Co-generation technologies and efficient DHC networks can provide significant added value in a sustainable energy future thanks to their multiple benefits. These benefits include CO_2 emissions mitigation and improved energy security through the enhanced conversion efficiency of the technologies, and improved flexibility resulting from the ability of the technologies to bridge electricity and thermal systems and to take advantage of a wide diversity of energy sources.

Despite these benefits, global deployment of these technologies is limited, and has remained stagnant over the last decade. Important barriers exist, mainly related to local energy price signals that poorly incentivise energy efficiency, lack of strategic planning on energy infrastructure and difficulty of ensuring long-term stability of energy policies.

The development of co-generation and DHC projects requires assessing the main parameters and local conditions that define a suitable environment for these technologies, identifying opportunities to use locally available energy sources, exploring possible financing mechanisms, and setting a flexible business structure that can help optimise possible interconnections with local energy players.

Policy strategies and market regulations can help make energy efficient technologies a cost-effective option, mitigate the impact of markets failing to reward energy efficiency by reinforcing the business case for these technologies, and support the development of smart business models for optimum management of highly integrated and complex energy systems.

The following section contains detailed descriptions of real co-generation and DHC projects that provide great examples of how barriers can be overcome and how opportunities within different local frameworks can be found to implement these technologies.

Co-generation and DHC Case Studies Compendium

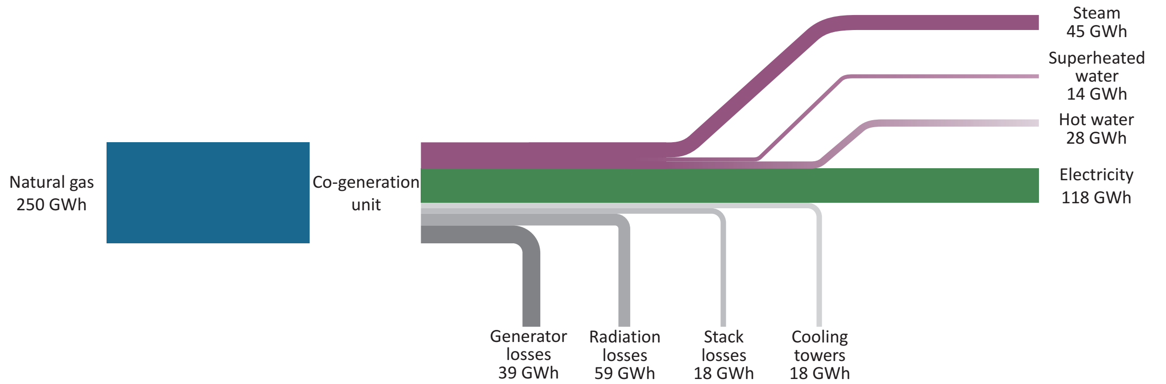
Industrial co-generation: Segovia, Spain

Case study information submitted by Acogen and Cogen Energía España.

Key facts:

The Eresma Cogen project is a co-generation unit at the Destilerías y Crianza del Whisky (Whisky DYC) distillery in Segovia, Spain (Figure 5). The distillery produces whisky, anise and gin. As of 2008, the annual total production of malt liquor from the distillery was 796 700 litres. The co-generation plant, which began commercial operation in May 2008 after a two-year project development period, is managed, operated and maintained by Cogen Energía España, and jointly owned with the distillery owners (InfoPower, 2008). The co-generation plant replaced the distillery's older conventional generation capacity; before this project, the distillery used boilers to generate heat. The project began as two distinct plants: one co-generation plant to provide heat and power to the distillery, and one plant to provide heat for the waste treatment process. Because of changes in the regulatory framework, the two units, each with a 6.5-MW gas engine and boiler system and operated by the same control centre, are now both categorised as co-generation (Table 2).

Figure 5 • Eresma co-generation system sankey diagram



Source: Cogen Energía España representatives (2013), Personal communication.

Project description

Energy supply

The Eresma Cogen unit has two 6.5-MW, 16-cylinder gas engines that produce electricity using 100% natural gas fuel, with an annual average fuel input of 902 terajoules (TJ) (lower heating value – LHV). Gas is imported from ENAGAS (originally *Empresa Nacional del Gas*), the owner and operator of the national gas transmission network. Two heat recovery steam generators produce steam from the exhaust gases (4 tonnes per hour [t/h] each), and compact heat exchangers produce superheated water at 140°C. The distillery also uses hot water from the cooling circuits of the gas engines. The unit always runs on a heat-controlled mode. The plant operates 24 hours a day, except during planned annual maintenance periods of five days.

Table 2 • Eresma Cogen capacity, generation and efficiency

	Electricity	Heating	Total
Installed capacity	13 MW_e	10 MW_{th}	23 MW
Annual average generation	113.4 GWh	87.2 GWh (314 TJ)	200.6 GWh
Annual average efficiency	45.3%	34.8%	80%

Sources: Cogen Energía España representatives (2013), Personal communication; Acogen representatives (2013), Personal communication.

Energy demand

The co-generation plant supplies heat and power to the following eight industrial processes within the distillery:

- Distillation column: 104 TJ heat load, 1.5 GWh electricity load.
- Rectification column: 53 TJ heat load, 0.4 GWh electricity load.
- Subproducts treatment: 70 TJ heat load, 1.3 GWh electricity load.
- Other distillation and heating (includes molasses concentration, malt water heating, grain water heating, maltery, and heating): 87 TJ heat load, 2.7 GWh electricity load.

The distillery's total heat load from the co-generation plant is 314 TJ, and its total electricity load is 5.9 GWh. The steam production from the co-generation plant meets 70% of the distillery's total steam demand of 11.4 t/h (82% of the total heat demand of 106.6 GWh). Conventional gas boilers are used to generate the 19.4 GWh of additional heat required to meet the distillery's demand. The system cannot supply heat to any third parties.

The 5.9 GWh electricity load meets all of the distillery's electricity demand, and makes up about 5% of the co-generation plant's total electricity output. Excess electricity above the distillery's demand is exported to the grid. If the distillery stops operating, the co-generation plant is also shut down. The plant is under no commitment to export electricity to the grid, and in the current business environment, exporting electricity is not economical when no heat is demanded by the industrial processes at the distillery.

Technology justification

Using co-generation over separate heat and power for these processes saves 280 TJ of energy each year, which is about 28.8% of the plant's total annual energy use, and avoids the release of 15 522 tonnes of CO_2 per year, about a 22% reduction.[11] The total cost savings associated with the Cogen Eresma plant is EUR 2.47 million.

The plant was sized to meet as much heat demand as possible given the limitations of the electricity grid. The existing infrastructure can only support a unit with up to 13 MW_e electricity capacity, so the plant has 13 MW_e of installed capacity; this capacity allows the plant to export as much electricity as possible while also supplying most of the heat demand at the distillery. Within this limitation, the plant supplies 70% of the distillery's heat demand and all of its electricity needs, and exports the remaining electricity to the grid. Because the total heat demand of the distillery exceeds the output of the co-generation plant, no thermal storage was included in the system.

[11] Compared to best available conventional sources: natural gas combined cycle power generation with 55% efficiency (LHV) and heat generation using gas boilers with 90% efficiency.

Economic and regulatory framework

National/regional regulatory context

Spain's national electricity grid operator, Red Eléctrica de España (REE), was created in 1985 when transmission services were unbundled from generation and distribution. In 1998, Spain's electricity market began the liberalisation process, and soon after, the market opened electricity generation and retail to competition, subject to regulation by the National Energy Commission (CNE). The 1998 liberalisation also created day-ahead and intra-day wholesale markets for electricity generation, though trading outside this market (such as through bilateral contracts and capacity auctions) is also permitted. Operador del Mercado Ibérico de la Energía (OMIE) operates these markets, where producers bid to generate electricity. Special regime generators, including renewables and co-generation, had two options for selling power into the grid; they could receive the fixed feed-in tariff rate, or they could operate like a typical generator and either bid in OMIE's wholesale markets or establish a bilateral contract for power generation (IEA, 2009b).

Lately the Spanish energy sector regulatory framework has undertaken deep changes, particularly with regard to incentives, due to the high cost of this programme and fiscal constraints. Until the middle of 2013, in addition to the feed-in tariff for electricity exported to the grid, which was adjusted quarterly based on Spanish gas prices, bonuses could be added for reactive power control, efficiency based on primary energy savings, operation with time discrimination and other potential services for system operation. Since July 2013, co-generation plants have stopped receiving all additional incentives, receiving only the feed-in tariff according to the prior framework (Boletin Oficial del Estado, 2013a). A new legislation entered into force in December 2013, this law proposed a feed-in tariff framework for co-generation systems that considers each plant's revenue, operational costs and initial investment to ensure a reasonable ROI (Boletin Oficial del Estado, 2013b). Specific parameters for the calculation of feed-in tariffs affecting co-generation plants were announced in February 2014, and site operators are currently assessing the impact of this new compensation system on the economic feasibility of these facilities.

Project financing

The co-generation plant was designed, built and commissioned by Axima Sistemas y Instalaciones, and is owned by Cogen Eresma, a company that is owned jointly by Cogen Energía España (90%) and the distillery owners, Beam Global Spirits & Wine (10%). The project's IRR made it economical, based primarily on savings compared to the distillery's previous separate heat and power generation. Its total cost was EUR 10.3 million, which was financed using the company's own funds and a shareholder loan. The project did not receive any preferential financing, subsidised loans or incentives for the initial investment in the project. The projected financial payback period is seven years, though this period will depend on regulatory changes and electricity prices.

Business structure

The Eresma Cogen plant, which is managed, operated and maintained by Cogen Energía España, sold electricity into the grid under a feed-in tariff scheme, providing a day-ahead schedule to the market operator, and receiving a fixed price for all electricity generated. To be entitled to receive the feed-in tariff, facilities were required to meet minimum efficiency conditions (IEA, 2009b) (Ciaretta and Gutiérrez-Hita, 2009).

The new feed-in tariff for co-generation plants affects the payback period for this plant. Prior to the changes, the co-generation unit at the Whisky DYC distillery received the fixed tariff, plus bonuses for reactive power and efficiency.

Lessons learned

The Cogen Eresma project would not have been possible without the supporting regulatory framework for co-generation that was in place at the time of its development, and the future of those regulatory supports will have an effect on the project's business model. Similar projects could be developed in other countries and regions with favourable policy environments; the regulatory framework and corresponding incentive mechanisms are key to providing the long-term stability necessary for secure investments.

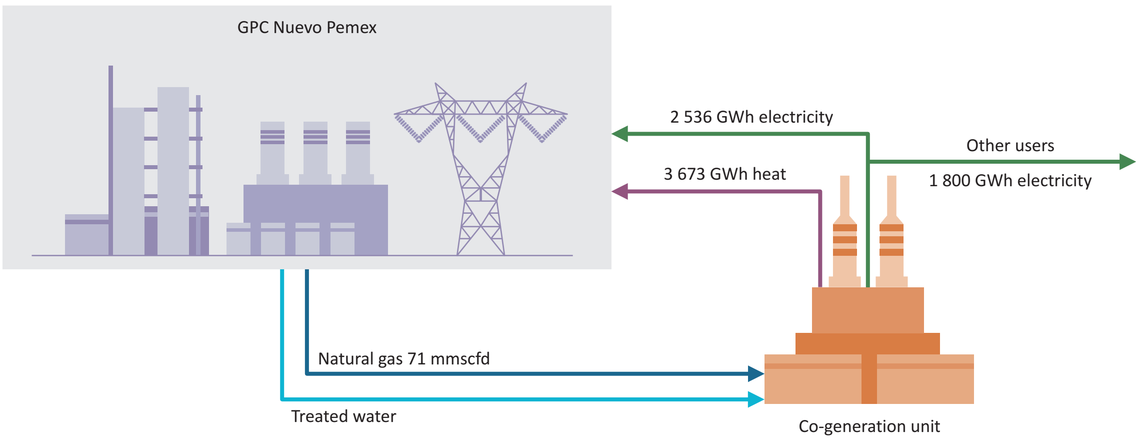
Industrial co-generation: Tabasco, Mexico

Case study information submitted by Pemex and Cogenera México.

Key facts:

The Petróleos Mexicanos (Pemex) gas processing complex (GPC), known as Nuevo Pemex, commissioned a new co-generation plant in 2013 (Figure 6). This unit produces heat and electricity for on-site use and supplies excess power to other off-site Pemex-owned industrial end users. The project allows Pemex to reduce energy costs by reducing electricity purchases from the CFE (Comisión Federal de Electricidad) state-owned grid to become more self-sufficient and to produce electricity more efficiently. The electricity produced by this co-generation project allows Pemex to save 30 million cubic feet of natural gas per day (mmscfd), and reduces carbon dioxide (CO_2) emissions by 430 ktCO_2 annually, as well as reducing nitrogen oxide (NOx) and sulphur oxide (SOx) emissions (Table 3).[12]

Figure 6 • Nuevo Pemex co-generation system



Sources: Cogen Energía España representatives (2013), Personal communication; Pemex representatives (2013), Personal communication.

Project description

Energy supply

The co-generation plant consists of two natural gas turbo generators, coupled with an exhaust gas heat recovery system. The unit has a total electricity generation capacity of 300 MW_e and heat generation capacity of 430 MW_{th} in the form of high-pressure steam (typical generation is 550 t/h, with the possibility of supplementary gas firing leading to a maximum production of 800 t/h). The twin turbo generators have an 18-stage compressor and a 3-stage turbine configuration and are entirely run on natural gas, which is produced at the GPC.

The plant's expected annual average energy input is 27 petajoules (PJ), reaching an efficiency of 81.4% annually on average. The co-generation plant has planned maintenance shutdowns of about 12.9 days annually, including some partial shutdowns.

[12] Compared to previous natural gas use at this and several other power generation sites.

Table 3 • Nuevo Pemex capacity, generation and efficiency

	Electricity	Heating	Total
Installed capacity	300 MW_e	430 MW_{th}	730 MW
Annual average generation	9 PJ (2 537 GWh)	13 PJ	22 PJ
Annual average efficiency			81.4%

Sources: Cogen Energía España representatives (2013), Personal communication; Pemex representatives (2013), Personal communication.

Energy demand

The co-generation plant operates to target a pre-determined heat output (heat-controlled mode) with the electricity generation fluctuating as per the established power-to-heat ratio. The totality of the heat produced – an expected annual average of 13 PJ – is used at the Nuevo Pemex GPC site, covering around 70% of steam needs, along with 2 537 GWh of electricity, of which 274 GWh (10.8%) covers the gas processing needs, while the rest is exported to other Pemex sites.

Heat is sent to the end user from the co-generation plant through a heating distribution network of 1.3 km, with a supply line of 0.6 m diameter, and a return line with 0.3 m diameter. The insulation thickness in the main lines is 0.203 m, made of 100% mineral wood insulation. Energy losses in the distribution network are monitored, to ensure that steam conditions at the end-use point meet process requirements. Provided that heat output control is used to operate the co-generation unit, the need to install heat-buffering capacity has not been identified, with the distribution network (including steam headers at different pressure levels) acting as storage.

The electricity not consumed by the Nuevo Pemex GPC, an average of 2 261 GWh, is provided to six industrial off-site processes:

- 6 refineries: 1 175 GWh electricity load.
- 6 gas plants: 165 GWh electricity load.
- 6 petrochemical plants: 80 GWh electricity load.
- 34 exploration and production processes: 300 GWh electricity load.
- 32 distribution facilities: 80 GWh electricity load.
- 20 pumping facilities: 80 GWh electricity load.

The remaining electricity load (annual average of 381 GWh) is fed into the national grid and distributed to 82 non-industrial sites.[13]

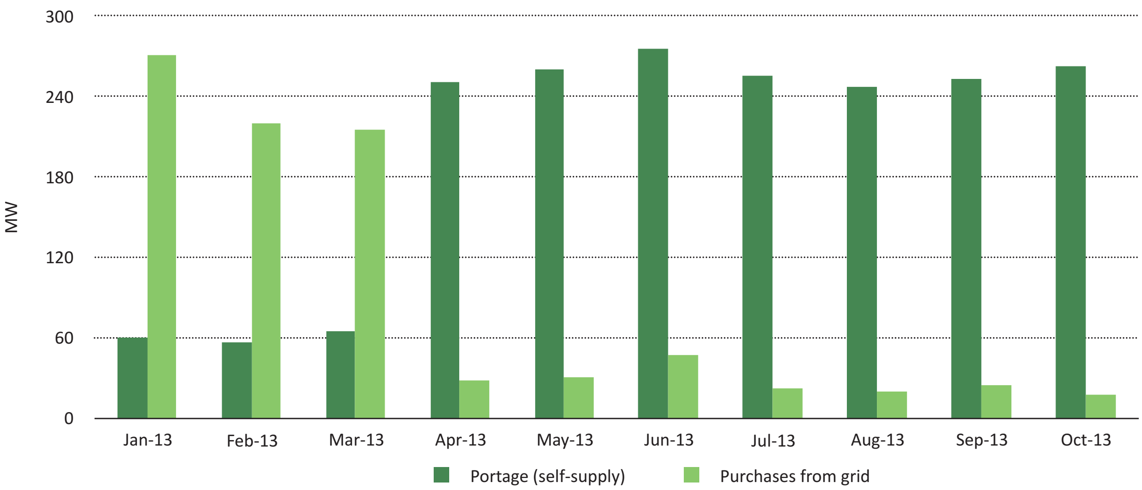
Technology justification

In September 2008, Pemex presented a plan to develop enough co-generation potential in the short term to increase its level of self-sufficiency, and in the long term, to become fully self-sufficient by developing the rest of the co-generation potential – estimated at about 3 GW, mainly in existing refining, petrochemical and gas processing plants. Within the framework of this strategy, the Nuevo Pemex co-generation project was developed to reduce electricity and heat generation costs, increase energy efficiency, and improve supply reliability. Pemex and the contractor for this project selected sites based on the level of electricity and steam demand, as well as unit costs. The co-generation

[13] These values are annual average electricity generation numbers, and could vary depending on operating conditions and steam demand from the Nuevo Pemex GPC. Any excess electricity, after meeting the GPC and other on-site end-user demand, is exported to the grid; this is not limited to 381 GWh.

project allowed Pemex to reduce purchases from CFE by 150 MW and reduce its own lower-efficiency generation by about 140 MW, while also reducing natural gas use and emissions (Figure 7).

Figure 7 • Off-site industrial processes electricity purchases



Sources: Pemex representatives (2013), Personal communication.

Economic and regulatory framework

National/regional regulatory context

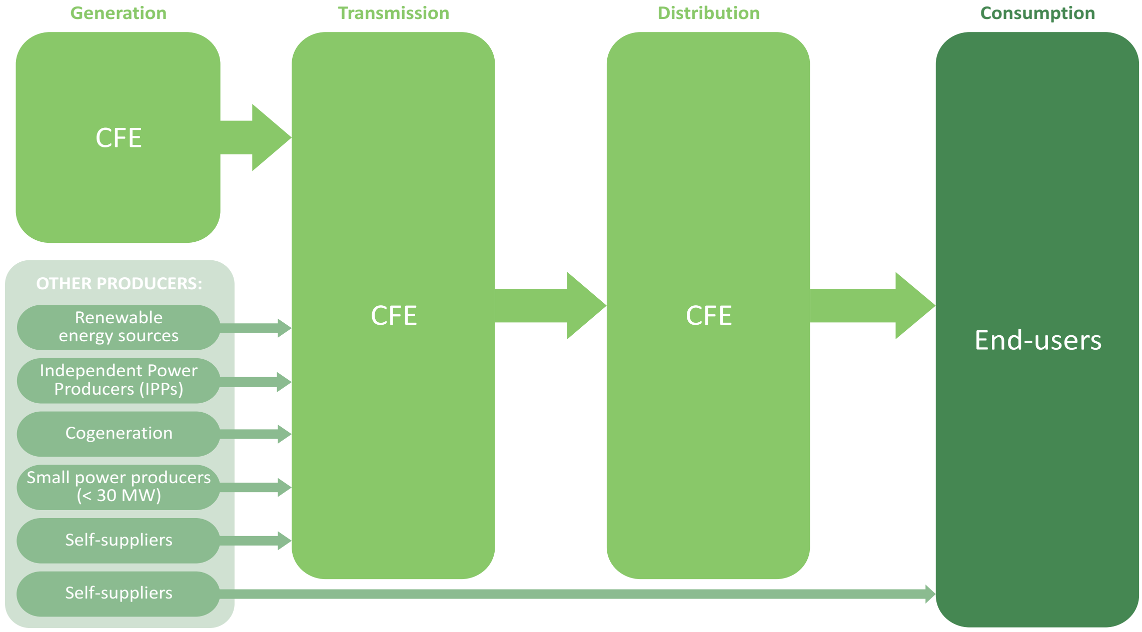
The Mexican electricity market is largely controlled by the semi-public utility CFE (Figure 8). CFE owns over 75% of the installed generation capacity, and it owns all transmission and distribution assets in Mexico (EIA, 2012). A 1992 amendment to the Public Electricity Service Act of 1975 marked a turning point for the Mexican electricity sector, partially opening the electricity sector to privately owned electricity producers, including foreign investors. With a permit from the Comisión Reguladora de Energía (CRE), private companies that fall into one of the following categories are allowed to produce power and connect to the grid: self-suppliers, co-generation projects, small producers (< 30 MW), power producers that are importing electricity for self-supply or generating for export, or independent power producers (IPPs) with 25-year power purchase agreements (PPAs) to sell all output to CFE. With the 2008, 2011 and 2012 regulatory changes, efficient co-generators and renewable power producers were also permitted to take advantage of the energy banking system, and costs for connection to the grid and transmission of electricity were lowered (OECD, 2004, 2013).

The private sector is responsible for the majority of the growth in capacity in recent years, almost quadrupling from 2000 to 2008, from 4.3 GW to 21.0 GW (Sener, 2009). In 2011, co-generation installed capacity was 5% of the national total, and 32% of privately owned capacity (Cereceda, 2013).

Overall, Pemex now owns about 2 GW of electricity generation capacity, some of which will be retired. In 2012, the company produced 7 600 GWh for own-use, but about a third of it was produced with low efficiency;[14] additionally, Pemex still did not meet all of its own needs, and purchased 2 500 GWh from the grid.

[14] On average, retired generation capacity produced with 28% electrical efficiency.

Figure 8 • Mexican electricity sector structure



Project financing

The service provider took on the investment of USD 504 million in the co-generation plant and associated transmission lines. Maintenance costs are estimated at USD 7.7 million per year. The project developer used a financing structure based on 37% of the investment in provided capital and 63% bank credit; the project did not rely on any government support. It did not receive any subsidies or preferential financing, but did benefit from the new regulation allowing lower transmission costs and the elimination of back-up charges ("demanda facturable") for co-generators that self-suppliers previously paid to CFE (Davis et al., 2012). Project developers estimate approximately a 5- to 6-year payback period for this project, considering the savings from avoiding electricity purchases from the grid and replacing inefficient electricity and heat generation with efficient self-generation of electricity and heat recovered from exhaust gases.

Business structure

Pemex contracted with a third-party service provider to develop and operate the Nuevo Pemex co-generation project. This contractor has a 20-year contract with Pemex to operate the co-generation plant using natural gas provided by the Nuevo Pemex GPC and to send electricity to off-site Pemex-owned industrial processes and to the grid, upon the condition of providing steam and electricity to the Nuevo Pemex GPC site.

On an annual basis, the co-generation unit meets about 90% of overall electricity demand, due to variability in demand from the end users. The remaining 10% of demand is met with electricity imported from the grid. For end users of the electricity (which are Pemex subsidiaries), prices paid to the third-party plant operator are fixed. Overall, prices are more than 40% lower than purchasing directly from CFE through the grid (see Table 4). A fixed amount is paid to the grid operator for transmission services.

Table 4 • Nuevo Pemex electricity prices

Level	Schedule	CFE price* (USD/kWh)	Voltage level	Transmission charge for efficient co-generation (USD/kWh)	Total delivery cost (USD/kWh)
1	Baseload	1.022	High	0.0337	0.817
2	Intermediate	1.227	Medium	0.0674	0.851
3	Peak	2.053	Low	0.1347	0.918

Note: Average cost, not including capacity charges, of Pemex electricity demand in different time periods.

Source: Cogenera México and Pemex (2013), "Cogeneración eficiente: Proyecto de Nuevo Pemex", Green Expo México, Mexico City, 25-27 September 2013.

Participation in Mexico's energy banking system also gives the Nuevo Pemex co-generation project some flexibility to deal with demand variability. The banking system allows generators to "deposit" extra electricity generation when a surplus of generation exists and "withdraw" that energy at a later date when generation does not meet demand. Because of the generation system and the on-site fuel availability, Pemex also has significant flexibility in its own power generation levels (Cogenera México, 2013).

Though the project mainly produces heat and power for use by the Nuevo Pemex GPC and other Pemex processes, it also sells excess electricity to the CFE grid when electricity output surpasses demand at prices indexed to short-term prices defined by CFE. However, because no preferential tariffs are provided to efficient generators, the Mexican electricity market offers little incentive to become an electricity exporter, except when demand variability creates a surplus of electricity.

Lessons learned

Future co-generation projects in Mexico would benefit from further streamlining of the regulatory process for co-generation, including simplification of the process for receiving permits, standardisation of technical specifications, and better alignment of electricity tariffs with fuel costs to incentivise co-generation capacity that provides surplus generation to the grid (CONUEE and CRE, 2009).

The same scheme can no longer be replicated at large scale, since Nuevo Pemex covered most of the demand not linked with steam generation in refinery and petrochemical processes, but smaller-scale projects could be possible. Most of the Pemex industrial sites produce electricity using conventional steam-condensing turbines.

Industrial co-generation: Fife, Scotland, United Kingdom

Case study information submitted by Combined Heat and Power Association (CHPA) and RWE Innogy.

Key facts:

The Markinch biomass project consists of a 60 MW_e[15] co-generation plant at the Tullis Russell Paper Mill, in Fife, Scotland, making it the largest such plant in the United Kingdom (RWE npower renewables, 2013). The plant is owned by the UK subsidiary of RWE Innogy, which in January 2014 changed its name from RWE npower renewables to RWE Innogy UK. The construction phase of the project is close to completion and is currently being commissioned. This co-generation unit will provide heat and power to the Tullis Russell Paper Mill, as well as supplying power to the grid. The plant will replace a 60-year-old coal- and gas-fired power plant, which was retired on 30 August 2013. The plant allows Tullis Russell to continue operating in its current location, reduce emissions and help Scotland come closer to meeting its target of 30% of energy consumption from renewable sources by 2020 (IEA, 2012). RWE estimates that the plant will avoid 0.25 megatonnes (Mt) fossil CO_2 emissions annually.[16]

Project description

Energy supply

The plant consists of a single circulating-fluidised-bed (CFB) boiler and a condensing/pass-out steam turbine. An air-cooled condenser will provide cooling to the plant. The plant will be typically operated in heat-controlled mode, supplying heat to the paper mill as demanded, whereas the electricity generated will fluctuate according to steam demand and the pre-determined power-to-heat ratio. Electricity generation will be maximised only in the case of the mill being turned down (lower heat demand) or in an environment of peak electrical demand from the grid and attractive prices. At maximum heat generation, the electrical capacity is 39 MW_e (gross), and with no heat demand, the plant's electrical capacity is 60.3 MW_e (gross) (Tables 5 and 6).

Planned maintenance is expected to occur twice per year, and the total annual planned shut-down time will be about 30 days, or around 8.2% of the total operation time. RWE expects the co-generation unit to provide simultaneous heat and power to the paper mill for about 89% of the time, equivalent to about 7 800 hours per year, accounting for planned and unplanned outages. The rest of the time RWE will supply steam to the paper mill from three gas-fired boilers, and electricity for the paper mill will be imported from the grid. Co-generation unit outages will coincide with paper mill outages whenever possible.

The plant's average annual energy input will be 4 800 TJ, of which 99% comes from biomass fuel, and the remaining 1% from natural gas. Of the biomass, about 90% will be recovered waste wood supplied through a number of contracts, and 10% will be virgin biomass. RWE estimates that the plant will require 405 Mt of biomass per year.

[15] Maximum electricity generation capacity.

[16] CO_2 savings are calculated based on displaced carbon emissions from the previous power plant and electricity imported by the paper mill. The calculation also considers carbon savings associated with electricity exported to the grid by the CHP plant, compared to grid average emissions published by the Department of Energy & Climate Change (DECC). CO_2 emitted by sustainably-sourced biomass is considered carbon neutral. Carbon emissions calculations for the plant account for gas burned on start-up and in the back-up gas boilers, as well as carbon emissions from processing and transport of wood fuel to the CHP site. Wood fuel carbon emissions were estimated using the Ofgem carbon emissions calculation tool (Ofgem, 2012).

Table 5 • Markinch capacity and efficiency

	Electricity	Heat	Total
Capacity (max heat output mode)	39.1 MW_e	88 MW_{th}	127 MW
Capacity (max electricity output mode)	60.3 MW_e		
Annual average efficiency	24%	28%	51%
Net efficiency in max heat output mode	-	-	68.3%
Net efficiency in max electricity output mode	-	-	31.5%

Sources: CHPA representatives (2013), Personal communication; RWE Innogy representatives (2013), Personal communication.

Table 6 • Markinch steam characteristics

	Steam characteristics
Steam flow	Average 57 t/h, maximum 120 t/h
Steam pressure	2.9 and 10.3 bar
Steam temperature	165 and 230°C

Sources: CHPA representatives (2013), Personal communication; RWE Innogy representatives (2013), Personal communication.

Energy demand

The Markinch co-generation plant will supply up to 120 t/h of steam and 21 MW_e of electricity to the primary end user, the Tullis Russell Paper Mill. Additional electricity will be exported to the local grid, with enough additional capacity to support electricity exports even when the paper mill is operating at full load. Typical exports to the grid will be about 30 MW_e. However, peak heat demand (about 100 t/h of steam) from the paper mill will occur for only 2 to 3 hours per year.

Technology justification

RWE chose biomass as the primary fuel for this plant because of the strong regulatory support for biomass co-generation plants under the UK's Renewables Obligation. RWE identified an opportunity to develop the plant more economically by primarily using recovered wood fuel, rather than mainly virgin wood fuel.

Boiler and fuel-handling technologies were selected to ensure compliance with environmental regulatory requirements as well as to attain high thermal efficiency; RWE decided to use fluidised-bed technology that would be well-suited to a plant with some fuel flexibility. CFB technology in particular was selected due to its lower emissions characteristics, its ability to achieve higher cycle efficiencies, and its capability to allow the plant to operate with a single boiler unit.

Economic and regulatory framework

National/regional regulatory context

The Electricity Act of 1989 privatised the previously state-owned organisations responsible for electricity generation, transmission and distribution. Market liberalisation in the United Kingdom continued in the 1990s and early 2000s, with increasing competition and vertical deintegration.

Electricity prices are determined competitively, and generation, transmission and distribution are unbundled, though some vertical reintegration has occurred, prompting proposals for new electricity market reform legislation. Exports of electricity to the grid occur in the framework of the UK's British Electricity Trading and Transmission Arrangements (BETTA), through which generators can sell electricity to suppliers on a single wholesale market. Additionally, medium and large generators are required to participate in the grid operator's Balancing Mechanism to help balance supply and demand on the grid. Plants must also provide basic levels of reactive power and frequency response (IEA, 2012).

Currently, the UK government promotes low-carbon and efficient electricity generation through several incentives, most notably the Renewables Obligation. The proposed electricity market reforms would add several other mechanisms to facilitate long-term investment in infrastructure, promote low-carbon technologies, and increase electricity supply security. Proposed policies include a feed-in tariff for low-carbon electricity generation, a carbon price floor outside the European Emissions Trading System (EU-ETS), an emissions performance standard, and a capacity mechanism that incorporates demand-side response and storage (IEA, 2012).

Co-generation projects can be certified under the Combined Heat and Power Quality Assurance programme (CHPQA) run by the Department of Energy and Climate Change (DECC). The voluntary annual certification program provides an efficiency benchmark for "high-quality" co-generation projects, and is used to determine eligibility for various incentives, including Enhanced Capital Allowances, exemption from the Climate Change Levy, tax benefits, and eligibility for Renewables Obligation Certificates (ROCs) for biomass and waste-to-energy co-generation plants (DECC, 2013). For April 2014 to March 2015, the Renewables Obligation level for suppliers in Scotland will be 0.244 ROC/MWh (Ofgem, 2013b). Biomass co-generation plants will receive 2 ROCs per MWh sold to the grid in 2013 (Ofgem, 2013a). The Office of Gas and Electricity Markets (Ofgem) estimated the value of an ROC in 2013 to be about GBP 46 (Ofgem, 2013b).

Project financing

The plant went through a number of stages of cost assessment. After an initial basic feasibility study using budgetary information provided by plant suppliers indicated the positive economics of the project, a detailed front-end engineering design study was conducted, and RWE began negotiations with the customer to develop the energy supply contract. A detailed discounted cash flow model was developed to evaluate the project and support the financial investment decision. The capital cost for the project, which was financed from RWE's balance sheet, was more than GBP 200 million, and the annual operations and maintenance cost is about GBP 6 million.

The Scottish government awarded the project a Regional Selective Assistance grant of GBP 8.1 million, based on the safeguarding of jobs within an area identified for regional aid (Scottish government, 2009). The grant contributed to financing for the site preparation, as well as additional expenses associated with building a co-generation plant instead of a power-only plant, such as additional gas boilers and steam distribution pipework.

The project, once operational and CHPQA-certified, will also benefit from revenue from ROCs. The ROCs are an essential aspect of the Markinch project's financing; without them, the plant would not have a positive spread between fuel cost and revenue for electrical output, and would not have been built. The sales of power and heat from the plant make up a relatively small part of the total plant revenue.

The Renewables Obligation only relates to electricity generation. At present, the plant does not qualify for the Renewable Heat Incentive (RHI), which provides a feed-in tariff for heat generated from renewable sources (Ofgem, 2013c). Therefore, when assessing potential users of heat in the area, the project had no additional incentive to build a system that would allow exports of heat beyond the paper mill demand. If the plant decides to qualify for the RHI in the future, RWE would consider supplying additional heat to other customers.

Business structure

The biomass at the plant will be supplied through several contracts, the largest being with SITA UK, a national waste management company, which will provide recovered waste wood from its existing sites in Scotland and northern England (SITA UK, 2012). Additionally, the Scottish Forestry commission will provide 75 000 tonnes of small round wood from sustainably managed forests. Because the paper mill imports virgin pulp rather than producing its own pulp from logs, it does not produce significant amounts of biomass waste suitable for use in the co-generation plant.

The power and heat supplied to the customer will be priced based on agreed unit tariffs, specified in a 20-year energy supply contract, which are partially indexed to the cost of biomass fuel. The plant will export excess power to the national grid at market rates for electricity. The plant will also participate in the Balancing Mechanism, with bid offer prices set by RWE.

Lessons learned

As in many other markets, developing the Markinch co-generation facility required financial incentives to successfully compete with cheaper conventional sources of heat and power. The implementation of this biomass-based co-generation project was commercially viable only thanks to regulatory support from the UK government. Expected revenue from certificates under the UK's Renewables Obligation, in particular, was essential to making this project financially feasible. After CHPQA certification, the Markinch co-generation unit will also be eligible for a number of other incentives that make this project attractive. The UK's policy environment encourages investment in efficient co-generation by creating a level playing field that allows co-generation to compete with conventional power and heat generation technologies, and by promoting stability that allows investors to make long-term financial decisions.

DHC: Marstal, Denmark

Case study information submitted by PlanEnergi Nordjylland.

Key facts:

The Sunstore 4 project is a DH plant in Marstal, Denmark that has been developed to demonstrate the potential to produce DH using 100% renewable energy assisted by a large heat storage capacity in the production system. The project also sought to demonstrate flexibility of renewable energies (solar, biomass and electricity from local renewable sources) relative to the costs of the energy sources. These objectives were targeted under the broader goal of achieving low-cost solar thermal heat production using storage that could be adapted to regional conditions and energy loads in other European countries.

The Sunstore 4 plant combines solar thermal energy, a biomass boiler paired with an ORC unit, a compressing heat pump and 75 000 cubic metres (m^3) of local heat storage. By combining these elements, the system is able to utilise low storage temperatures, while also reducing required storage size and heat losses from using a larger storage pit. The Sunstore 4 project is an extension of previous solar heat production for DH uses in Marstal (Table 7). The entire Sunstore DH plant is estimated to save roughly 10.5 kt CO_2 annually.[17]

Since implementation of the production system in 2011-12, the Sunstore 4 project has demonstrated 10% better efficiency of the new solar collectors compared to the previous solar installations due to technological improvements.

Project description

Energy supply

The Sunstore 4 plant was conceived as a demonstration of a 100% renewable energy system for DH that is flexible and can deal with the challenges related to a variable solar flow. The storage pit and heat pump system also provide possible power system benefits beyond the network. For example, electricity can be converted into heat and stored during periods of high wind power production or can offer additional economic benefits when electricity prices are low.

In 1994, Marstal Fjernvarme A.m.b.a., the DH provider, successfully built a small-scale demonstration solar collector heat plant, which led to the development of a solar heating plant connected to the local DH network. By 2001, the solar heating plant accounted for roughly 9 000 square metres (m^2) of solar collectors and an accumulating tank capable of providing district heat for short-term supply (two to three days). The solar plant was expanded again in 2001 under the Sunstore 2 project to a total of 18 365 m^2 of collectors, and a heat storage pit of 10 000 m^3 was completed in 2004 to achieve longer storage times.

The Sunstore 4 project is an extension of this capacity, adding 15 000 m^2 of additional solar collectors and 75 000 m^3 of new pit storage in 2011-12 (Figure 9). The Sunstore 4 plant also comprises a 4.0 MW CHP unit. This unit consists of a low-emission wood chip thermal oil boiler with a 750-kW ORC unit and a 1.5-MW thermal heat pump.

The new collectors also cost nearly 12% less than the previous additions, and storage prices are roughly EUR 28/m3, resulting in average DH production prices of EUR 50 to EUR 60 per megawatt-

[17] The Marstal heating plant (including the Sunstore 4 plant) provides 31 996 MWh of district heat (see Figure 10). If this heat were provided using a conventional diesel boiler (assuming a higher average operating efficiency of 90%), the plant would produce roughly 9.5 kt of CO_2 annually. In addition, the ORC unit produces 3 233 MWh of electricity, which saves roughly 1 kt of CO_2 (applying the 2011 average of 302 gCO_2/kWh for electricity supply in Denmark).

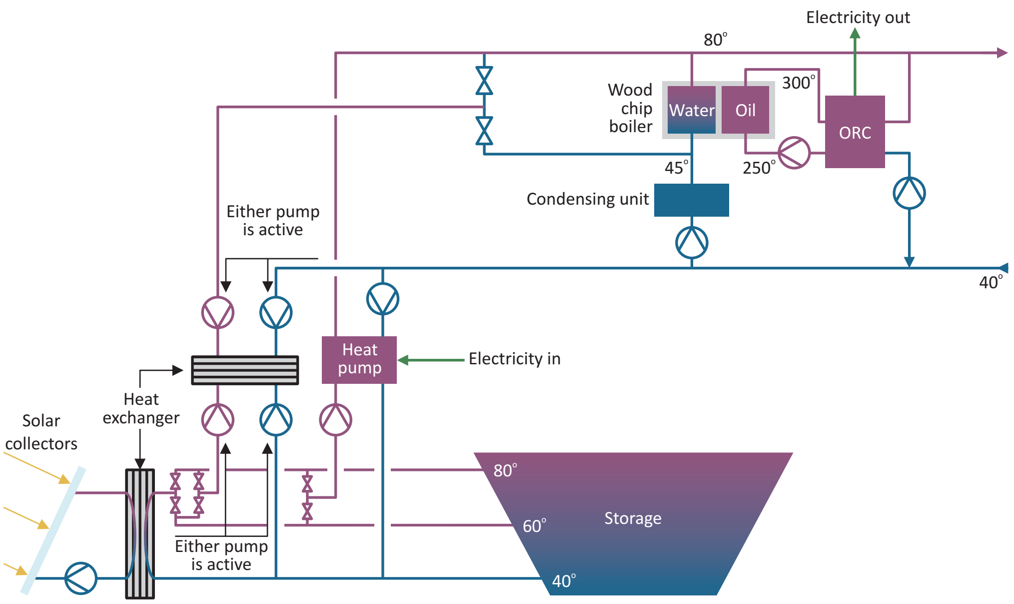
hour (MWh). The heat pump has operated at an average COP of 3.1, or 310% efficiency, while the biomass boiler and ORC unit have a combined output efficiency of 100%.

Table 7 • Historic expansion of the Marstal Sunstore projects

Year	Installation	Capacity
1994	Small-scale solar demonstration	75 m^2
1994-2001	First Sunstore solar DH implementation	9 043 m^2 solar collectors and 2 100 m^3 accumulating tank
2001-04	Sunstore 2 project	Additional 9 322 m^2 solar collectors and 10 000 m^3 collector pit
2011-12	Sunstore 4 project	15 000 m^2 solar collectors, 75 000m^3 collector pit, 1.5 MW heat pump and ORC unit
	Total installation:	**33 365 m^2 solar collectors, 87 100 m^3 storage, 1.5 MW heat pump and CHP unit**

Source: PlanEnergi Nordjylland representatives (2013), Personal Communication.

Figure 9 • Process flow diagram describing Sunstore 4 plant additions



Source: PlanEnergi Nordjylland representatives (2013), Personal Communication.

The Sunstore 4 plant operates differently throughout four seasonal periods, where the solar collectors provide Marstal with DH throughout the summer while also loading heat in the storage pit. From the end of September, when temperatures are still relatively moderate, the solar collectors supply the DH network, while either the wood chip boiler or the heat pump supplements heat demand, depending on the cost of electricity. In the winter, the wood chip boiler is operated regularly to supply required heat, while back-up boilers converted in 2005 from waste oil to bio oil may be operated for a few hours on cold days to meet total DH demand. The heat pump can also be operated during these periods, although at higher electricity prices. In February, the solar collectors start to supply heat to the storage pit again, while the wood chip boiler continues to operate to meet total demand until April.

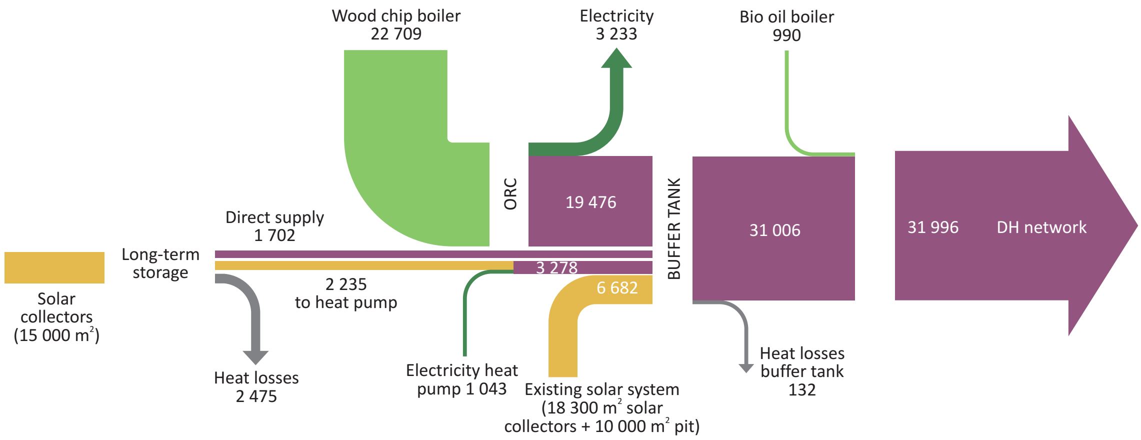
The Sunstore 4 plant consumes approximately 81 terajoules (TJ) of wood chips and an additional 1 gigawatt-hour (GWh) of electricity (for heat pump operation) annually (Table 8). It produces roughly 88 TJ of annual heat generation (including nearly 17 TJ of heat output from the Sunstore 4 solar collectors and heat pump), for roughly 109% system efficiency. The ORC unit also produces 3.2 GWh of electricity. When paired with the existing solar collector network and Sunstore 2 storage pit, the entire Marstal DH supply produces roughly 115 TJ (about 32 GWh) of annual heating output, for a total DH efficiency of 142% (including electricity output from the ORC unit). Losses from the Sunstore 4 storage pit account for roughly 9 TJ of energy annually (Figure 10). A system buffer tank also incurs slight heat losses (roughly 0.5 TJ).

Table 8 • Annual energy input and output of Marstal DH system

	Fuel energy input (MWh)	Heat output / (Losses) (MWh)	Electricity output (MWh)
Wood chip boiler with ORC	22 709	19 476	3 233
Solar collectors (direct heat)	0	8 384	0
Heat pump	1 043	3 278	0
Bio oil boiler	1 065	990	0
Losses (buffer tank)		(132)	
Total	**24 817**	**31 996**	**3 233**

Source: PlanEnergi Nordjylland representatives (2013), Personal Communication.

Figure 10 • Sankey diagram (MWh) of Marstal DH production



Source: PlanEnergi Nordjylland representatives (2013), Personal Communication.

Energy distribution and demand

The Sunstore 4 plant functions best using low return temperatures; that is, the production of the solar plant under local conditions is approximately 1% higher if the average return temperature is lowered 1°C. The Marstal DH network, therefore, uses local storages (typically 110- to 160-litre tanks) at consumer substations to absorb incoming (flow) temperatures and to provide low return temperatures (roughly 33°C in winter and as high as 40°C in summer). These consumer substations also minimise required network piping to households and help to reduce network heat losses. The consumers own the substations in the houses and are responsible for their operation. Supply (forward) temperatures are regulated according to outdoor temperatures and typically are between 72°C (summer) and 76°C (winter).

The Marstal DH network supplies roughly 1 550 buildings, which are mostly single-family households built prior to 1970. Heat sales in 2012 were roughly 26 500 MWh (95 TJ); heat losses from network distribution accounted for nearly 5 500 MWh (or roughly 17% of system output). Network piping for Marstal DH can be as much as 30 years old, although it is being continuously upgraded with polyurethane piping with polymer casing. System flows (rates and temperatures) are also monitored regularly, and consumer substations with high return temperatures are visited to manage demand control.

Technology justification

Only two DH plants in Denmark used solar energy for large-scale heating production prior to 1994. While solar radiation represents approximately 200 times the amount of energy used in Denmark, meeting system demand through adjustable flows (depending on seasonal solar fractions) was a major barrier to full-scale implementation of year-round solar heating, especially because most DH plants run at constantly high flows. Early in 1994, Marstal DH consequently implemented a demonstration solar collector plant with an accumulating tank to cover roughly 15% of heat demand. The demonstration plant was so promising that Marstal DH decided to expand solar capacities in the DH system.

Before choosing the Sunstore 4 concept, Marstal DH compared different alternatives for district heat production combining solar, storage, biomass and heat pump technologies. Comparisons were made using heat production prices for the different combinations with the expectation that the new district heat plant would have a 20-year lifetime. The Sunstore 4 concept was chosen as the best combination of solar, storage and renewable technologies. It offered the least expensive heat production prices that would also demonstrate the potential for 100% renewable energy use in the district heat network.

Economic and regulatory framework

National/regional regulatory context

DH in Denmark is regulated by heat planning guidelines, which stipulate that municipalities are responsible for ensuring that heat production by utility companies is the least expensive option for consumers while meeting targets set by the Danish government. Current targets for heat production call for 100% renewable energy systems for all electricity and heat production by 2035. Fossil fuels are consequently taxed heavily, while solar energy production is not taxed. In addition, taxes on electricity used for heat pumps were reduced in early 2013. Biomass will be taxed beginning in 2014, although the feed-in tariff for electricity produced using biomass will still be quite favourable (11 Euro cents per kilowatt-hour [kWh]).

Project financing

Total investments for the Sunstore 4 plant were EUR 15.5 million with EUR 4.1 million in support from the European Commission and project financing with municipal guarantee for 100% of the investment. The interest rate for the loan is 3.05% for a 25-year annuity loan. Yearly maintenance is approximately EUR 50 000, and the expected payback period is less than 10 years (including the support).

Business structure

Danish DH utilities are non-profit companies. Marstal DH is a consumer-owned cooperative, and more than 95% of buildings in Marstal are customers. New customers have also been added from a nearby village using a 2-km transmission pipe, and additional customers can join the network free of charge. Marstal DH has applied this policy to attract more households, thereby reducing the costs of the Sunstore 4 project and annual maintenance by economies of scale. Typically, new customer installations are revenue positive after four years.

Annual district heat prices are decided at the yearly general assembly to which all customers are invited. The heat price is a combination of a fixed price based on the size of the building and a variable price, which is determined based on annual consumption. Metering is wireless, and payment is per kWh consumed. Households can be penalised for high return temperatures to ensure overall network efficiency, although the utility company will typically send a technician to address any potential problems at households if this is the case.

Lessons learned

The Sunstore 4 project is an innovative plant that has exceeded expectations and demonstrated that solar thermal energy with storage can supply year-round district heat. Sunstore 4 produces heat at roughly EUR 50/MWh to EUR 60/MWh, which is considerably lower than previous DH production prices of EUR 70/MWh from heat produced using bio oil.

Between 2 000 and 4 000 people from Denmark and elsewhere visit the Marstal DH project each year, and similar concepts will be developed in other regions of Europe. While design and implementation will be the same for similar plants in other regions, energy prices for produced heat (or cooling) and electricity will affect the market viability of a similar project. Existing policy and financing support to these technologies will also influence project economics. If alternatives are cheaper, the Sunstore concept will not be cost-effective. Interest rates on investments will also affect the feasibility of the Sunstore concept.

DHC: Paris, France

Case study information submitted by Climespace GDF Suez.

Key facts:

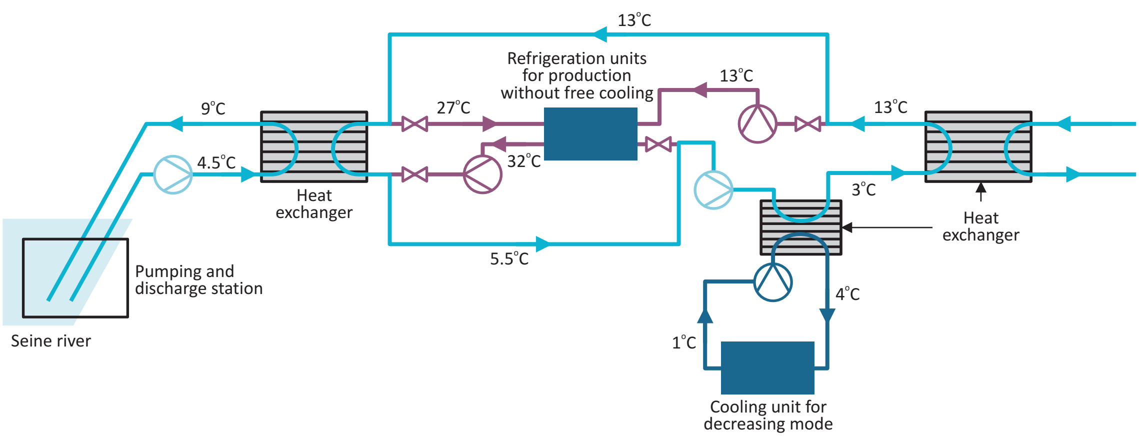
The Bercy cooling plant is a district cooling facility in Paris, France. The facility has been developed as a cooling production plant with "free cooling capacity"[18] using river water from the Seine River. The Bercy project was built over six phases between 1995 and 2009. It consists of seven electrical centrifugal chillers, four river water pumps, condensing and evaporating circuits, and on-site generator equipment for emergency and ancillary electricity demand (Figure 11). The plant has a current total generation capacity of 44 MW, and it supplies more than 40 clients along 10 km of network. Free cooling at the Bercy plant has been applied since the end of 2009, and since then, the average COP of the plant's chillers increased by 34%, with maximum COPs of 20 having been achieved. The plant is estimated to avoid 7.4 $ktCO_2$ annually.[19]

Project description

Energy supply

The Bercy cooling plant is an independent extension of the Climespace district cooling network in Paris that was opened in 1991 and now constitutes the largest district cooling network in Europe, distributing chilled water over 71 km to more than 520 clients. In total, the Climespace district cooling network accounts for eight cooling production sites, including the Bercy production plant and two other sites along the Seine River that now use free cooling as well. The Climespace network also includes three energy storage sites, including one chilled water storage system and two ice storage plants, and a new geothermal energy plant will be added by the end of 2013. When finished, the entire Climespace network (chillers, storage and new geothermal plant) will have a total nominal cooling capacity of 285 MW.

Figure 11 • Process flow diagram of Bercy cooling plant



Sources: Climespace GDF Suez representatives (2013), Personal communication; Mairie de Paris (2007), "Le plan climat de Paris: plan de lutte contre le réchauffement climatique", www.paris.fr/pratique/energie-plan-climat/le-plan-climat-de-paris/le-plan-climat-de-paris/rub_8413_stand_69591_port_19609.

[18] "Free cooling" is a term used that is associated with the use of "free" or available natural resources to provide partial or full cooling to buildings. In this case study, free cooling is used as a cooling assisted application for overall district cooling provision.

[19] Includes CO_2 emissions from refrigerant releases. CO_2 emissions savings for this project are 5.5 kt/year without refrigerant emissions.

In 2012, the total Climespace network delivered more than 410 GWh of chilled water for district cooling.

Chilled water production by means of free cooling typically occurs in the winter season when river temperatures are low enough to use free cooling. At the Bercy plant, free river water cooling has contributed to important electrical savings since 2009. The highest monthly electrical savings during winter have equaled as much as 400 MWh of electricity (or nearly 60% of average monthly electricity consumption during those months if the use of free cooling had not been available). Partial free cooling is also possible at slightly warmer river water temperatures, and a total of 3.2 GWh of electricity were saved at the Bercy plant between January 2010 and March 2013, or roughly 8% of total energy consumption for that period. This savings corresponds to 1 568 tonnes of CO_2 emissions reduction.

When paired with free cooling improvements made in the two additional Climespace production plants, total annual Climespace COP has reached nearly 4.03 in 2012 (or 403% efficiency), which is a 30% improvement over 2002 Climespace network COP levels. Potable water consumption for Climespace network cooling production also decreased by 50% over 2002 levels.

The Climespace cooling network operates at working supply temperatures of 2°C to 4°C, and network return temperatures are roughly 10°C. Each of the seven chillers in the Bercy plant has a nominal cooling capacity of between 3.75 MW and 9.5 MW, with nominal electric power between 0.8 MW and 1.9 MW, respectively. Annual Bercy electricity consumption is roughly 47 TJ, although this level depends on river temperatures and the amount of free cooling achieved each year. Annual sales are roughly 198 TJ, for a total annual network efficiency of roughly 420%.

Free cooling using the Seine River is used to reduce return temperatures when river temperatures are below 8°C. River water is typically below 5°C during the coldest winter months, and 100% free cooling may be used at these temperatures using river water pumps and heat exchangers. In warmer months, if river water temperatures remain below 8°C, partial free cooling is still possible. Once river temperatures go above 8°C, the network uses only the conventional chillers to meet cooling demand. These constraints are due mainly to network contractual delivery temperatures, although Climespace must also monitor river water return temperatures. For environmental reasons, highest rejected water temperatures cannot exceed 30°C, and the temperature difference between river water and reject water cannot be higher than 5°C.

Since free chilling or partial free chilling is dependent on the aforesaid thresholds, total cooling production in free cooling mode can fluctuate at the Bercy plant. For instance, average daily water temperatures were higher in 2011, leading to only 1.6 GWh of free cooling production in the Bercy network, for a total savings of roughly 3% of annual energy consumption. By contrast, electricity savings in 2010 were roughly 11% of total annual electricity consumption at the Bercy plant.

Energy distribution and demand

Bercy cooling distribution serves more than 40 clients, including predominantly offices and commercial space, for nearly 55 MW of subscribed power.[20] Some hotels and institutional buildings are also connected to the network, and additional buildings can be added to the network so long as they are geographically within the distribution network and sufficient hydraulic and thermal availability is present. Most buildings in the existing network were built in the last 25 years, and the total floor area cooled by present district cooling production is more than 700 000 m^2. The average

[20] Total subscribed power is greater than peak production capacity, although peak demand by all clients is highly unlikely given building demand profiles.

operational cooling demand is 18 MW, and peak demand can reach 30 MW.[21] Pipes 0.6 m in diameter are used for both the supply and return lines; polyurethane insulated pipes with polymer casing account for 80% of the Bercy network. The remaining 20% of network distribution consists of pipes insulated with foam glass and polyurethane. Maintenance and distribution improvements are expected every 15 years.

Flow rate, supply and return temperatures, piping losses, heat losses and network pressure are all monitored throughout the Bercy network, and pressure, flow rate and temperature are measured at each delivery point. These data are used to establish planning strategies for the network to increase energy production efficiencies and to forecast cooling demand and energy supply according to expected weather conditions. Climespace also uses this analysis to work with clients to understand cooling use, although energy audits of individual buildings are done independently.

Technology justification

The Climespace district cooling network in Paris has historically exploited free cooling from cooling towers throughout the network, although this technology has not produced significant reductions in net energy consumption for chilled water production because of the high energy consumption of the tower fans. When outdoor wet bulb (humidity) temperatures are low enough to satisfy the requirements of the operating chilled water temperatures, free cooling can be taken directly from the cooling towers. However, the higher benefits from river water free cooling resulted in a cooling production strategy to invest in river water free cooling for improved system efficiencies.

A five-year study was conducted between 2003 and 2008 to measure free cooling capacity at the Bercy plant. During the study, water temperatures fell below 5°C for roughly 6% of the year. Approximately 17% of the year had river temperatures between 5°C and 8°C. Given these results, river water free cooling capacity was added to the Bercy plant, and the use of free cooling has since allowed substantial energy savings. Like free cooling from the cooling towers, river water free cooling is still dependent on local conditions (water temperatures). However, the annual capacity, as demonstrated in the five-year study and subsequent use of the Seine River, offers much greater potential free cooling capacity than additional cooling tower capacity.

Economic and regulatory framework

National/regional regulatory context

The Bercy cooling plant was constructed through a concession agreement by the city of Paris under a public service contract.[22] Free cooling at the Bercy plant was part of a strategic decision by Climespace to improve network energy efficiency and respond to the Paris Climate Action Plan (Le Plan Climat de Paris). This plan seeks to reduce energy consumption and GHG emissions in Paris by 25% by 2020, while also increasing renewable energy use by as much as 25% during the same period (Mairie de Paris, 2007).

Project financing

Total capital expenditures for the Bercy cooling plant were EUR 34 million, including the initial installation of the energy plant and the on-site generators. Approximately EUR 350 000 of that investment can be attributed to works associated with the implementation of free cooling using the

[21] Average cooling demand refers to the typical (average) operational cooling output supplied for network demand. By contrast, average daily cooling load (MWh) refers to the typical daily cooling energy consumed throughout the course of a day (or average cooling demand multiplied by average hours of operation).

[22] A concession agreement is a form of public-private partnership under which a private firm enters into agreement with government to provide public services with certain exclusive rights to operate, maintain and/or make investments in a public utility (such as a district cooling network).

Seine River. The project was financed using a 20% equity-to-loan ratio with an expected 15-year payback period.

Project financing

Total capital expenditures for the Bercy cooling plant were EUR 34 million, including the initial installation of the energy plant and the on-site generators. Approximately EUR 350 000 of that investment can be attributed to works associated with the implementation of free cooling using the Seine River. The project was financed using a 20% equity-to-loan ratio with an expected 15-year payback period.

Business structure

Climespace manages and operates the entire Parisian district cooling system, excluding electricity supply. Under the concession agreement from the city of Paris, the district cooling network can be expanded but only in the area covered by the concession. In recent years, the Climespace network has experienced an annual increase of about 15 MW of subscribed connected power.

As a utility company exceeding 400 GWh of energy sold, Climespace needs to comply with the French CEE (Certificat d'économies d'énergie), which places some constraints and penalties on energy providers that are not complaint with energy efficiency standards. The CEE also provides some financial benefits to providers that are compliant with energy efficiency targets. To date, Climespace has met required efficiency targets and has not placed any constraints on subscribed contracts with clients.

Lessons learned

The Bercy project and Climespace network have demonstrated that district cooling using free cooling is an effective way to face present and future energy and environmental challenges for cooling buildings in high-density cities. High-efficiency district cooling using free cooling sources can be developed to meet increasing demand for comfort cooling in office and commercial buildings, and it can also help to reduce risks for peak electricity demand, especially in warmer summer months. While free cooling using the Seine River is limited by river water temperatures, it still provides net benefits to the system. Geothermal energy, such as the new plant being added to the Climespace network, and energy storage systems could also reduce the need for extra installed cooling capacity, while also decreasing peak electricity demand and strengthening grid infrastructure.

Different types of piping material could have been used in the Bercy network, and these considerations will be taken into account as the network is updated over time. Existing steel piping in the network requires internal protection layers and is subjected to higher levels of corrosion when compared with other materials. Leakage detection and more isolation valves could also be used throughout the network to monitor and control flow, and energy storage, which has not been applied to the Bercy network to date, could provide additional benefits similar to the current cooling towers in the larger Climespace network. An ice slurry likewise would help provide better energy density in the Bercy network.

DHC: Riyadh, Saudi Arabia

Case study information submitted by Millennium Energy Industries.

Key facts:

The Princess Noura Bint Adbul Al Rahman University for Women (PNUW) in Riyadh, Saudi Arabia commissioned Millennium Energy Industries (MEI) to build the world's largest operating solar heating project in 2010. The large-scale solar thermal DH application was opened in July 2011. The project provides space heating and hot water needs for nearly 40 000 students and staff in combination with the university's conventional diesel boilers (Figure 12). The solar system accounts for 36 610 m^2 of rooftop flat-plate collectors, and it includes 996 m^3 of storage capacity in six buffer tanks to store excess heat during times of high solar radiation or low demand for hot water. The PNUW solar thermal project is estimated to save nearly 52 million litres of diesel and 125 $ktCO_2$ during its expected 25-year system life, in comparison to standard diesel boilers.

Project description

Energy supply

The PNUW solar heating project was commissioned to provide clean DH solutions for the university campus. To meet the extreme conditions of the Riyadh desert, including desert sandstorms and both freezing and high operating temperatures (70°C to 90°C), the PNUW solar heating project required a sealed solar system and solar equipment that could withstand freezing temperatures on cold nights while maintaining high efficiencies on hot days. Design considerations also included hydraulic balancing (heat distribution) and friction loss control to prevent system stagnation[23] and varying heat load profiles, as well as a custom fastening system that can sustain wind loads up to 160 kilometres per hour (km/h). Regular cleaning is also required to treat fine dusts from desert storms.

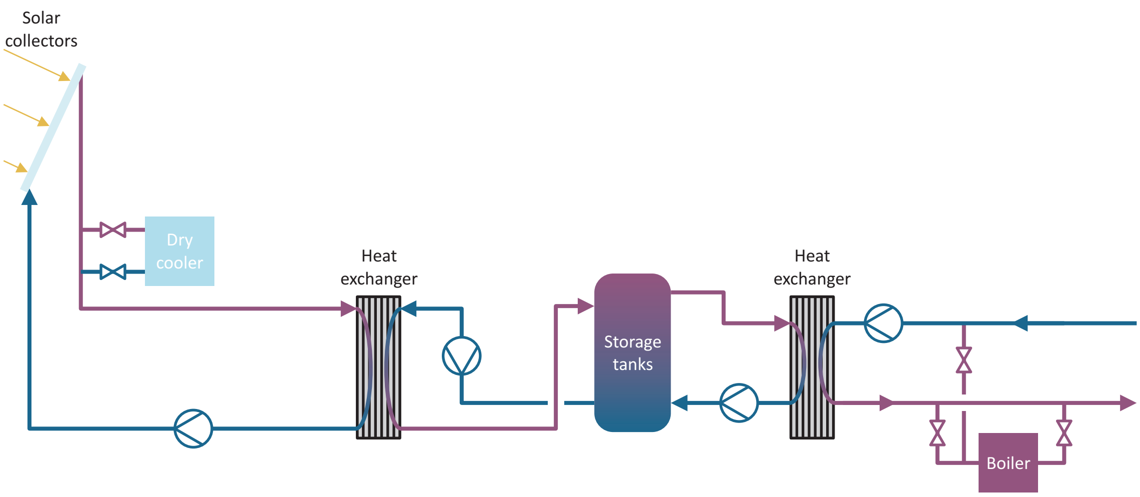
Performance results of the installed system, in comparison to theoretical performance yields, demonstrated in late 2011 that system yield was close to expected results (91%). Losses during testing were most likely from dust accumulation on collectors and possible thermal losses from piping and system equipment. Demand for temperatures above normal operating levels at certain times during the day also contributed to some efficiency reduction. Many of these issues will be addressed with system maintenance and continued experience with the solar thermal network.

The PNUW solar thermal system uses 3 616 large (10 m^2) flat panel collectors that minimise the need for piping and that have a high efficiency at high working temperatures. The solar application uses a Tichelmann pipe system divided into six zones for hydraulic balancing to allow parallel connections up to 110 m^2 between collectors (Figure 12). The Tichelmann system also limits the number of necessary regulating valves and limits pressure losses to manageable values, while allowing for emptying in case of stagnation.

[23] Stagnation, or overheating due to insufficient heat rejection relative to heat absorption within the solar thermal network, is an important issue in the design of solar thermal systems. Due to the varying heat loads of the PNUW district heating system (from student presence on campus and timing of demand), the PNUW system had to be sized to prevent excessive heat build-up within the system. Daily storage in the buffer tanks accommodates some of this excess heat; although low demand in summer months also had to be taken into account in the ultimate sizing of the network.

The six buffer tanks can also be heated to 100°C in a secondary circuit to avoid stagnation, and dry coolers are occasionally used to maintain system temperatures. Finally, an anti-freeze, glycol-water mix is used to protect the system against temperatures as low as -15°C, and solar circulating pumps are used to circulate the heat transfer fluid between the collectors and storage tanks.

Figure 12 • System diagram of the PNUW solar thermal DH plant



Sources: MEI representatives (2013), Personal communication; Heron, Chris (2013), "Princess Noura University (PNUW) solar heating system (2013)", Global Solar Thermal Energy Council, http://solarthermalworld.org/content/princess-noura-university-pnuw-solar-heating-system-2013.

The 3 616 solar collectors have a total nominal generation capacity of 25 MW with a heat generation capacity of 17 megawatts thermal (MW_{th}). The collectors provide supplemental heat to the university DH network's eight conventional diesel boilers, which have generation capacity of 8.5 MW each and a peak capacity of 68 MW_{th}. Average annual efficiency of the solar collectors is 43%, with an annual heat output of roughly 25 000 MWh. The conventional diesel boilers, which have an average nominal operating efficiency of 85%, output roughly 22 500 MWh annually (Table 9). This total does not include distribution losses, which can be as much as 10% to 15% of heat output.

Table 9 • PNUW district water heating energy input, outputs and efficiencies

	Fuel energy input (MWh)	Heat output (direct) (MWh)	Average efficiency (%)
Diesel boilers	26 390	22 430	85
Solar collectors	0	25 229	43
Total	**26 930**	**47 659**	**177***

Source: MEI representatives (2013), Personal Communication.
* The system efficiency shown here only reflects direct heat output relative to net fuel input. It does not include solar efficiency relative to potential remaining solar input, nor does it include distributional losses.

The operation and output of the solar thermal plant vary throughout the year, depending on ambient temperatures and university heating demand. During the summer period, the thermal demand of the DH network is typically less than 30 MWth, which the solar collectors are capable of supplying almost independently of the conventional boilers. In general, the solar thermal collectors provide enough heat during this period to fill the buffer tanks with water at 93°C during the first hours of the morning sun. Throughout the rest of the day, the solar thermal system continues to provide hot water needs to the campus while maintaining storage temperatures, and by nightfall, the remaining storage heat from the buffer tanks is typically able to meet system heating needs until early morning. When the buffer tanks can no longer provide hot water demand, the diesel boilers provide remaining supply. This diesel supply generally is for less than two hours in the early morning during summer months.

During colder winter months, the solar collectors reduce net diesel consumption in the DH network by heating the boiler return line. The eight boilers produce a maximum supply temperature of 90°C, where average return temperatures are near 72°C. The solar system raises return temperatures by a minimum of 3°C, thereby lowering required heat input by the boilers.

Energy distribution and demand

The PNUW DH network supplies space heating and hot water to 13 university faculties, covering a total heated floor area of 36 160 m^2. The DH network is 6.25 km in length with both supply and return lines at 0.152 m in diameter. All supply and return lines are fibreglass insulated (0.05 m insulation) with metal casing.

As heating demand varies across hot summer days, cold desert nights and cool winter months, total heating supplied to the network differs throughout the year. Daily average load for the network is roughly 15 MWh, where daily peak load can be as much as 48 MWh.

To avoid stagnation in the solar heating system and to ensure that heat demand is met efficiently, the university DH network is monitored and managed by a sophisticated Building Management System (BMS). The BMS includes energy meters, pressure safety valves, pressure and temperature indicators, and stagnation monitors in the solar collector network. The BMS also measures daily solar insolation and efficiency values, as well as system flow rates and supply and return temperatures. The collected information allows the BMS to improve operations based on district heat demand. This control by the BMS includes turning off the conventional boilers during daytime hours when the solar network is able to supply required district heat. The BMS also allows automatic commissioning logistics for timely start-up of heat supplies to avoid system idling.

Technology justification

The initial PNUW request for proposal issued by the Saudi Arabian Ministry of Finance considered the use of concentrated solar power, although MEI recommended the use of fixed solar collectors because of their lower capital expenditure and maintenance costs. Technical and commercial analysis of solar options also showed that flat panels were better suited to the extreme conditions of the arid desert climate, especially because fixed collectors avoid damage to moveable parts, such as the joints of tracking systems. The flat panel system also uses less space than other proposed solar technologies.

Fuel choice for the network boilers was also considered in the system design. Although current operations use diesel, the boilers have been equipped with dual burners for future introduction of liquefied petroleum gas (LPG) fuel to allow for continued energy efficiency improvements relative to fuel price and efficiency targets. This dual burner installation will support long-term goals of improving overall PNUW DH efficiencies.

Economic and regulatory framework

National/regional regulatory context

The PNUW project was developed under a broad set of objectives, including both national and university targets to reduce overall energy demand and increase sustainable energy supply in the energy mix. The project also serves as a demonstration for future projects that can be integrated into the broader national energy plan to improve energy efficiency and increase renewable energy supply.

Project financing

Total investment for the PNUW solar system was USD 23 million. Yearly maintenance is approximately USD 450 000, and the financial payback period is expected to be less than five years, depending on the cost of diesel fuels. This expected ROI was estimated compared to global diesel prices and opportunity costs for national oil savings.

Business structure

MEI has a five-year operations and maintenance contract with PNUW that includes technical operation, performance monitoring and a preventative maintenance programme. System performance and maintenance are also occasionally monitored by a third-party consultant who verifies that the DH system is meeting specific energy and performance metrics. Penalties can be incurred if performance indicators do not meet these metrics, although this kind of non-compliance has not been an issue to date. Expansion of the system is also possible if new university divisions are added, but such growth is unlikely in the near future, because the university was recently constructed.

Lessons learned

The PNUW solar thermal application demonstrates that solar DH is a viable technology in the Middle East and North African regions and that sustainable renewable energy systems can reduce conventional fuel use while also reducing emissions. The PNUM project shows that the choice of solar collectors and the proper sizing of system equipment are important in the planning of system design. These design elements are especially critical to avoid stagnation within the solar thermal system, although network distributional temperatures are another design element that could be considered for similar projects to lower required input heat energy and improve overall system efficiencies.

The PNUW solar thermal project illustrates that cost reductions and design optimisation can be achieved if solar systems are designed at early stages along with other system components. In desert locations such as Riyadh, design procedures will differ from conventional systems due to solar heat gain variables and safety considerations for large projects. Nevertheless, when planned carefully, solar technology can be a cost-effective solution for DH energy supply.

The IEA CHP and DHC Collaborative and Related Initiatives Supported by the IEA

The IEA CHP and DHC Collaborative was initiated in 2007 to accelerate deployment of cost-effective, clean co-generation and efficient DHC technologies, leading to reduced CO_2 emissions and increased overall efficiency of energy systems through increased use of waste heat and low-carbon renewable energy resources. The Collaborative also seeks to provide a platform for stakeholders to share best practices, policies, experiences and applied solutions with regard to these technologies. Collaborators include governments, international organisations, regional industrial associations and private sector collaborators, including equipment suppliers and utility companies.

This initiative has already completed several publications that provide a vision of co-generation and DHC energy potential, along with an overview of policy best practices and recommendations of options to consider when implementing these policies. The Collaborative results have also highlighted the benefits of an integrated energy system approach that uses co-generation technologies to assist in balancing electricity production from variable renewables. For more information about the Collaborative, please visit www.iea.org/chp/.

In addition, the Implementing Agreement for a Programme of RD&D on District Heating and Cooling, including the Integration of Combined Heat and Power (DHC IA), is a multilateral technology initiative supported by the IEA. The nine member countries of the DHC IA deal with the design, performance and operation of distribution systems and consumer installations. In operation since 1983, the DHC IA is dedicated to helping make DHC and co-generation powerful tools for energy conservation and the reduction of environmental impacts of supplying heat. For more information, please visit www.iea-dhc.org.

Abbreviations and Acronyms

2DS	2 degrees scenario
BETTA	British Electricity Trading and Transmission Arrangements
CFE	Comisión Federal de Electricidad (Federal Electricity Commission)
CHP	combined heat and power
CHPQA	Combined Heat and Power Quality Assurance
CNE	Comisión Nacional de Energía (National Energy Commission)
CO_2	carbon dioxide
CRE	Comisión Reguladora de Energía (Energy Regulatory Commission)
DC	district cooling
DECC	Department of Energy and Climate Change
DH	district heating
DHC	district heating and cooling
ESCO	energy service company
GHG	greenhouse gases
GPC	gas processing complex
IA	implementing agreement
IPP	independent power producer
IRR	internal rate of return
LHV	low heating value
NGCC	natural gas combined cycle
OECD	Organisation for Economic Co-operation and Development
Ofgem	Office of Gas and Electricity Markets
OMIE	Operador del Mercado Ibérico de la Energía
ORC	organic Rankine cycle
Pemex	Petróleos Mexicanos
PNUW	Princess Noura Bint Abdul Al Rahman University for Women
PPA	power purchase agreement
RD&D	research development and demonstration
REE	Red Eléctrica de España
RHI	Renewable Heat Incentive
ROC	Renewables Obligation Certificate
ROI	return on investment

Units of Measure

°C	degree Celsius
EJ	exajoule
EUR	Euro
GBP	British pound
GW	gigawatt
GWh	gigawatt-hour
GW_{th}	gigawatt thermal
INR	Indian rupee
km	kilometre
kt	kilotonne
kW_e	kilowatt electric
kWh	kilowatt-hour
m	metre
m^2	square metre
m^3	cubic metre
mmscfd	million standard cubic feet per day
Mt	megatonne
$MtCO_2$	megatonne of carbon dioxide
MW	megawatt
MW_e	megawatt electric
MW_{th}	megawatt thermal
NO_x	nitrogen oxides
PJ	petajoule
SO_x	sulphur oxides
t/h	tonnes per hour
TJ	terajoule
TWh	terawatt hour
USD	United States dollar

References

Acogen representatives (2013), Personal communication.

Boletín Oficial del Estado (2014), "Orden IET/107/2014", www.boe.es/boe/dias/2014/02/01/pdfs/BOE-A-2014-1052.pdf.

Boletín Oficial del Estado (2013a), "Real decreto-ley 9/2013", www.boe.es/boe/dias/2013/07/13/pdfs/BOE-A-2013-7705.pdf.

Boletín Oficial del Estado (2013b), "Ley 24/2013", www.boe.es/boe/dias/2013/12/27/pdfs/BOE-A-2013-13645.pdf.

Catalyst Private Equity representatives (2013), Personal communication.

Cereceda, E. (2013), "Mexican energy reform: critical changes on the way", *Electric Power Intelligence Series*, BN Americas, Santiago.

CHPA (Combined Heat and Power Association) representatives (2013), Personal communication.

Ciarreta, A. and C. Gutiérrez-Hita (2009), "Entering renewable energy sources in the Spanish electricity market: The effects of regulatory reforms", International Association for Energy Economics Energy Forum, Third Quarter 2009, pp. 21-23.

Climespace GDF Suez representatives (2013), Personal communication.

Cogen Energía España representatives (2013), Personal communication.

Cogenera México (2013), "Banco de energía", www.cogeneramexico.org.mx/menu.php?m=58.

Cogenera México and Pemex (2013), "Cogeneración eficiente: proyecto de Nuevo Pemex", Green Expo México, Mexico City, 25-27 September 2013.

Cogenera México representatives (2013), Personal communication.

CONUEE (Comisión Nacional para el Uso Eficiente de la Energía) and CRE (Comisión Reguladora de Energía) (2009), "Estudio sobre el potencial de cogeneración en México", www.conuee.gob.mx/work/sites/CONAE/resources/LocalContent/7174/12/Potencial_cogeneracion_resumen.pdf.

Cuttica, J. and C. Haefke (2009), "Combined heat and power: Is it right for your facility?", Midwest CHP Application Center, University of Illinois at Chicago in collaboration with US Department of Energy, www1.eere.energy.gov/manufacturing/pdfs/webcast_2009-0514_chp_in_facilities.pdf.

Davis, S., M. Houdashelt and N. Helme (2012), "Case study: Mexico's renewable energy program", Center for Clean Air Policy (CCAP), http://ccap.org/assets/Case-Study-Mexicos-Renewable-Energy-Program_CCAP_Jan-2012.pdf.

DECC (Department of Energy and Climate Change) (2013), "CHPQA – Quality assurance for combined heat and power", http://chpqa.decc.gov.uk/.

DHC+ Technology Platform (2012), *District Heating and Cooling: A visions towards 2020-2030-2050*, DHC+ Technology Platform, Brussels.

Ecoheatcool (2006), *The European Heat Market*, Ecoheatcool: A Euroheat&Power Initiative, Brussels.

EEC (Energy and Environment Council) (2012), Innovative Strategy for Energy and the Environment, Government of Japan, Tokyo, www.un.org/esa/socdev/egms/docs/2012/greenjobs/enablingenvironment.pdf.

EIA (U.S. Energy Information Administration) (2012), "Country analysis brief: Mexico", www.eia.gov/countries/analysisbriefs/Mexico/Mexico.pdf.

EPA (Environmental Protection Agency) (2013), "Procurement guide: CHP financing" in *CHP Project Development Handbook*, Environmental Protection Agency, Washington, www.epa.gov/chp/documents/chp_handbook.pdf.

EPA (2008), *Technology Characterization: Steam Turbines*, Environmental Protection Agency, Washington, www.epa.gov/chp/documents/catalog_chptech_steam_turbines.pdf.

ETSAP (Energy Technology Systems Analysis Program) (2010a), *Combined Heat and Power: Technology Brief E04*, IEA ETSAP, www.iea-etsap.org/Energy_Technologies/Energy_Supply/Combined_Heat&Power.asp.

ETSAP (2010b), *Gas-Fired Power: Technology Brief E02*, IEA ETSAP, www.iea-etsap.org/Energy_Technologies/Energy_Supply/Gas-Fired_Power_Plants.asp.

EU (European Parliament and the Council) (2012), *Directive of the European Parliament and of the Council of 25 October 2012 on energy efficiency amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC,* Official Journal of the European Union, Brussels, http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:315:0001:0056:EN:PDF.

Euroheat&Power (2013), *District Heating and Cooling: Country by Country Survey 2013,* Euroheat&Power, Brussels.

Fortum representatives (2014), Personal communication.

Heron, C. (2013), "Princess Noura University (PNUW) solar heating system (2013)", Global Solar Thermal Energy Council, http://solarthermalworld.org/content/princess-noura-university-pnuw-solar-heating-system-2013.

InfoPower (2008), "13-MW gas-engine cogeneration plant at DYC distillery in Palazuelos de Eresma (Segovia)", InfoPower Plant Report, March 2008.

IEA (International Energy Agency) (2013), *Electricity Information 2013,* IEA Publishing, Paris.

IEA (2012), *Energy Policies of IEA Countries: The United Kingdom*, IEA Publishing, Paris.

IEA (2011), *Cogeneration and Renewables: Solutions for a low-carbon energy future*, IEA Publishing, Paris.

IEA (2009a), *CHP/DH Country Profile: Russia*, IEA Publishing, Paris.

IEA (2009b), *Energy Policies of IEA Countries: Spain 2009 Review,* IEA Publishing, Paris.

Mairie de Paris (2007), "Le Plan Climat de Paris: plan de lutte contre le réchauffement climatique", www.paris.fr/pratique/energie-plan-climat/le-plan-climat-de-paris/le-plan-climat-de-paris/rub_8413_stand_69591_port_19609.

Millennium Energy Industries representatives (2013), Personal communication.

Ministry of Employment and the Economy (Finland) representatives (2013), Personal communication.

Ministry of New and Renewable Energy (India) (2013), www.mnre.gov.in.

National Grid (2013), "Balancing services: Introduction", www.nationalgrid.com/uk/Electricity/Balancing/services/balanceserv/intro/.

NDRC (National Development and Reform Commission), Ministry of Finance, Ministry of Housing and Urban-Rural Development, National Energy Administration (China) (2011), *Guiding Opinions on the Deployment of Gas-Fired Distributed Energy*, Government of China, Beijing.

Ofgem (Office of Gas and Electricity Markets) (2013a), "Calculating renewable obligation certificates (ROCs)", www.gov.uk/government/uploads/system/uploads/attachment_data/file/211292/ro_banding_levels_2013_17.pdf.

Ofgem (2013b), "The Renewables Obligation", www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/the-renewables-obligation-ro.

Ofgem (2013c), "The Renewable Heat Incentive", www.gov.uk/renewableheatincentive.

Ofgem (2012), "The UK solid and gaseous biomass carbon calculator", www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator.

OECD (Organisation for Economic Co-operation and Development) (2013), *Mexico: Towards a Whole-of-Government Perspective to Regulatory Improvement,* OECD Reviews of Regulatory Reform, OECD Publishing, Paris.

OECD (2004), *Mexico: Progress in Implementing Regulatory Reform*, OECD Reviews of Regulatory Reform, OECD Publishing, Paris.

Pemex representatives (2013), Personal communication.

PlanEnergi Nordjylland representatives (2013), Personal communication.

RWE Innogy representatives (2013), Personal communication.

RWE npower renewables (2013), "Markinch biomass CHP", www.rwe.com/web/cms/en/429434/rwe-innogy/sites/power-from-biomass/united-kingdom/under-construction/markinch-biomass-chp-home/.

The Scottish Government (2009), "Regional Selective Assistance: Grant offers accepted October-December 2008", www.scottish-enterprise.com/~/media/SE/Resources/Documents/PQR/RSA%20Reports/2008-2009-Q3-Awards.pdf.

Sener (Secretaría de Energía) (2009), "Prospectiva del sector eléctrico, 2009-2024", www.sener.gob.mx/res/PE_y_DT/pub/Prospectiva_electricidad%20_2009-2024.pdf.

Singh, M., B. Singh & S.K. Mahla (2013), "Combined heat and power in commercial sector", *International Journal on Emerging Technologies,* Vol. 4/1, pp. 81-87.

SITA UK (2012), "RWE npower renewables and SITA UK sign major deal to supply Scottish state-of-the-art biomass CHP plant", www.sita.co.uk/news-and-views/press-releases/rwe-npower-renewables-and-sita-uk-sign-major-deal.

US (United States Government) (2012), "Executive Order 13624: Accelerating investment in industrial energy efficiency", Federal Register, Washington.

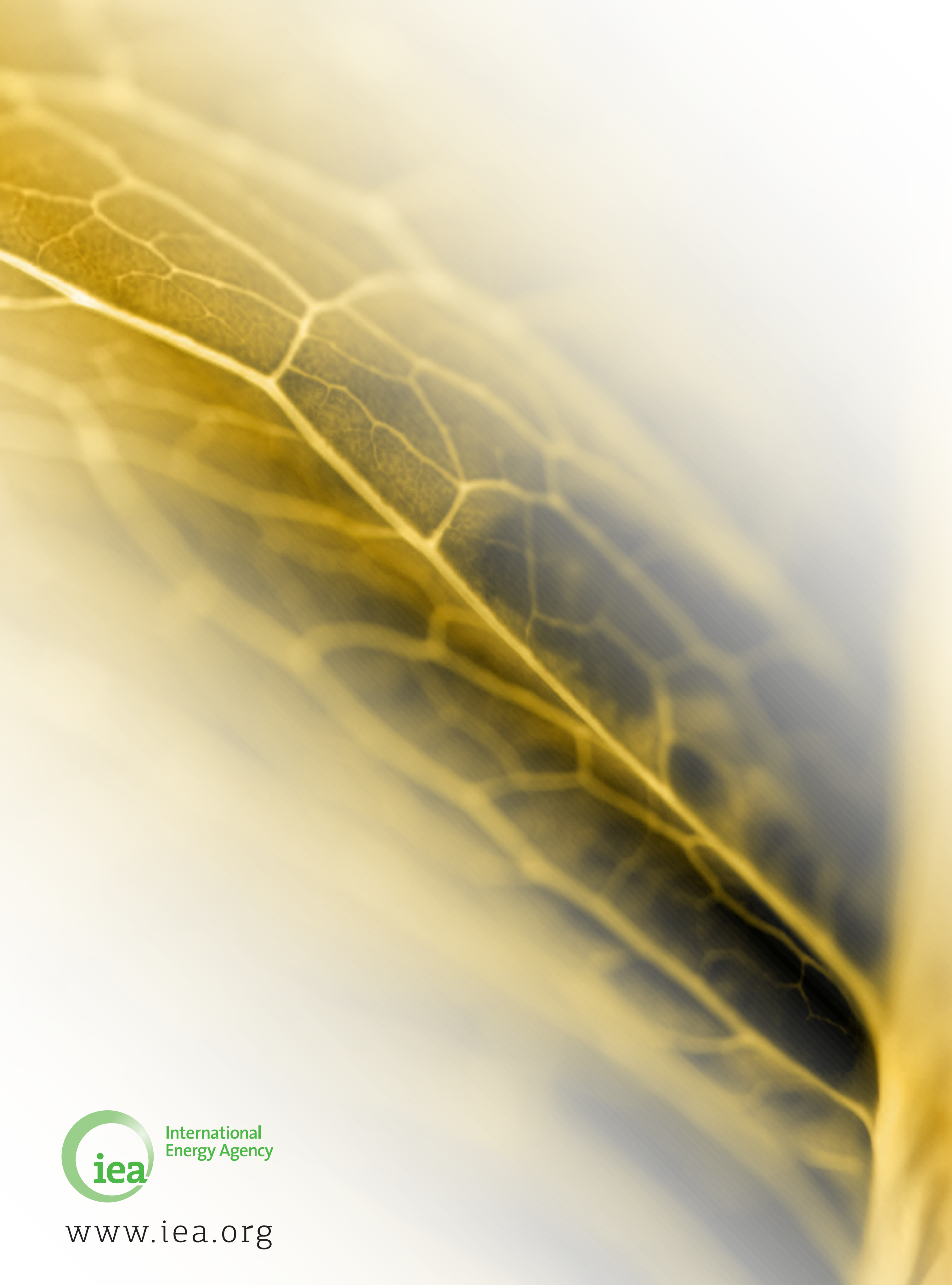
VTT Technology Research Center of Finland representatives (2013), Personal communication.

Wiltshire, R. (2013), "District heating & cooling implementing agreement", BRE Trust, Presented at the IEA District Heating and Cooling Buildings Futures Group, 29 January 2013.

IEA Publications
9, rue de la Fédération, 75739 Paris cedex 15

Typesetted and Printed in France by IEA, April 2014

Cover design: IEA. Photo Credit: ©GraphicObsession



International Energy Agency

www.iea.org