Appendix 1 Overview of RES electricity support mechanisms in the EU

Overview of RES electricity support mechanisms in the EU

EU RENEWABLE ENERGY POLICY

A major part of EU energy policy is the promotion of energy produced from renewable energy sources (RES). RES are naturally renewing energy sources, including bioenergy, solar energy, wind energy, hydropower, and geothermal energy. Electricity produced from RES has seen strong growth in the EU over the past decade, prompted in large part by the legally binding targets contained in the EU Renewable Energy Directive (Directive 2009/28/EC). While there have been decreases in the use of electricity generated from RES, the share of RES in electricity production has nevertheless grown as the consumption of fossil fuels has seen larger decreases[1]. Through the promotion of energy produced from RES, the EU as a whole is on track to meet the targets it has imposed on itself by 2020[2].

In the absence of public intervention, it would have been impossible for the EU to achieve its goals related to the promotion of electricity generated from RES[3]. Consequently, support schemes for electricity generated from RES have formed the backbone of the success of RES electricity penetration in the EU electricity market. To date, most RES are in some way or other still dependant on public intervention from different support schemes[4].

Amongst these the seemingly most successful support scheme is the feed-in tariff (FiT), a policy mechanism aimed at accelerating investment in RES technologies. As explained in further detail below, FiTs require utilities to purchase electricity generated from RES suppliers at a percentage above the prevailing retail price of electricity.

In this context, the EU adopted guidance for the design of RES support schemes for Member States in 2013[3], to ensure that these support schemes do not distort the functioning of the energy market and thereby lead to higher costs for European households and businesses. The Commission guidance suggests that FiTs should be phased out and replaced by support instruments that expose renewable energy producers to market price signals such as feed in premiums. In addition, the Commission considers that schemes should include automatic degressive elements and be complemented by a built-in revision mechanism. Finally, the guidance suggests limiting support to comparable periods (10/15 years) or to a pre-set number of full-load hours calculated based on reasonable expectations for capacity utilisation over a defined period.

---

[1] Eurostat, European Commission, Statistics explained – Energy from renewable sources, February 2016.

[2] European Commission, Report from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions – Renewable energy progress report, June 2015, COM(2015) 293 final.

[3] European Commission, European Commission guidance for the design of renewables support schemes - Accompanying the document: Communication from the Commission Delivering the internal market in electricity and making the most of public intervention, Commission Staff Working Document, November 2013, SWD(2013) 439 final.

[4] Held H et al, Design features of support schemes for renewable electricity, Task 2 report, January 2014.

The present section focuses on the main RES support schemes that have been implemented by the various EU member states. It will briefly first discuss the main RES in the EU and the role of bioenergy therein. It will then provide an overview of and define the main RES electricity support mechanisms in the EU, after which it will discuss certain general issues related to electricity grid balancing, electricity dispatch and grid costs.

RES IN THE EU AND THE ROLE OF BIOENERGY

Over the long term, the primary production of renewable energies has been steadily increasing in the EU. There has been an increase of 174% from 1990 to 2014, with an average annual growth rate of 4.3%. The increase has slowed down, however, with the lowest annual increase of 1.6% being from 2013 to 2014. Only 2002 and 2011, where there were actual decreases, were worse. This is in contrast to the gross electricity generation from RES, which increased by 191% from 1990 to 2014, and by 4.9% from 2013 to 2014, reaching 28% of total gross EU electricity generation in 2014. However, the share of energy from RES in the gross final consumption of energy in the EU amounted to 16% in 2014. Finally, electricity generation from RES contributed 27.5% to the total EU electricity consumption.[1]

The largest share of electricity production from RES in 2014 was hydropower, amounting to 39.99%. This was followed by wind (28.88%), solar (11.22%), solid biomass (9.74%) and all other RES (10.17%). From 1990 solid biomass had the second highest share, until it was replaced by wind power in 2000. Subsequently, in 2013 solar power surpassed solid biomass. However, in 2014 bioenergy (i.e. solid biomass, bioliquids and biogas) was in third place, at around 17%[1].

OVERVIEW OF RES ELECTRICITY SUPPORT MECHANISMS IN THE EU

The development of support schemes for RES electricity is a widely studied subject and several reports and studies have been published in the last few years[5, 6]. Therefore, the aim of this section is not to make a thorough analysis and an in-depth study but to provide the reader with the basic principles of the various support schemes as background information for the rest of the report.

Feed-in Tariffs

Feed-in tariffs (FiTs), are a policy mechanism aimed at accelerating investment in RES technologies by offering long-term purchase agreements for the sale of electricity generated from RES[7]. National laws or regulations regarding FiTs require utilities to purchase electricity generated from RES suppliers at a percentage above the prevailing retail price of electricity. Under this scheme the power plant operator receives a fixed tariff for each unit of electricity generated for a specific time period under specific conditions depending upon, *inter alia*, the location and the technology deployed[8]. Feed-in tariffs thus offer long-term contracts to renewable energy producers, typically based on the cost of generation of each technology. Higher prices are offered for riskier technologies, reflecting production costs that are higher at that point in time.

---

[5] Ragwitz et al, RE-Shaping: Shaping an effective and efficient European renewable energy market, Report compiled within the European research project RE-Shaping, February 2012.

[6] Ragwitz et al, Recent developments of feed-in systems in the EU – A research paper for the International Feed-In Cooperation, January 2012.

[7] International Energy Agency (IEA), Deploying Renewables – Principles for Effective Policies, 2008.

[8] Fouquet et al, European renewable energy policy at crossroads – Focus on electricity support mechanisms, Energy Policy (2008), doi: 10.1016/j.enpol.2008.06.023.

In addition, feed-in-tariffs often include “tariff degression” a mechanism according to which price (or tariff) decreases over time. The goal of feed-in-tariffs is to offer cost-based compensation to renewable energy producers, providing price certainty and long-term contracts that finance renewable energy investments.

The FiT scheme is one of the most commonly used support schemes by most EU Member States, owing to its high effectiveness, primarily by providing plant operators a stable source of income. However, the European Commission in its 2013 guidance paper recommended phasing out FiTs and replacing them by feed-in-premiums and other support schemes[3]. This would enable producers to actively partake by finding a buyer for their electricity generated from RES in the market[4].

Feed-in Premiums

Under a feed-in premium (FIP) scheme, electricity from renewable energy sources (RES) is typically sold on the electricity spot market and RES producers receive a premium on top of the market price of their electricity production. A FIP can either be fixed (i.e. at a constant level independent of market prices) or sliding (i.e. with variable levels depending on the evolution of market prices). A fixed FIP is simpler in design but there is a risk of overcompensation in the case of high market prices and of undercompensating in the case of low market prices. Therefore, a fixed FIP is usually combined with predetermined minimum and maximum levels (“floor” and “cap”) either for the FIP or for the total remuneration (FIP + market price).

A FIP provides an incentive for RES operators to respond to price signals of the electricity market, i.e. to produce electricity when demand is high and/or production from other energy sources is low. It also encourages RES investors to consider expected load patterns in the engineering of the RES project (e.g. choice of site and turbine type for wind parks, orientation of PV modules). A FIP therefore contributes to an increased integration of RES into the electricity market, resulting in a more efficient combination of electricity supply with demand. This is becoming increasingly important with rising shares of renewable energy in electricity generation.

In general, three main types of feed-in premium exist (see Figure 3.1). In the case of a fixed premium, the premium does not depend on the average electricity price in the power market. Thus, the revenue risk when compared to FIT is increased as the renewable generators bear all price risks from the electricity market. Furthermore, from the perspective of providing an optimal support level, over- and under-compensation may occur, meaning that the support level may not be optimal[6]. However, operational decisions can be optimised as producers are exposed to market price signals. Costs are also more predictable with a fixed premium with pre-determined capacity limits[3]. Secondly, a feed-in premium with cap and floor prices reduces revenue risks and surpluses as only a certain income range is allowed under this model. Finally, there is a sliding premium (or "contract for difference"), where the premium is a function of the average electricity price. In this case, the revenue risk does not necessarily increase[6].

Figure 3.1: Different types of feed-in premiums (FIP)[9]

Feed-in systems have been proven to be flexible regarding adjustment to market developments. It is therefore important that they are designed cleverly to support renewables in a cost efficient way. Among others, this can be achieved by implementing stepped tariff design, a regular degression of tariffs, the combination with tendering approaches for large plants or the introduction of growth corridors for more expensive technologies. Feed-in premiums might be helpful to improve the market integration of renewables. Their development needs to be monitored closely in order to identify best practice.

In a FIP system the electricity price is part of the overall remuneration and consequently it provides better market compatibility; however, it involves higher risks for plant operators[4].

The Commission has signalled that it has a preference for FiPs as a RES support scheme, as it considers that FiPs have several advantages compared to other schemes. In particular, according to the Commission it forces RES energy producers to find a seller for their production on the market, ensuring that market signals reach the RES energy producers through varying degrees of market exposure[3].

A variable or floating premium will automatically fall when electricity prices (and carbon prices) go up. From a market perspective it may be considered to have the disadvantage of partly shielding the beneficiary from price signals, but from the investor perspective this may be precisely what allows the investment to take place at a reasonable cost of capital. A fixed premium ignores electricity price movements, which can result in over compensation if prices are higher than forecast (when setting the premium), or in losses if prices are lower. This higher risk may trigger higher capital costs. However, in exposing producers to market price signals it can help optimise operational decisions. A fixed premium with pre-determined capacity limits also has the advantage of costs being more predictable[3].

Auction Schemes

Auction Schemes for RES generally work well when combined with any other forms of support scheme such as FiTs, FiPs, quota obligations, or investment support. Tenders and auctions are used as a competitive allocation mechanism for cost effectively allocating financial support to the RES electricity generation projects. Herein, the design of the tender or the auction is normally based on the market's need for the most competitive bid for a specified source of energy. This form of deployment of a support scheme leads to significant competition between the producers of the RES electricity, thereby exposing the real cost of the technology and leading to efficiency[3, 4].

Auctions can be of two types: price based auctions and multi-criteria auctions. The former is one where price is the only award criterion and the latter is one wherein price is the main award criterion, but with additional criteria in the form of prequalification requirements such as local content requirements, environmental impacts of the RES electricity, impact on local R&D etc. [4].

These auctions/tenders are organized by public authorities who have the responsibility for the preparation of the auction/tender documents such as the *ex ante* calculation of energy costs, publication of the auction, evaluation of the bid and finally selection of the most suitable bid.

---

[9] Rathmann et al, Towards triple-A policies: More renewable energy at lower cost, Report compiled within the European research project RE-Shaping, November 2011.

Tradable Green Certificates

Tradable Green Certificates (TGCs) are certificates that can be sold on a certificate market. This allows RES electricity producers to obtain revenue in addition to the revenue from the sale of the electricity they produce and feed into the grid. There are therefore two streams of revenue that RES electricity producers benefit from, namely the electricity market price and the TGCs' market price.

For every pre-defined unit of electricity produced, TGCs are issued. At the same time, the demand for TGCs is generated through obligations, imposed for instance on electricity distributors[10].

In a situation where there is an imposed demand for renewable electricity (i.e. an obligation) TGCs serve two purposes:

1. they act as an accounting system to verify whether the obligation has been met; and
2. they facilitate trade through the establishment of a separate market for the 'greenness' so that an obligation may be fulfilled by buying TGCs either together with physical electricity or separately.

Other

Quota Obligations are obligations that require energy suppliers to purchase a quota of RES energy (or green certificates representing the production of such energy). TGCs are usually combined with quota obligations, but TGCs can in principle have a wider use. Quota obligations create markets between RES energy producers and energy suppliers, whereby they can trade RES energy or certificates at a price determined by them and other possible market players. As RES energy producers must market and sell the energy on the relevant market, quota obligations expose them to market prices that include a market price for the "greenness" of the RES energy. Despite the benefit of exposing RES energy producers to the efficiency of market prices, a disadvantage for investors is that such schemes generally offer significantly less revenue, especially when there is no minimum price for a TGC[3].

Investment Support is provided by member states on a national level for RES electricity and is often given to power plant generators using less mature technologies such as solar PV. It is coupled with other support measures such as FiTs and FiPs, and is often not the only support mechanism for RES electricity generation. It is generally a one-off measure that does not need to be readjusted at a later stage due to developments in technology or a change in markets in order to avoid overcompensation[4].

Often EU funded instruments such as the European Regional Development Fund (ERDF) etc. also provide investment support in coordination with the various national level support schemes in member states[3].

Tax Exemptions or Incentives are often used in addition to other kinds of RES electricity support schemes that are targeted at specific kinds of technologies used to generate RES electricity. These are provided by way of tax incentives relating to investments such as income tax deductions, by providing credits for the investment made in renewable energy or accelerated depreciation etc., or by providing production tax incentives that lower the operational costs[4].

---

[10] Mir-Artigues et al, The Economics and Policy of Solar Photovoltaic Generation, Switzerland, 2016.

Low Interest Loans are provided to power plant generators producing RES electricity at interest rates lower than those available in the market or by way of providing other concessions such as longer repayment periods or interest holidays etc. These have again been given in addition to other RES support schemes to reduce investment costs[4].

RESPONSIBILITY FOR ELECTRICITY GRID BALANCING

Originally, most existing electricity grid infrastructure and wholesale markets had been designed to accommodate centralised and dispatchable national power output from conventional thermal and hydroelectric plants. As indicated above, the support schemes have been successful in increasing the uptake of energy produced from RES. As a result, today it is mostly variable RES energy such as wind and solar that constitutes the new capacity coming online in the EU[3].

Balancing obligations were at first not imposed on wind and solar, as the producers of electricity generated from such RES only constituted a small share of the market and market structures could furthermore not support such obligations at low cost. However, the system architecture is starting to become more flexible in a number of ways, with the growth in the share of wind and solar and the evolution of technology and the markets. According to the Commission, a broader allocation of balancing responsibilities is therefore becoming feasible[3].

It is difficult for RES such as wind and solar to be easily "dispatchable", as they have very short high probability time frames whereby their power output can be predicted. This can be done with close to full certainty for two hours ahead, but the margin of error rises especially beyond 24 hours. In order to avoid turning to conventional power plants to meet demand patterns in any time period, certain other RES can be easily dispatched, one of the most efficient appearing to be biomass[3].

In order to facilitate market access in the EU, electricity produced from RES has been granted priority dispatch rights. By insulating RES electricity from volume risk, it is easier for new market players and technologies to enter markets that are dominated by incumbent centralised large power producers. Furthermore, as RES electricity producers should not be penalised for infrastructure inadequacies and as they should be protected from possible anti-competitive behaviour of imperfectly unbundled transmission system operators (TSOs), the interdiction of significant curtailment of RES electricity was introduced[3].

Finally, cost transparency and non-discriminatory rules for all generators that access and connect to the power grid is essential. It is therefore important to be more consistent in the manner in which grid connection fees and network tariffs are charged[3].

EXISTING NORMATIVES REGULATING GRID ACCESS AND DISPATCH OF RENEWABLE POWER

2020 Climate & Energy Package

The European Union implements its strategies and drives the future development of EU society for a smart and sustainable growth through Directives. The 2020 climate & energy package defined a series of binding climate and energy targets:

- 20% cut in greenhouse gas emissions (from 1990 levels)
- 20% of EU energy from renewables
- 20% improvement in energy efficiency (EE Directive – 2012/27/EU)

Among others, the climate-energy package, defined the following measures:

i. Review of the Emission Trading System based on the exchange of greenhouse gas emission shares;

ii. Promotion of the Effort sharing outside the EU-ETS system, for the reduction of GHG emissions for those sectors not covered by the Emission Trading System (such as housing, agriculture, waste, transport excluding aviation)

iii. Promotion of the Carbon Capture and Storage (CCS) Mechanism to fix atmospheric carbon into geological reservoirs.

Member States transposed these regulations, by introducing specific targets (varying for each Member State) to reflect the national context regarding the production of energy from renewable sources and the planned capacity for further growth.

The Renewable Energy Directive - 2009/28/EC

The Renewable Energy Directive (RED) aims at the promotion of energy from renewable energy sources: guidelines for dispatching renewable electricity are also given.

RED regulates the transmission and distribution of electricity produced from renewable energy sources through the Member States, that have to ensure a priority or guaranteed access to the grid system based on transparent and non-discriminatory criteria (Article 16).

In order to ensure grid access, Member States must take appropriate measures to ensure adequate network infrastructure and to avoid market operational problems, so as to minimize the reduction of electricity produced from renewable sources: in order to prevent inappropriate curtailments the responsible system operator has to indicate corrective measures to be taken.

In terms of dispatching to the system, Member States shall require system operators to ensure that installations dispatching renewable energy electricity to the system have priority over other installations. Similarly, Member States may also require the system operator to give priority when dispatching generating installations producing combined heat and power. At the same time Transmission System Operators (TSOs) have to ensure the reliability and safety of the grid, making the priority subject to the secure operation of the national electricity system, as described by the Internal Electricity Market Directive.

The Internal Electricity Market Directive – 2009/72/EC

The EU issued the Internal Electricity Market Directive (IED) in order to redefine the rules and measures of the electricity market to guarantee fair competition and appropriate consumer protection, introducing common rules for the generation, transmission, distribution and supply of electricity on the Internal Market. It establishes rules and guidelines related to the organization and functioning of the electricity sector.

In particular, Article 15 of this Directive is linked to Article 16 of the RED, requiring that System Operators have to give priority access to systems generating renewable electricity and may do the same for CHP installations. The article also stated that - in case of need related to the security of supply - a Member State can give dispatch priority to generating installations using indigenous primary energy fuel sources, to an extent not exceeding, in any calendar year, 15 % of the overall primary energy necessary to produce the electricity consumed in the Member State concerned. It is important to note that the term indigenous resource differs for each country, on the basis of the availability of the source in its specific area.

When dispatching generating installations using renewable energy sources, TSOs shall follow the

rules laid down by the Renewable Energy Directive, subject to the guarantee of the system security.

The Energy Efficiency Directive - 2012/27/EU

The Energy Efficiency Directive (EED) aims at increasing energy efficiency through the establishment of a framework for promotion and development of systems producing combined heat and power (cogeneration).

In terms of rules on transmission, distribution, access and dispatch to the grid, the Energy Efficiency Directive directly refers to the rules laid down in the RED and the IED. Furthermore, EED implements the IED (Directive 2009/72/CE) stating that Member States must ensure that energy efficiency criteria are applied, by energy regulatory authorities, in relation to the operation of the electricity infrastructure. This concerns, in particular, transmission, distribution, load management and connection to energy generating installations (including micro energy generators).

Moreover, the EED Directive integrates both Article 16 of the RED and Article 15 of Directive 2009/72/EC, stating that transmission system operators and distribution system operators who are in charge of dispatching the generating installations in their territory, have to:

a. guarantee the transmission and distribution of electricity from high-efficiency cogeneration;

b. provide priority or guaranteed access to the grid of electricity from high-efficiency cogeneration;

c. when dispatching electricity generating installations, provide priority dispatch of electricity from high-efficiency cogeneration in so far as the secure operation of the national electricity system permits.

Member States shall in any case ensure that priority access or dispatch for energy from variable renewable energy sources is not hampered.

The Directive also encourages Member States to promote the use of electricity produced from high-efficiency cogeneration from small scale and micro-cogeneration units, by facilitating the connection to the grid and simplifying authorization procedures for individual citizens and installers (Article 15).

Comparing it with RED, both Directives give priority or guaranteed access and priority dispatch (maintaining the stability of the system) to electricity produced in cogeneration plants (EED) or from renewable sources. As cogeneration plants are often driven by heat demand, these systems may prevail over renewable energy plant, thus meaning that electricity produced by cogeneration systems have first priority.

In the context of providing balancing services and other operational services at the level of transmission system operators or distribution system operators, high efficiency cogeneration operators can enter the market with their offer, where it is technically and economically feasible. Transmission system operators and distribution system operators shall ensure that such services are part of a transparent, non-discriminatory and open to scrutiny services bidding process (Article 16). To encourage high-efficiency cogeneration systems, Member States may require the operators to be sited close to areas of demand, so as to reduce the connection and use of system charges.

The Directive also states that the access and participation of demand response in balancing services (reserve and other system services market) for these types of systems has to be promoted, defining the technical modalities on the basis of the technical requirements of these markets and the capabilities of demand response (Article 15).

Remarks

- To facilitate deployment and market penetration, renewable energy has been granted priority dispatch rights, under Directive 2009/28/EC. This helps new technologies and market players to enter the market which is dominated by centralised large power producers.

- Separate from priority of dispatch, the interdiction of significant curtailment of renewable energy contained in Directive 2009/28/EC was introduced to ensure that renewable energy producers should not be penalised for infrastructure inadequacies as well as to protect them from possible non-competitive behaviour of imperfectly unbundled TSOs.

- The "volatile" nature of some renewable energy sources may represent an obstacle to ensuring system security, thus resulting in rejection by system operators. This can represent a barrier to renewable energy producers, who need to sell their production and who, for project financing, need the guarantee of a stable income.

- It is important to have cost transparency for all generators accessing and connecting to the power grid, and non-discriminatory rules are foreseen by the Directives. Increasing consistency in the way that Member States charge both grid connection fees and network tariffs is important for creating an effective internal electricity market.

- In the case of competitive allocation mechanisms, cost calculation can serve as a reference for policy makers or as a benchmark for technology-staggered auction processes. Cost calculation involves a number of distinctive steps: starting with the selection of cost parameters and cost calculation methodology, followed by setting the cost and revenue projections, and finally transferring the levelised cost of electricity (hereinafter: LCOE)[11] into an actual support level. All these steps show differences between the methodologies across Member States. This is partly due to different support instruments that entail different methodological requirements. In a first step, the large majority of Member States apply an approach based on project-related costs, rather than avoided costs or societal benefits. The cost parameters used vary across Member States (e.g. in the way market and network integration costs are considered). Where similar project cost calculations or estimates of the LCOE are used by Member States, these are not a major source of differences in support levels between them. Ideally, if all systems were to apply the same equation for LCOE and the same input parameters, this would make systems more comparable.

- The European Union's Directive currently does not allow grid operators to manage energy storage to any significant extent, but the benefits for markets and society to be derived

[11] LCOE (levelized cost of energy) is one of the utility industry's primary metrics for the cost of electricity produced by a generator. It is calculated by accounting for all of a system's expected lifetime costs (including construction, financing, fuel, maintenance, taxes, insurance and incentives), which are then divided by the system's lifetime expected power output (kWh). All cost and benefit estimates are adjusted for inflation and discounted to account for the time-value of money. As a financial tool, LCOE is very valuable for the comparison of various generation options. A relatively low LCOE means that electricity is being produced at a low cost, with higher likely returns for the investor. If the cost for a renewable technology is as low as current traditional costs, it is said to have reached "Grid Parity".

from energy storage facilities can justify policy intervention. Indeed with the use of storage systems the stability of supply will be enhanced. Biomass, by its nature, could play an effective role in this.

BIOFUELS/BIOLIQUIDS MARKET FRAMEWORK

Fossil energy carriers dominate the transport sector that accounts for about a quarter of EU greenhouse gas emissions. Within the transport sector, road transport consumption accounts for approximately 80% (81.7%), while only 5% refers to alternative fuel (90% of which are biofuels).

The market for transport fuels, as well as that for bioliquids for stationary power generation, grew steadily until 2012. A turnaround was then observed in the period 2012-2014: 14.6 Mtoe of biofuels were consumed in 2012, against the 13.9 Mtoe consumed in 2014. This is probably related to the uncertainty created among investors by regulatory changes that no longer guaranteed a stable economic framework for investments in this sector[12].

The decrease (as reported in Fig.1) shown by biofuel consumption is related, in part, to policy-related matters (e.g. ILUC) and to the decrease of fossil fuel consumption (gasoline and diesel) in the EU-28. Indeed, since 2009 it is possible to observe a downward trend for oil products demand:

- Overall demand has declined by 8%
- Gasoline demand has declined by 17%
- Diesel demand has declined by 3%

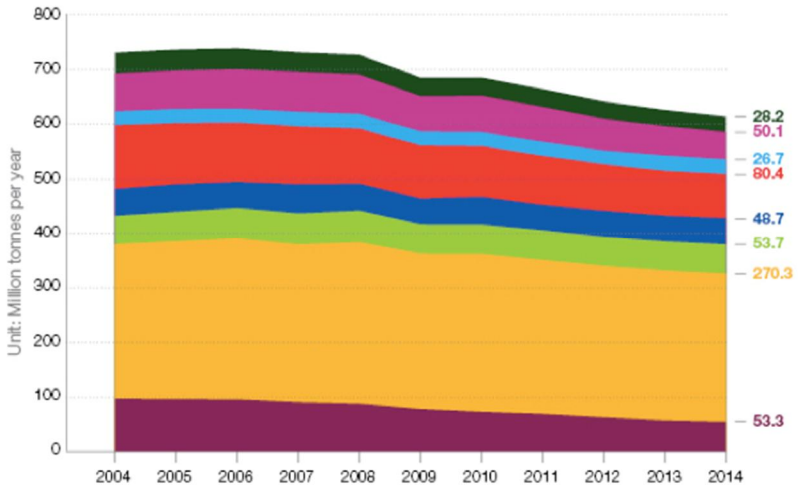


Figure 1 Demand history of oil products in the EU[13]

[12] EBTP. (2016). Draft Strategic Research and Innovation Agenda 2016. European Biofuels Technology Platform. Available at: http://biofuelstp.eu/consultation/2016_03_21_Final_Draft_public_consultation.pdf

[13] FuelsEurope. https://www.fuelseurope.eu/dataroom.

However the production of biofuels has not been affected by the same decline, except for a drop in 2011. Therefore, the European regulations on biofuel's importation, have had a positive effect on internal production and, consequently, on export as shown in Figure 1.

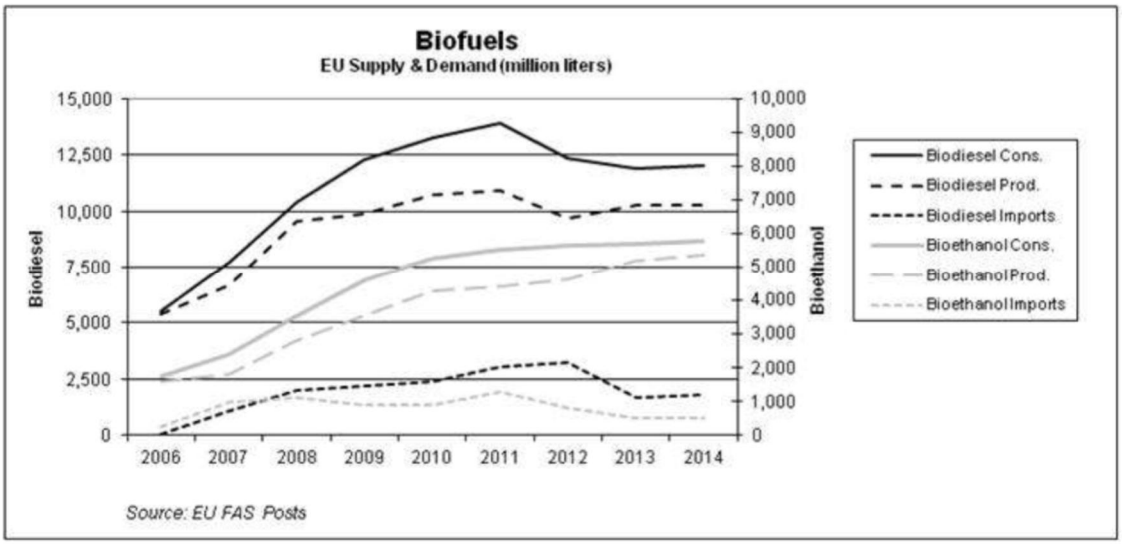


Figure 1 European Biofuels supply and demand in the years 2006-2014[14]

As regards bioliquids for stationary power generation, the scenario is not so different in relation to the sources utilized for producing energy: in 2014, fossil fuels continued to be the major contributor to net electricity production in the EU-28. Combustible fuels accounted for nearly one half (49.8%) of total net electricity generated (Eurostat).

Existing legislation regulating the biofuels/bio liquids sector

The Fuel Quality Directive (FQD) and the Renewable Energy Directive (RED) define EU biofuel/bio liquid policy. While the FQD sets a 6% target for GHG emission reduction from the European fuel mix by 2020 in comparison to 2010, the RED requires that EU Member States ensure 10% renewable energy in transport in 2020, formulated as follow:

10% = [*ALL* Renewable Energy in *ALL* forms] / [Petrol, Diesel, Biofuels, Bioelectricity]

This target is measured against the use of fuel in road transport (denominator), but can be fulfilled by any renewable energy in any form of transport (numerator).

In the framework of the amendment proposals of the RED and FQD Directives, the ILUC Directive (adopted in September 2015) sets a 7% limit on biofuels from crops and a target for advanced biofuels at 0,5% (energy content) for 2020.

The Renewable Energy Directive

The Directive establishes a 10% target for energy in road transport coming from renewable

[14] EBTP. (2016). Draft Strategic Research and Innovation Agenda 2016. European Biofuels Technology Platform. Available at: http://biofuelstp.eu/consultation/2016_03_21_Final_Draft_public_consultation.pdf

sources in each of the member states by 2020. Renewable energy in road transport is often referred to as biofuels, even if it also includes other energy carriers such as hydrogen or electricity from renewable sources.

RED also defines the sustainability criteria for both biofuels and bio liquids:

- Based on life cycle analysis, until 2017 the use of “eligible biofuels”, according to the sustainability criteria reported in Annex V of the Directive, should result in a GHG savings of at least 35% compared to fossil fuels. From 2017, the reduction has to be 50%, and at least 60% for new plants.

- Different feedstock have different reference values for meeting the required sustainability, and feedstock cultivation on land with high biodiversity value such as primary forests and highly biodiverse grasslands, or land with high carbon stocks such as wetlands, peatland or continuously forested areas is not accepted.

- Second-generation biofuels receive double credit: this means that biofuels made from lignocellulosic, non-food cellulosic, waste and residue materials will count double towards the goal. Calculations are made on an energy basis.

- The Directive gives a bonus of 29 g CO2/MJ to biofuels produced with feedstock grown in degraded/contaminated land.

Each member state is required to ensure the application in its territory of the biofuel Sustainability Criteria to biofuels produced in the EU and those imported. This is ensured by certification schemes recognized by the European Commission.

The Fuel Quality Directive

The FQD requires that all fuel suppliers (oil companies) have to reduce GHG emissions by 6% by 2020, taking into consideration all fuel categories supplied to the market. This is consistent with the 10% use of biofuels, and the aim of shifting the demand towards sustainable biofuels with higher GHG savings. The means to achieve this goal are blending mandates and standards for a defined set of fuel parameters. The blending volumes for biofuels are shown below:

- 10% ethanol in gasoline (E10) except for old cars (E5) that can benefit from a transitory regulation.

- 7% biodiesel (B7) by volume.

The ILUC Directive

The ILUC (Indirect Land Use Change) Directive was approved on April 28, 2015, following a long debate on the revision of the RED and FQD Directives. The new Directive further defines the way in which Member States can meet the 10% target for renewables in the transport sector by 2020. Generally it defines the "weight" with which the contribution of biofuels produced from different feedstock has to be considered, having put a cap of 7% on the contribution of biofuels produced from conventional crops, the so called first generation biofuels, recognised by the RED and a greater weight on advanced biofuels, produced from a list of suitable feedstocks.

In the approved Directive, no ILUC factors are included due to the lack of scientific conclusiveness or general agreement nor are there mandatory target for advanced biofuels (there is only an indicative reference value at 0,5% as a sub-target). However, in order to reduce the risk of indirect land use change, a number of additional reporting obligations are required for the fuel

providers. Advanced biofuels are those made from feedstocks listed in Annex IX part A1 of the ILUC Directive.

The 3% that remains to meet the overall goal of 10% by 2020, can come from a variety of multiple counted biofuels, as it is shown in Table 1:

Table 1 European biofuel policy development towards 2020 and beyond[15]

	The ILUC Directive
Cap	7% food-crop based (energy content)
Sub-Targets	Non legally binding sub-targets of 0,5% advanced biofuels (excl. UCO/TME)
Multiple Counting	2x non-food cellulosic material; ligno-cellulosic material, including UCO and animal fats 2,5x RES_E in non-road 5x RES_E in road transport
ILUC Factors	Reporting for information purpose in FQD and RED, including a range. December 2017: review of both, effectiveness of measures and best available science on ILUC factors

Member States have to transpose the directive into national legislation by mid-2017, and establish the level of their national indicative sub-targets for advanced biofuels to the end 2016 - beginning 2017.

Remarks

- The Energy Union stresses that the EU needs to invest in advanced, sustainable alternative fuels, including biofuel production processes, and more generally in the bio-economy. The integrated SET-Plan aims to accelerate the development and deployment of low-carbon technologies.
- The complexity of the biofuels issues is not yet fully understood by the public so it would be worthwhile to encourage and support initiatives to inform and explain the benefits and

[15] Baltause. (2014). EU biofuel policy developments towards 2020 and beyond. Available at: http//www.core-jetfuel.eu/Shared%20Documents/Ruta_Baltause_EU_biofuel_policy.pdf

necessity of sustainable biofuels to the wider public.

- Establishing a clear, stable policy framework for the long term (post-2020), starting with simple, meaningful, quantifiable objectives and measures would support market development

- The Renewable Energy Directive defining the feedstock established that CO2 is not a feedstock and therefore CO2 has no CO2 footprint

- The Directorate-General for Climate Action should set a default value for e-fuels by the end of 2017

Appendix 2 Review of technologies for bioenergy in balancing grid and providing storage options

THE EXISTING BIOENERGY ASSETS AND THEIR ABILITY FOR GRID BALANCING

The use of biomass in pulverised fuel (PF) boilers.

There are over 1,400 coal-fired power plants[16] reported[17] to have a total capacity of 1,900 GW in 2016. Coal produced over 41% of the world's electricity[18] in 2014.

In Europe there are over 250 coal-fired power plant sites (Figure 2). Some of these sites host fairly small single-unit plants and are used for residential or industrial cogeneration of power and heat or steam. The capacity range per unit is from <100 MWe to up to > 1,000 MWe. Others sites host several (2-6 or more) thermal power plants units co-located on the site and add up to a significant capacity from say 200 MWe to 1,000- 2,000 MWe with the largest complex being over 4,000 MWe.

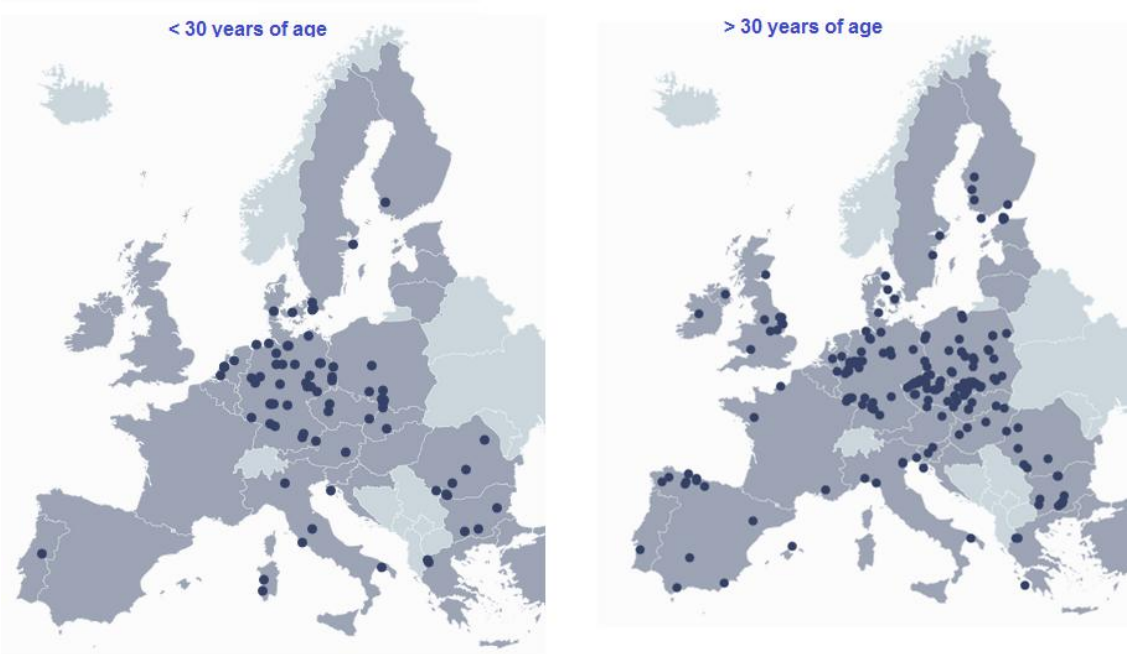


Figure 2 The location and age bands of EU coal-fired power plants[19]

[16] http://globalenergyobservatory.org/

[17] Boom and Bust 2016. TRACKING THE GLOBAL COAL PLANT PIPELINE. COALSWARM / SIERRA CLUB / GREENPEACE REPORT | MARCH 2016

[18] Emissions Reduction through Upgrade of Coal-Fired Power Plants. IEA 2014.

[19] http://www.coalmap.eu

The thermal efficiency at full load of such units operating on hard coal ranges from just over 30 % for small and old units with sub-critical steam conditions up to 48 % for large modern plants using ultra-supercritical steam cycles[20]. If lignite is used, the efficiency is 3-4% lower than for hard coal at comparable conditions.

One should note that there is a variation in the base efficiency of plants, relative to the numbers above. A study[21] indicated that as an average of the boiler population in each of the countries studied, the range in efficiency was between 27 % in India, to Australia in the low thirties, the USA, Korea and China in the mid-thirties, Germany and the UK the high thirties, the Nordic countries (Denmark) and Japan at approximately 40 % and a few plants in France at 43 %.

There is also an age issue where many of the installations are old, e.g. the plants in Belgium, the only plant in Ireland and all ten operating plants in the UK are all 30 years or more.

Nevertheless, the age of coal has not quite passed as there are still new plants being constructed in the EU. Since 2014, about a dozen new power plants have been or will be taken into operation, in Germany and the Netherlands[22, 23]. This often leads to the decommissioning of older units and to an increase in the average efficiency of the portfolio of plants. However, the current situation in the power market, and in some cases lengthy court procedures for permits, makes further expansion unlikely in the near future in Western Europe. Further east, countries like Poland, the Czech Republic and Bulgaria are still looking at expansion and reinvesting in coal and lignite power plants.

To the west, the UK has decided to phase out all remaining coal firing in power plants by 2025[24]. In Spain subsidies for the power plants firing Spanish coal (approx. 1/3 of the overall capacity) was ended in 2014, and the impacts from this are expected to show in the futureError! Bookmark not defined..

Elsewhere the situation is different. In the Asia-Pacific region there is a need for 275 GW of new coal power capacity within the next few years22 and there has been a massive addition to the coal power portfolio in recent decades.

Coal fired plants have typically been operated in base load or upper mid-load regimes, i.e. with capacity factors above 40-50 % and often much higher, and this is still the situation in many parts of the world where power demand is increasing rapidly even if some saturation effects are also noticeable Figure 3.

---

[20] Baseline Efficiency Analysis of Fossil Fuel Power Plants. Economic Commission for Europe. Committee on Sustainable Energy. CEP-11/2015/INF.4 Version 1, 9 October 2015

[21] International comparison of fossil power efficiency and CO2 intensity -Update 2014. Ecofys 2014.

[22] Thermal Power Generation in 2030: Added Value for EU Energy Policy. M. Farley EPPSA. All Energy 2015, Glasgow UK.

[23] Outlook for new coal-fired power stations in Germany, the Netherlands and Spain. Pöyry for UK DECC, 2013

[24] http://www.bbc.com/news/business-34851718

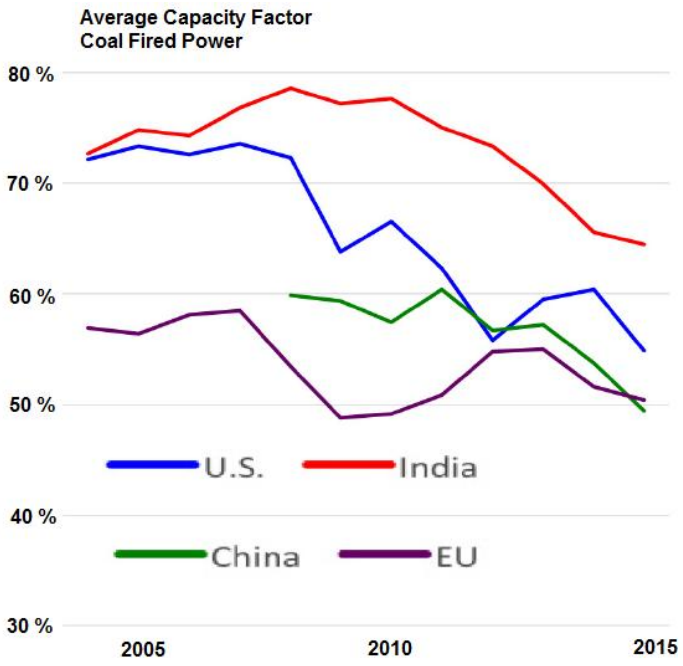


Figure 3 Coal Thermal Power Plant Average Utilization[17]

In Europe, the competition from renewable sources is strongly affecting the outlook for both existing and any possible new coal power plants as renewable energy drives the marginal power price down by reducing the capacity required. At the same time, various other cost drivers in coal-fired power plant increase the cost of generation e.g. new emission control requirements and the cost of emission allowances. As a result some plants can still offer base-load power at acceptable prices, in particular if lignite is used. Others have seen their capacity factor being reduced from base load to mid range.

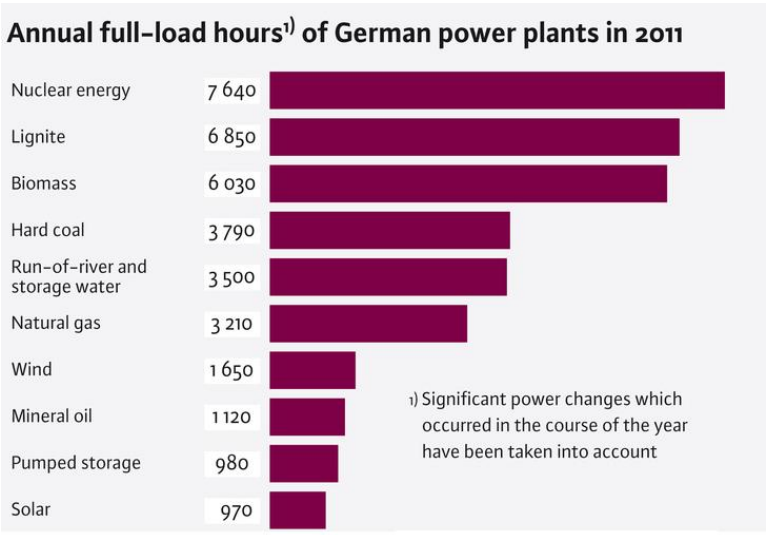


Figure 4 Annual full-load operating hours in German power plants 2011[25]

Figure 4, reflecting the situation in Germany, shows that lignite fired power plants had a capacity factor of 78 % in 2011, whereas hard coal had a capacity factor of only 43 %. Figures[26] from 2014 indicate that lignite generation has maintained its capacity factor whereas the capacity factor for hard coal has reduced by some 5 % since 2011.

In the UK, the installed coal-fired capacity in 2015 was 20 GW[27] while the capacity utilization has ranged from 40 to 60 % in the most recent five years for which statistics are readily available.

In the Netherlands, the situation was different. The coal fired capacity[27] was approx. 7 GW in 2015 (being reduced to 5.8 GW in the beginning of 2016), and the generation from coal was 45 TWh, i.e. an average capacity factor of 73 %. The reason for this high capacity factor, in spite of an increase in renewable energy, is that natural gas fired power plant capacity was utilized at a very low rate such that the base load mainly consisted of nuclear and coal-firing.

In Denmark the installed capacity in central, coal fired power plants was 4.8 GW in 2014, while the production from these was 12 TWh, i.e. an average capacity factor of only 30 %. This low utilization is also related to the plans to decommission some of these power plants, or alternatively convert them to biomass.

This is indicative of coal fired plants no longer being continuously operated but instead often operating to various schedules. In Germany, weekly scheduling is common, i.e. continuous operation from Monday morning to Friday night. In the UK, one common scheduling scheme is two-shift, i.e. operation at high load from 06:00-10:00 and from 16:00-22:00 hours every day, and at some intermediate load between 10:00-16:00 hours, while not operating between 21:00-06:00 hours, this scheme being applied for 5 or 7 days each week. The effect of such schemes is that the capacity factor is reduced to the range given above, i.e. to 40-60 %.

Furthermore, such scheduling means that the number of start-ups is increased relative to base load plant that ideally has only one start-up per operating period between over-hauls. Weekly scheduling means 50 starts and daily scheduling by two shifts means over 300 starts per year. These stop and start sequences each take their toll on the lifetime of the plant, while the efficiency and the maintenance needs to an extent were in many case not anticipated in the design.

Technical characteristics of PF boilers

The characteristics of coal fired power plant are shown in Table 2. It takes several hours to start up a coal-fired power plant depending on the time it has been off-line, as heat can be retained in the boiler system for a short period, e.g. overnight. The start-up typically proceeds via adjustment of the boiler water circuits and initiation of auxiliary fuel burners prior to starting one coal mill and

---

[25] Source BDEW, Germany https://www.bdew.de/internet.nsf/res/EM_2012E_S_13.jpg/$file/EM_2012E_S_13_std.jpg

[26] Stromerzeugung aus Solar- und Windenergie im Jahr 2014. Bruno Burger Fraunhofer-Institut für Solare Energiesysteme ISE Freiburg, den 07.01.2015

[27] Renewable Energy in The Netherlands December 2015. M Visser. Hanze University of Applied Sciences Groningen

burner to raise the steam pressure. The steam produced is drained or routed to the condenser via the by-pass while some is flushed through the steam turbine to pre-heat it. When minimum load pressure and temperatures are reached, the turbine can be synchronized with the grid. From then on, more mill and burners are brought into operation, the flue gas desulfurization plant is brought on-line and, when a defined stable generation point is reached, the auxiliary burners are shut down and the plant is ramped up to the desired load.

The time for heating the high pressure parts of the boiler and the steam turbine is limiting as a heat rate that is too high for either of these results in a decrease of their service life. For the same reasons the plant needs a minimum operating time prior to shut-down, and also a controlled shut-down, as well as a minimum stop time before restarting.

Table 2 Coal-fired power plant characteristics[22, 28, 29, 30, 31]

	Hard coal			Lignite		
Operating sequences time duration	New, optimized	State of the art plant	Typical plant	New, optimized	State of the art plant	Typical plant
Hot (<8 hrs off), hrs	2	2.5	3	2	4	6
Cold, >(48 hrs off), hrs	4	5	10	6	8	10
Min. op. time, hrs		4			6	
Shut-down time to hot			0.5-1.5			
Time to restart, hrs		2			6	
Performance characteristics	New optimized	State of the art plant	Typical plant	New, optimized	State of the art plant	Typical plant
Efficiency, full load, %		48			44	
Efficiency, min. load, %		40			41	
Minimum load, %	20	25	40	40	50	60
Ramp range load, %		40-90			50-90	
Load ramp rate, %/min	6 or more	4	1.5	4	2.5	1
Prim. frequency control	10 %/ 10 s	2-5 %/30 s		10 %/ 10 s	2-5 %/30 s	

The thermal efficiency at full load of coal fired power plants ranges from just over 30 % for small and old units, to units with sub-critical steam cycles that can reach 40 %, up to super-critical and ultra-supercritical steam cycles that can achieve 44 % and 48 %, respectively20, using hard coal.

[28] Erneuerbare Energie braucht flexible Kraftwerke – Szenarien bis 2020. VDE

[29] Technical Assessment of the Operation of Coal & Gas Fired Plants. Parsons Brinckerhoff DECC. 286861A. Dec. 2014

[30] Fossil befeuerte Großkraftwerke in Deutschland, Stand, Tendenzen, Schlussfolgerungen. VDI Dezember 2013

[31] Increasing the flexibility of coal-fired power plants. Colin Henderson. IEA Clean Coal Centre September 2014

These more advanced technologies are applied at larger scale only and in the most modern plants. If lignite is used, the efficiency is 3-4% lower.

The plant can operate in a stable manner from the minimum load to the maximum load, and sometimes there is also some margin for a small short-term overload, or else the capacity can be used up to 94-98 % to allow for rapid changes, i.e. primary frequency control.

The minimum load is very much related to the plant design. In the past when plants were generally designed for base-load, the minimum stable load was not a design consideration. Plants would be designed to include several mills, e.g. 5 or 6 mills for a 500 MWe plant, and at the minimum load without auxiliary fuel firing, the majority of the mills were required to be in operation at their maximum turn-down for stable firing, i.e. resulting in a minimum load of approximately 40 %.

When new boilers are designed, both the number of burners in the boiler, and the turn-down of each burner as well as burner tilting can be optimized to reach a significantly better turn-down ratio, and minimum loads of 20-25 % can be sustained. In Germany, the use of indirect firing has been tried. In this case, some of the coal powder from the mill is diverted to a storage bunker, such that the burner can operate at lower load than the mill minimum load, and a minimum load as low as 10 % can be achieved.

However, since the steam flow and steam conditions are affected at such low loads, the turbine efficiency drops quite considerably, some 10-20 % relative to the nominal efficiency, where the higher figure represents a higher turn-down ratio. As mentioned earlier, the average plant efficiency for all PF power plants in a country can vary from the mid thirties to over 40 % in Europe.

The rate of increase in load output is of the order of several % load change per minute, but only within the control range of the boiler, which is typically 40-90 % of the load. So, to come from 40 % load to 90 % load (or vice-versa) would take 10-20 minutes.

For comparison, most power plants using a steam turbine (nuclear, thermal combined cycle) have a similar magnitude of ramping (BWR), whereas single cycle gas turbines have ramp rates from 0-100 % in 5 minutes and hydropower plants can achieve the same within a couple of minutes.

TSOs typically define the criteria[32],[33] for different types of power plants that are connected to their grids, such as ramp rate and operating load range, potential for island operation, ability to sustain voltage and frequency deviations, control of reactive power etc. These typically also include a primary frequency control adjustment within a time frame of less than one minute. However, such rapid changes are effected by the accumulated energy e.g. steam volumes in the system before the main control of the turbine and boiler can adjust the firing rate.

Use of bio-energy in PF boilers

The use of biomass in PF boilers designed for coal ranges from a few percent to an increasing

---

[32] Affärsverket svenska kraftnäts föreskrifter och allmänna råd om driftsäkerhetsteknisk utformning av produktionsanläggningar. SvKFS 2005:2

[33] Technical Regulation for Thermal Power Station Units of 1.5 MW and higher. Regulation for grid connection TF 3.2.3 Version 5.1, Energinet.dk, 1 October 2008.

share of biomass by co-combustion (*aka* co-firing), to complete conversion of the boiler to 100 % biomass firing.

There are three main methods for using biomass[34, 35, 36];

- direct co-firing where the solid biomass is introduced into the boiler furnace together with coal (pre-mixing) or by separate burners
- in-direct co-firing where the solid fuel is first gasified, the gas cleaned to some extent from particulates of ash and other substances, and the gas then fired into the boiler furnace together with coal
- parallel co-firing where two separate boiler furnaces are fired with coal and biomass, respectively, and the produced steam or pre-heated water is fed to a common integrated steam system.

Direct-co-firing can in turn be divided into three types. Pre-mixing systems blend coal and biomass fuel and feed the blend into the coal mills and then to the coal burners in the boiler. This type of firing is suitable for clean, dry and hard, millable materials such as wood, olive pits, nut shells, wood pellets etc. Due to energy and volume limitations and to avoid issues with devolitilization of the biomass in the coal mill, the biomass blend fraction rate is below 10 % on an energy basis, and typically 5-8 %. Due to the low cost, only handling storage and conveying equipment for biomass is required, while old equipment is mainly used with only minor modifications.

The second type is separate milling and pre-mixing. In this case both fuels are milled separately and then the biomass is fed into the coal injection line at the outlet of the coal mill or at the burner end. In this way there is a possibility to fire more biomass in the mixture, up to 50 % of the heat input. There is a possibility to use a wider range of biomass in this case, as the biomass mill can be optimized for the feed. However, again the biomass should be dry and millable and preferably relatively clean in terms of ash, sulphur and chloride content. Because of the quantities involved, there is a preference for pelletized material as this is available in bulk quantities with consistent properties.

The third type, which is less common, is to install a separate biomass milling and burner system in parallel with the coal system. This design variety has also been used for sewage sludge injection.

Depending on the biomass fuel and the boiler characteristics, the introduction of biomass fuels can cause fouling and corrosion due to the varying presence of potassium , chloride and other ash components which can form low melting material that can adhere to tubes and furnace internals. The presence of such materials in coal ash and flue gas cleaning by-products can also affect the possibility for recycling these as construction materials. Such factors also cause limitations in the

---

[34] The status of large scale biomass firing. IEA Bioenergy Task 42, 2016

[35] http://www.eubia.org/index.php/about-biomass/co-combustion-with-biomass/european-experiences-in-co-combustion

[36] Cofiring of biomass in coal-fired power plants – European experience. C Henderson, IEA Clean Coal CentreFCO/IEA CCC workshops on policy and investment frameworks to introduce CCT in Hebei and Shandong Provinces, China, 8-9 and 13-14 January 2015

co-firing rate. Therefore, for very high blend-rates, and also for complete conversion, wood pellets are used. Saw dust pellets ("white pellets") are relatively clean, but are also available in consistent quantities in the quantities, i.e. millions of tons per year, that a power plant requires.

Indirect co-firing is also less common, but has the advantage of allowing use of fuels that could not be used directly in a power boiler due to contamination or ash properties. Since the fuel is gasified there is an opportunity to clean the gas prior to it being fired in the boiler. In most installations, some particulate separation is carried out but, even if some installations initially had further cleaning as a target, no other cleaning is included. To achieve economy in indirect co-firing, plants should have a fairly large capacity, with commercial installations that have been built ranging from 70-140 MW thermal, e.g. contributing of the order of 25-50 MWe when fired in a power boiler.

Direct co-firing or more recently full conversion has been widely used across Europe for the last two decades and there are numerous examples of installations in the cited references[34, 35, 36] and in other reports[37] where direct co-firing is or has been used. Full conversion is rapidly gaining ground as the coal fired power stations are faced with the drop in power price and capacity factors, while biomass energy is promoted. Examples of this include two out of six units at Drax, each having a capacity of 660 MWe which have been converted without loss of capacity or loss of efficiency, and a third one which is in planning (with some difficulties based on state-aid). The fuel used is pellets from the USA, where Drax has invested in an integrated supply chain. In Lynmouth, a 440MWe is also being converted after passing the sate-aid investigation. Similar developments are in progress in several of the large-scale, central installations in Denmark. In Denmark, the use of coal is expected to be phased out by 2020 and the power plants that are not being decommissioned are undergoing or will undergo conversion. In Gardanne France, EON is revamping what was once the largest coal-fired CFB power plant, a 250 MWe unit, to operate on wood chips at 170 MWe[38], while in Canada the 200 MWe Atikokan Generation Station in Ontario has also been converted[39].

There are also examples of the construction of new, large dedicated biomass thermal power plants, e.g. the Engie plant, a 200 MWe plant at Polaniec, Poland and several plants in the range of 100-300 MWe that are in planning in the UK. Also a large number of smaller biomass power plants, ranging from 10-100 MWe are built in the EU[37], the USA[40] and elsewhere. However, stand-alone power on greenfield sites is costlier and less efficient than large scale power plants and requires a preferential price mechanism, while having lower total efficiency that biomass CHP plants, such that the latter are more competitive if heat sales are possible.

Cost data for co-firing installations from references[41],[42] are found in Table 5. Costs for new biomass plants are discussed in the section on CHP.

---

[37] Large Industrial Users of Energy Biomass. IEA Bioenergy Task 40, 2013.

[38] PROJECT PROFILE: CFB, France Gardanne Coal to biomass conversion. Doosan Lentjes GmbH

[39] http://www.opg.com/generating-power/thermal/stations/atikokan-station/Pages/atikokan-station-biomass-conversion-project.aspx

[40] http://biomassmagazine.com/plants/listplants/biomass/US/

[41] Technology Data for Energy Plants 2014. Energistyrelsen, Energinet.dk

[42] Electricity Generation Costs July 2013. UK department of Environment and Climate Change (DECC)

Table 3 Co-firing cost data

Technology	Investment	Operating Costs	
		Fixed	Variable
Co-firing, low level	42-177 £/kWe	10,10 £/kW/y	1-3 £/MWh
Biomass conversion	360-760 £/kWe	40,90 £/kW/y	1-3 £/MWh
Biomass conversion pellets	130-230 €/kWe	57,2 €/kW/y	2 €/MWh
Biomass conversion, chips	130-230 €/kWe	57,2 €/kW/y	2 €/MWh (+ 0.3 €/MWh drying)

When considering that new large power plant capacity costs start at 2,000 €/kWe, it is clear that it is attractive to ensure the continued use of an installation by co-firing or even by a complete conversion to biomass.

In many countries, the support system calculates the biomass power as the proportion of the total generated power times the energy content of biomass fuels divided by all fuels used, and hence benefits can be claimed even if biomass is not the main fuel used.

The contribution of bioenergy to operational flexibility

Bioenergy can contribute to fuel flexibility, but in a PF boiler it is the steam system and the turbine that limit adaptation to load changes, while the design sets the minimum stable load. Furthermore, there is a significant loss in efficiency when reducing load. These factors are not fuel related. In fact, one could say that the objective of a high biomass usage up to complete conversion is inflexibility rather than flexibility, as the new investment must be expected to result in more operating hours, additional price benefits or extended lifetime of the existing assets relative to a business-as-usual situation firing coal.

Using co-firing in separate burners can possibly allow the fraction of bioenergy input to be increased at part load relative to full load but it has little impact on the dynamics of the load control.

Another way of seeing the contribution of bioenergy in the balancing process is that it will have a growing importance. Since thermal power plant capacity is being reduced overall, in a given coal-firing capacity, as the use of bioenergy in power generation is increasing by e.g. conversion or co-firing, the relative importance of bioenergy in thermal power generation will increase.

However, there is also the energy consumed during start-up and shut-down even if no power is produced, in particular for supercritical units when a lot of steam is dumped to the condenser. The more flexibility required by the boiler operation, e.g. in weekly or two-shift scheduling or as spinning reserve, the more energy is consumed. For a base-load plant, the auxiliary fuel consumed is less than 0.5 % of the total fuel energy, whereas a mid-term boiler would use around 1.5 % and a boiler that operates with many starts and stops could consume 5 % or more of the total energy input as auxiliary fuel[43].

[43] Power Generation from Coal. Measuring and Reporting Efficiency Performance and CO2

For 500 MW base-load plant with 95 % capacity factor and 40 % efficiency, 0.5 % equates to an auxiliary fuel consumption of up to 52 GWh, or 4,700 m3 of oil consumed. For a similar mid-merit plant, at say 50 % capacity factor representing weekly operation, the fuel consumption is 82 GWh or 7,000 m^3, and for a unit at only 40 % capacity factor with frequent starts and stops, e.g. a two-shift schedule, it is as much as 220 GWh or 19,000 m^3. The Indian regulations[44] based on operating practice and with consumption being in proportion to plant output capacity, indicate that for a boiler of 500 MW, an estimate of fuel oil consumption for base load plants is 0.25 m^3/GWh power produced, including seven start-up events, with each start-up typically requiring 50-90 m^3 of fuel oil. For a base-load plant this would mean around 1,000 m^3/year fuel oil consumed or 11 GWh, or only 0.1 % of the total energy, i.e. lower than the figure above. However, adding additional starts produces numbers that converge for daily starts.

The conclusion is that a PF power plant could use somewhere between 1,000 and 20,000 m^3 of fuel oil per year, which could be substituted by e.g. pyrolysis oil. The use of a bioliquid as a substitute for fuel oil has been implemented in PF power plants, e.g. in the UK. Since the NFFO system apportioned the power output on the basis of total energy input, regardless of whether a fuel was associated with power to the grid or not, tall oil pitch was used and certificates, or ROCs, were obtained for this fuel.

Conclusions on role of balancing bioenergy in relation to PF boilers

The constraints in the flexibility of operation of PF power plants is typically only on the firing side with regard to the minimum stable load. On the other hand the dynamic rates of load change etc. as well as start-up times are dictated by the steam system and the turbine. This is to avoid material strength deterioration due to heat gradients in the materials resulting from load changes, i.e. these constraints are not fuel related. The use of designs to decrease the minimum load from, say, 40 % in old power plant boilers to 20-25 % in new boilers involves the number and type of burners. Here, separate burners for biomass can be used to assist at lower loads, but this design is not very common relative to firing biomass in the same burner as it involves changes to the furnace wall in existing plants.

Co-firing with biomass can be carried out from low rates, typically below 10 % energy input up to 100 % biomass firing. For high co-firing rates a clean biomass is required in large quantities, favouring biomass pellets for technical and logistical factors. A complete conversion of a power plant to biomass does not really increase the flexibility of the installation relative to coal. Instead the expectations should rather be to improve the capacity factor in order to recover the cost of the investment and also considering the higher cost of the fuel.

Another, and less demanding application where biomass fuels could be feasible, while also in a sense making the overall system more flexible, is to substitute the fuel oil used for firing up and down when the main burners of the boiler are outside of their stable operating range. Fuels that have been used include tall oil pitch, while pyrolysis oil could also be considered for this application. A typical power plant boiler could use between 1,000 and 20,000 m3 of auxiliary fuel oil per year, depending on the operating conditions.

Emissions. IEA Coal Industry Advisory Board (CIAB). OECD/IEA, 2010

[44] Recommendations on Operation Norms for Thermal Power Stations. Tariff Period -2014-19. Government of India. Ministry of power. Central electricity authority. NEW DELHI. January - 2014

So, technically, in terms of increasing the flexibility of large power plants, the change of fuel to bioenergy fuel does not really affect the flexibility of operation as firing and steam systems are the bottleneck. However, as the controllable thermal power plants will on the one hand contribute less to the overall balance in the future, while on the other hand co-firing and full conversion to bioenergy fuels will increasingly be used in such installations, the importance of bioenergy for grid balancing will in relative terms become more important in the future.

Biomass use and balancing characteristics of Municipal Combined heat and power (CHP) production

The role of CHP in the electrical sector

Co-generation, or combined heat and power (CHP) generation of electricity is a significant activity that contributed around 10 % of all power produced or 2,200 TWh[45] in 2011.

The share of CHP generation in total power generation is typically below 20 % in most countries[46, 47], with some notable exceptions in Northern and Eastern Europe (e.g. Russia where it amounts to 30 %).

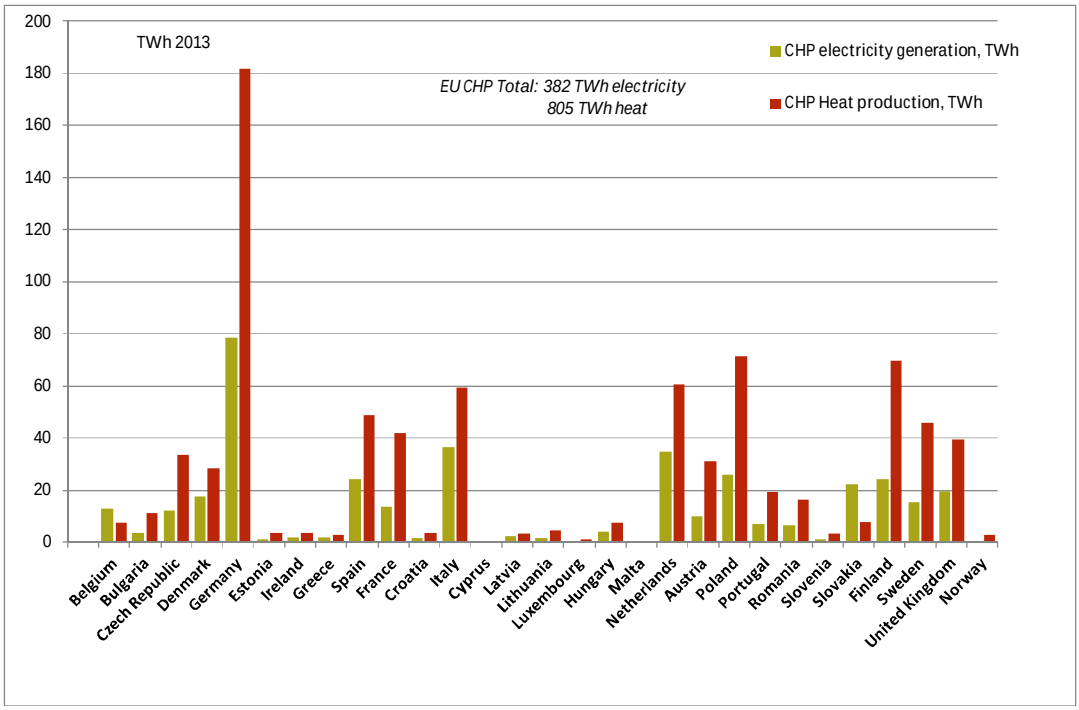


Figure 5 The production of power and heat in EU28+ Norway[48]

Looking more closely at the EU28, Figure 5 and Figure 6, the total production of electricity in CHP

[45] Linking Heat and Electricity Systems. IEA 2014

[46] Combined Heat and Power. IEA 2008

[47] http://ec.europa.eu/eurostat/documents/38154/4956229/CHP+data+2005-2013/62e87958-0b9a-4195-af70-356493e12233

[48] http://ec.europa.eu/eurostat/documents/38154/4956229/CHP+data+2005-2013/62e87958-0b9a-4195-af70-356493e12233

plants was 382 TWh in 2013, with Germany close to 80 TWh and Spain, Italy, the Netherlands, Poland, Slovakia, Finland and UK, with 10-20 TWh, being the leading producers.

In terms of the share of electricity generation, many countries are close to the EU average of about 10 %, except for Denmark, Latvia, Lithuania, the Netherlands, Slovakia and Finland which have a considerably higher share, from 30-80 % of CHP power in the total electrical generation.

Focusing on the share of renewables, i.e. bioenergy and biogenic wastes, the Nordic and the Baltic states together with Austria and Portugal are significantly above the EU average of 20 %, whereas countries with a high production of CHP power such as Germany, Italy, the Netherlands, Slovakia and others are clearly below the EU average.

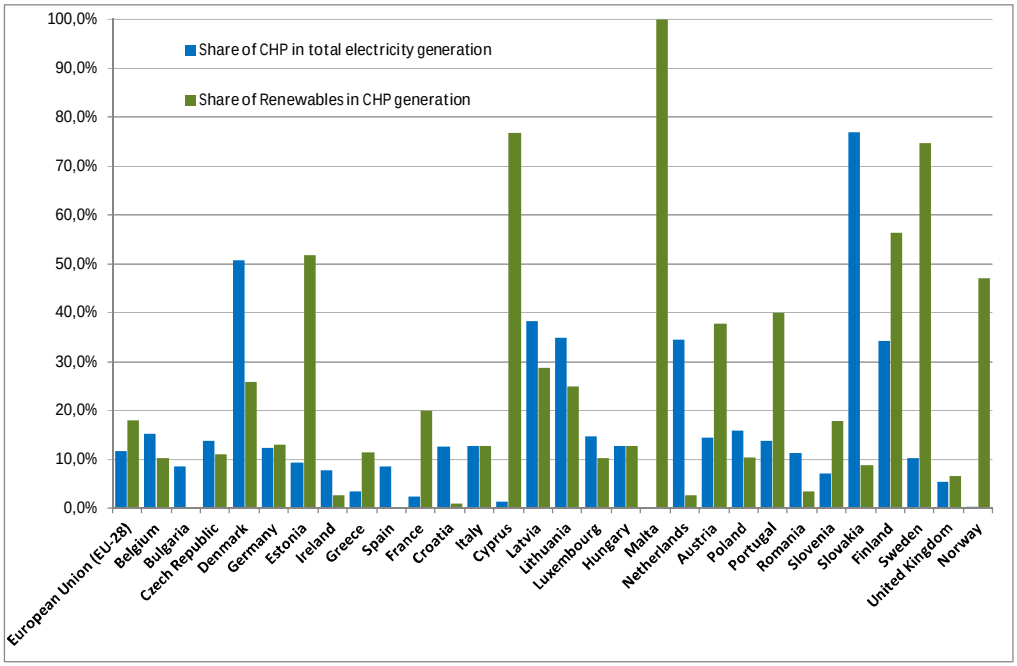


Figure 6 The share of CHP in electric power generation, and the share of renewable fuels in CHP[48]

District heating and cooling technology

District heating consists of a network of pipes for closed-loop distribution of heat connecting the buildings in a neighbourhood, town centre, a whole city or even a regional centre with several cities. Each client is connected to the system via a sub-station where energy usage is measured for billing purposes, and heat exchangers transfer heat to the secondary closed loop heating system that provides heat and hot water in the building. (This indirect connection is most common, but there are also direct connections without a secondary loop in the building, which is far less common.) Similar systems are also in use to provide district cooling but thus far not to the same extent as heating systems.

The network is typically supplied from one or more centralized plants, sometimes complemented by a number of distributed heat producing units embedded in the network, and/or heat accumulators for short-term storage of heat. The heat supply is typically via central and distributed combustion boilers and, more recently, also electric boilers, industrial waste heat, heat pumps, gas engines and solar heating. More long term storage of heat is also being discussed.

District heating systems need a certain geographical density of heat consumers to be economical.

Consequently, in Sweden only 50 % of villages between 1,000 and 3,000 inhabitants, representing a potential district heating peak heat demand of 5-15 MW each, have a system[49]. For larger urban areas, district heating systems are increasingly more common where connection rates can go as high as 80-90 % of the market.

The use of heat distribution to buildings is not new[50]. Systems using steam as the heat carrier were introduced in the USA already in the 1880s, and are still operated on Manhattan. The steam system was replaced in the 1930's by pressurized hot water with an average supply temperature well above 100 °C. In the 1970's, the "third generation", sometimes referred to as "Scandinavian district heating technology" became the leading technology, characterized by an average supply temperature below 100 °C with a return temperature of 40—50 °C and the use of standardized and prefabricated components. The industry is now discussing a "fourth generation" that, in combination with new and renovated building, can decrease the supply temperature even further, to the level of 55-60 °C in the supply and 30-40 °C in the return, and use more and more pre-fabricated light-weight polymer materials in the piping.

The heat loss in the grid system, which can be substantial[51] depending on the grid size and installation quality and range from a few % up to 20-30 %, is higher for a higher supply temperature as the surrounding temperature is more or less constant over the year. The supply capacity is more or less proportional to the supply temperature as the return temperature does not vary to the same extent. Therefore the supply temperature is varied over a range with the load to get a balance between the desired supply and the associated losses.

The use of district heating networks as a basis for CHP power generation in boilers is governed mainly by the heat load and can include both base load and mid-term heat supply during the so-called "firing season", which is typically from September to May in Northern Europe and is shorter in more southern locations. The design covers a certain fraction of the heat demand to allow base load or mid merit operation but does not cater for peak load heat demand whose hours are relatively few. In Sweden the rule-of-thumb design for a district heating CHP installation is 5,000 full load equivalent operating hours per year, while further south in Europe this number may go as low as 4,000 full load equivalent hours per year.

This usage pattern imposes limitations on the use of biomass district heating CHP systems for grid balancing and control, separate from the direct physical limitations of the components described below.

Since district CHP plants are typically not in operation in the summertime and may have technical limitations in terms of ability to reject sufficient heat in a period of low demand, the contribution to grid balancing would only be possible after a lengthy cold start-up, and because of heat rejection limitations the MCR output may not be reached.

On the other hand as the peak in power demand coincides with the peak heat demand in the

---

[49] Småskalig fjärrvärmebaserad kraftvärme. Svensk Fjärrvärme. Rapport I 2009:2

[50] 4th Generation District Heating (4GDH) Integrating smart thermal grids into future sustainable energy systems. H Lund et al. Energy 68 (2014) pp. 1-11

[51] Status Report on District Heating Systems in IEA Countries. Thomas Nussbaumer. IEA Bioenergy Task 32, Swiss Federal Office of Energy, Zürich, 19 December 2014

wintertime, district heating CHP plants are typically operated at close to the MCR output of both heat and power, i.e. the room for increasing power is very limited.

District heating system energy supply and societal importance

District heating systems are globally very important for the indoor climate in residential and service sector buildings. It has been difficult to find a consistent set of data for the global use of district heating. In 2014[52], the IEA reported that heat supply in buildings was around 1,500 TWh. However, in a separate IEA report[53], it is stated that district heating supply in 2006 in Russia alone was 1,700 TWh, while Ukraine consumed 200 TWh. Finish Energy estimates that 1,700- 2,400 TWh of district heating is supplied in Russia[54]. Even if this is the largest exploitation of the technology in the world, it is reported that the systems are old and need maintenance and reinvestments.

In China it was reported that there was over 780 TWh of district heating45[,55], representing about 23% of residential and commercial heating demand, in 2011, and that this increased to 881 TWh in 2013[56], i.e. a high growth rate involving new technologies.

As for the rest of the world, data is lacking. For the EU28 and some other countries, the sales of district heating are shown in Figure 7.

With the exception of the countries already mentioned, Germany and Poland both have consumption around 70 TWh, while for Sweden and Korea it is just below 50 TWh. A group of other countries in the EU are between 20 and 35 TWh and the remaining countries are below 10 TWh. The total EU28 figure for district heating sold is 399 TWh56. However, in a different study[57,] the figure is higher. The difference appears to be some 50 TWh of district heating used in industry, this figure being some 10-12 % of the energy required to heat buildings in the EU at present. The vision document of the DHC+ Technology platform defined a total sales volume of 556 TWh[58] at a value of 20-30 billion €.

---

[52] HEATING WITHOUT GLOBAL WARMING. Market Developments and Policy. Considerations for Renewable Heat. IEA 2014.

[53] CHP/DHC COUNTRY PROFILE: RUSSIA. IEA International CHP/CHC Collaborative.

[54] http://energia.fi/en/energy-and-environment/district-heat-and-district-cooling/district-heat-global-scale

[55] Comparison of district heating systems used in China and Denmark. The 2nd International Research Conference. Lipeng Zhang, DTU, 5-6 November 2013 Brussels

[56] Statistics overview 2013. Euroheat Power

[57] Renewable Based District Heating in Europe - Policy Assessment of Selected Member States. IEE project towards 2030-dialogue. August 2015.

[58] District Heating Cooling. A vision towards 2020 – 2030 – 2050, DHC+ Technology Platform. 2012

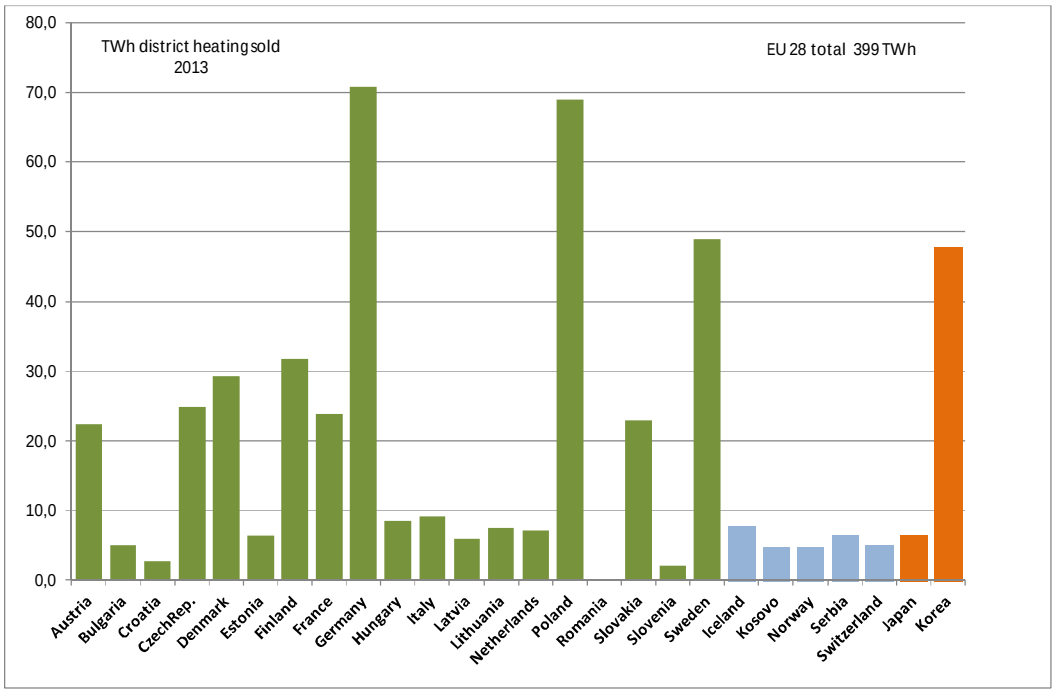


Figure 7 The sales of district heating in 2013 in EU28 and some other areas[56].

Contrary to what could be expected, the use of district heating is quite widespread in the EU. Figure 8 shows where district heating and cooling systems are used, but without any size differentiation.

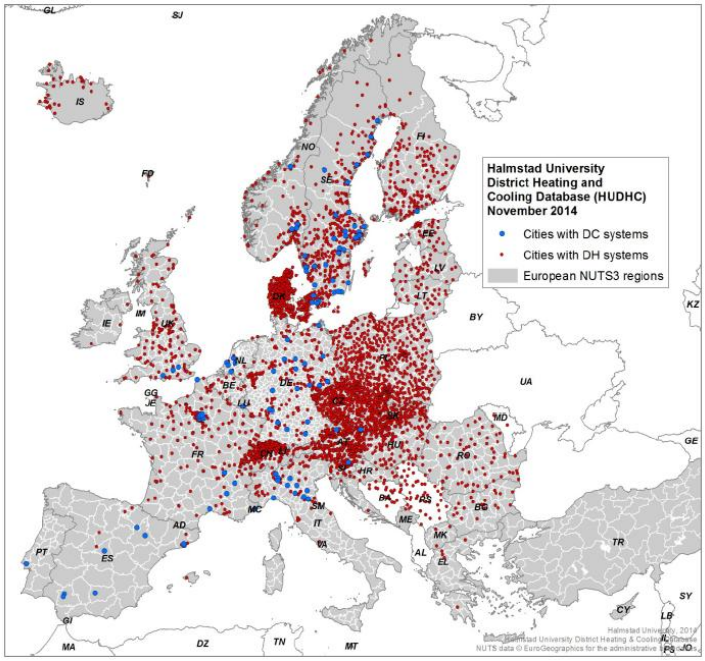


Figure 8 Cities where district heating and cooling was used to some extent in 2014[59]

The map shows a clear concentration in the Nordic EU members, East Europe and Switzerland but the technology is also applied in Germany, the Benelux countries, France and the UK to some considerable extent, and less so in the Mediterranean countries. On a regional basis, district heating systems are installed in 58 % of the NUTS3 regions.

There are over 6,000 district heating systems[60], both small and large, in operation in Western Europe, predominantly in the EU. Most of these are used in urban areas and cities with more than 5,000 inhabitants.

The graph in Figure 7 above showing district heat in TWh per year, is strongly influenced by the size of the country. Another way of seeing the importance of district heating in the respective societies is the extent to which the population is covered by district heating, Figure 9. The Nordic countries, the Baltic states and some of the Eastern European countries have from almost 40 % to more than 60 % of the population served by district heating, whereas for the rest of the EU28 states, the figure is only 5-20 %. While data for many countries is lacking, it is noticeable that a country such as Korea has 15 % of the population served by district heating while in USA it is only 3 %.

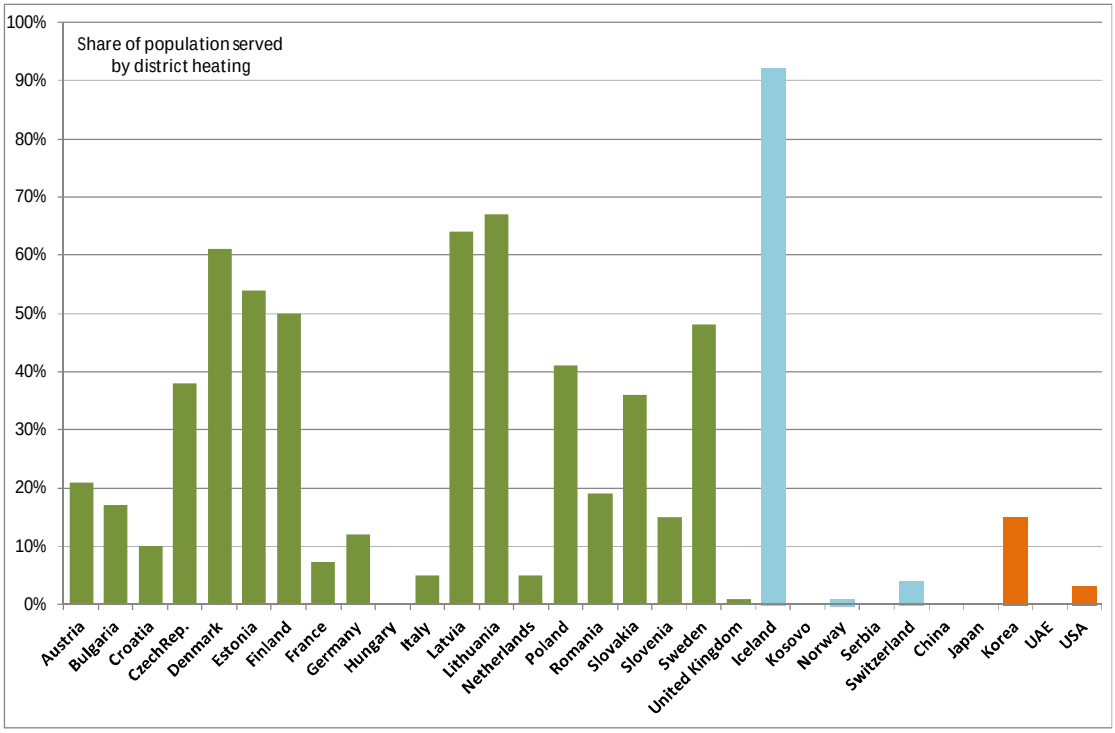


Figure 9 The share of the population served by district heating in 2013 in the EU28[56].

Fuels used in combustion boilers have traditionally been fossil fuels such as coal and fuel oil, although there has been a change recently to increasingly use natural gas, wastes and biomass.

[59] District heating in future Europe: Modelling expansion and mapping heat synergy regions. Urban Persson. Dissertation no (new series) 3679. Chalmers Technical University, 2015.
[60] HEAT ROADMAP EUROPE 2050. Euroheat & Power 2012 and 2013.

The fuels used for the production of district heating in 2012 are shown in Figure 10 (Shown as gross fuel, i.e. includes losses but also power produced in CHP plants). The balance between heat only and cogeneration cannot be distinguished in the statistics for CHP systems alone, but the IEA reports that 79% of the total district heating in OECD countries was produced by co-generation plants[45] in 2011.

Larger boilers (> 30 MW thermal) with longer operating periods often have steam turbines to co-generate heat and power. This is further described below

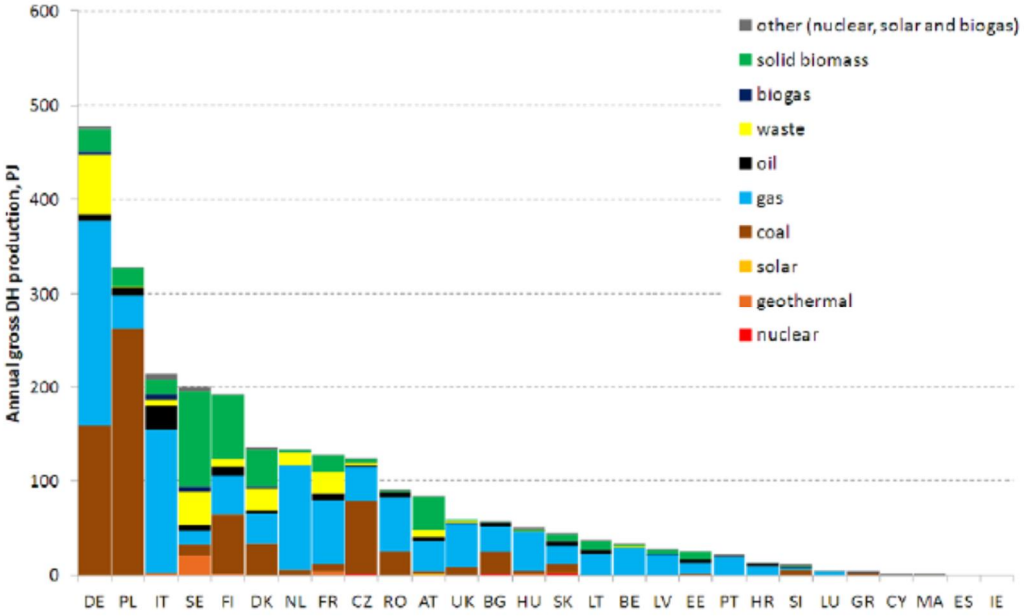


Figure 10 Fuels used in district heating 201257

The figure shows that for each country, there is a wide range of fuels and technologies in use. Nevertheless, the majority of the fuels are from fossil sources, and with the exception of Germany and Poland where coal is used quite extensively, it is natural gas. Also waste incineration is an important source of district heating in some countries. Heat pumps and geothermal systems together with solid biomass are the most common renewable energy sources.

The use of bioenergy is in particular high in Sweden, Finland, Denmark and Austria. The amount of renewable district heating in 2012 was estimated at 113 TWh, predominantly involving bioenergy[57].

There are two trends that will affect the energy usage for district heating in the future. One is the expansion in the use of district heating, both in marginal expansions to include new buildings in the supply network and in the establishment of new district heat grids. This also includes a trend towards integration of grids where possible to allow an increased use of CHP power generation. Another trend, which goes in the opposite direction, is the declining energy use in the buildings as older buildings are improved or replaced. The overall impact of these two trends is different in different areas. In the case of Sweden, which can be seen as a mature market, the use of district heating is not expected to increase and may actually decrease. Furthermore, industrial waste heat and other forms of heating for individual buildings such as heat pumps and solar heating can reduce the potential for CHP generation.

In Eastern Europe, there is also a lower potential to expand the grid, as refurbishment of the grid will reduce losses such that the net effect may result in a net decrease in use. In other locations with low grid coverage today, entirely new grids can be established to replace individual heating

solutions, but may then involve other renewable energies or CHP based on natural gas rather than on bioenergy.

The NREAPs (National Renewable Energy Action Plan) of the EU member states indicate a growth in the use of renewable district heating from 113 TWh in 2012 to 206 TWh in 2020. However the 2012 data shows that in many countries the expansion thus far is less than would be expected from a smooth line progression, and in particular in Germany and France where a large expansion was projected from 7 and 6 TWh in 2012 to 30 and 37 TWh, respectively by 2020. Furthermore, while bioenergy is dominating at present, solar and geothermal heating is expected to make large inroads in the future.

In the scenarios developed for the Impact Assessments of the EU Energy Road Map for 2050[61], the use of district heating is foreseen to contract from the current level of close to 400 TWh down to 40- 150 TWh by 2050. This was based on an expectation that the energy use in buildings is reduced by some 61 % in the same time period and that other renewable energies and heat pumps take a larger share of the production capacity due to the anticipated high cost for establishing new grids.

In the cited report[59] by Euroheat & Power, a scenario using the input data of the EU Energy Efficiency scenario was given in which district heating is increased from the present 12 % to 30 % by 2030 and 50 % by 2050 of all heat used in buildings, while the reduction in energy use in building is only 34 %. This would mean that based on the current 400 TWh district heating demand, this would result in an increase up to 1,200 TWh by 2030 and 1,700 TWh by 2050. Even if district heating is expanded by factor of 4-5, the production based on CHP and boilers, where bioenergy could be one of the main fuels in the future, is only expected to be increased by a factor of 3, to 600 TWh by 2030 and remain stable to 2050. This expansion is considered to involve an increased use of gas-based CHP in addition to bioenergy.

In conclusion, the expansion of bioenergy-based district heating in the future appears to be moderate compared to the present situation and cannot be expected to be more than doubled, unless very strong policy measures are introduced in areas where bioenergy and district heating are not in common use today. However, in Figure 10, there is a coal usage for district beating above 100 TWh that is probably a low-hanging fruit.

District cooling energy supply and societal importance

District cooling is not as frequently used as district heating. The largest user of district cooling is the USA with almost 25 TWh, covering 6% of the country's space cooling demand. In the EU only 2 or 3 TWh is supplied[56, 58] and Sweden and France are the leading countries. The present figure only represents 2 % of the market[58] for space cooling and because it is often associated with compression refrigeration, also impacts on the electrical demand.

Industrial CHP systems

Energy-intensive industrial sectors such as chemicals, refining, pulp and paper, and food and beverage typically have high process-heat requirements in the temperature range from 25 °C up

[61] COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS Energy Roadmap 2050 {COM(2011) 885}. Impact Assessment Annexes

to 1,500 °C, or above. They also have considerable electricity needs. Co-generation technologies are capable of providing heat up to 400 °C or above using direct heat transfer, or an intermediate heat carrier such as thermal oil, steam or hot water as an energy carrier between heat generation and consumption. Almost all process-heat demand in the food sector is well below 400 °C, and this also applies to approximately 83 % and 51 % of the total heat demand of the pulp and paper sectors and chemicals sectors, respectively[45]. Globally, the estimated maximum theoretical technical potential in 2011 for heat co-generation was 4.8 exajoules (EJ) or 1,300 TWh in the chemicals sector and 3.3 EJ, or 900 TWh, in the pulp and paper industrial sector. Other sectors with very large and established CHP production are the (cane) sugar and palm oil industries.

However the use of cogeneration depends on energy prices and regulatory considerations. The data available on global use of heat demand from co-generation is not available. As noted above, co-generation of electricity contributed around 10 % of all power produced, or 2,200 TWh in 2011. Industrial CHP plant generated 26% of total global electricity generation from co-generation[45], i.e. 550 TWh, but with the difference that the share was 37% in the OECD countries while it was only 15% in non-OECD countries.

Industrial CHP systems differ from district heating system in that the main heat usage is as steam, even if hot water for space heating can also be supplied and the distribution area is limited to one or more industrial activities on a restricted site. Industrial CHP plants typically work with several steam pressures, e.g. in pulp and paper mills the live steam produced is in the range of well over 100 bar, including reheat, down to 40 bar. The actual operating conditions depend on the age and scale of operation, which can cover steam production of 200 MW to more than 500 MW for large recovery boilers to less than 200 MW. Up to 4 pressure levels may be in use (e.g. 15-20, 10-15, 5-10 and 2-5 bar respectively). It is also possible to combine the extraction-back-pressure system with a condensing stage. In reference[62] the state of the art for industrial CHP boilers was indicated.

In other industries, the live steam conditions are more moderate, but 60-80 bar boilers are now the state of the art in e.g. sugar cane mills.

The industrial bioenergy CHP systems are also on average typically larger than district heating CHP systems. Of over 40 industrial CHP plants in Sweden, 11 were above 50 MW installed capacity and 8 were in the range of 25-50 MW.

There is another difference in that most industrial processes operate at fairly steady conditions over the year as the heat load is guided by industrial production and is less affected by climatic conditions. This means that the equivalent annual full load operating hours are more than for a district heating plant. However, in the sugar beet and sugar cane industry, as the milling season is typically only 2-6 month per year, few of the installed CHP plants operate outside of the milling season as this would mean more operation in condensing mode.

In the Kraft paper and pulp industries, the black liquor recovery boiler is operated in combined

---

[62] Large Industrial users of energy biomass Esa Vakkilainen, Katja Kuparinen, Jussi Heinimö. IEA Bioergy Task 40. 2013

heat and power mode to recover the cooking chemicals. However, even if the black liquor combustibles represent majority of bioenergy there is also bark and other biomass residues available on site. For an integrated pulp and paper mill the combined energy consumption of such a mill at present consumes effectively all the biomass wastes as the bark boiler(s) are operated at high load to meet the steam demand. However, if only Kraft pulp is processed, there is an excess of black liquor and biomass residues, relative to the heat demand, such that the bark boiler(s) are operated at full load when the power prices are high enough to justify the use of excess steam in a condensing turbine.

In the case of mechanical pulping, there is only the bark and other residues for fuel, while the electric consumption is high.

In general, this means that the pulp and paper industry is a net consumer of electricity. In the case of the Swedish mills only three mills are net producers while about 10 mills buy 30-50 % and the remaining 40 mills buy 50 %-100 % of their total consumption of electricity. The Swedish pulp and paper industry had 1.2 GW installed capacity in 2015 and produced close to 6 TWh per year[63], [64] from some 42 TWh of black liquor and 7 TWh of additional solid biomass. However, the consumption of power was 21 TWh. There is a similar situation in the Finish pulp and paper industry where production of power has been around 10 TWh for a number of years, while consumption has been twice as high[65].

The production of pyrolysis liquids from biomass is also typically associated with the valorization of by-products such as pyrolysis gases and charcoal residues in a CHP facility.

Biofuels production is also associated with industrial CHP plants. First generation ethanol plants require steam for the process, mainly for product upgrading. One of the methods for such plants to meet the RED requirements on GHG reduction from the product is to increasingly use internally generated by-products and external biomass for CHP production. For second generation ethanol, there are similar demands for the purification of the product, while the lignin by-product is the major output in terms of tonnage, and is used for CHP purposes in the few industrial plants available today.

Depending on the industry, the temperature/pressure level or levels vary. For practical reasons, as the steam pressure becomes very high, going above 250 °C and using superheated steam only is in general not energy-efficient. Besides, for higher temperatures, the exhaust steam conditions would leave little room for co-generation of electricity.

Other types of bioenergy CHP systems

There are also other types of CHP systems used within industrial, commercial and residential settings. These are typically at smaller scale and use engines or micro-turbines.

With regard to bioenergy, the use of AD biogas in gas engines is frequently applied in waste water treatment facilities, the food industry, pulp industries, farms etc. There is also an increasing interest in small scale gasification co-generation based on solid biomass. However, such units are typically small and are not really suited for sizes from 40 kWe to 1 MWe, and therefore they have

[63] Bioenergi. Biokraftkartan 2015.

[64] Swedish Energy Agency, Energy in Sweden 2015.

[65] https://www.forestindustries.fi/statistics/resources/55-Energy/

limited impact on grid balancing.

In addition biomass-fuelled ORC co-generation plants of up to 2 MW electric are also being introduced, as at this scale the efficiency is higher than for a comparable steam cycle. The operation of such units is not subject to the more demanding regulations of steam-based systems, such that O&M cost are reduced.

Such small systems are typically connected to the distribution system and are not involved in grid balancing, nor have they potential to contribute significantly. However, auto generation of heat and power does have an impact on the demand side, as it reduces the demand for power during peak periods. Alternative ways of providing heat by electrical heating and heat pumps additionally reduce the demand.

Bioenergy CHP boilers

There are four types of combustion boilers for biomass, see Figure 1, including grate furnaces, bubbling bed or stationary fluidized bed (BFB), circulating fluidized beds (CFB) and pulverized fuel combustion (PF). These technologies are described in more detail elsewhere[66]. Grate firing is typically used at smaller scale, from a few MW thermal input up to slightly over 100 MW. FBs have a range from 10-300 MW thermal and CFBs from 50 up to over 700 MW thermal[67]. PF firing is used both at smaller scale in heat only boilers and in very large installations where it typically can entirely replace coal and revitalize an existing asset , e.g. Drax in the UK, with 660 MW electrical, i.e. on the order of 1,600-1,700 MW thermal. There are no other such large new investments in biomass boilers, and the limitation is otherwise of the order of just over 500 MW. In reference[62] a number of large scale biomass boilers are highlighted.

Figure 12 gives an overview of the operating conditions for CHP plants in relation to coal fired types of boilers discussed in the Section on Technical characteristics of PF boilers. In this graph the electrical efficiency is given in relation to the steam parameters based on vacuum condensing operation.

However, most district heating systems and industrial systems use back-pressure or extraction-back-pressure turbines and balance the heat produced via these systems. The condenser pressure is set by the supply temperature in the district heating network, so that the power to heat ratio is the key defining the technology, instead of the efficiency to power. Since the heat generation is the primary driver for constructing the boiler, this ratio indicates how much electricity can be cogenerated, Figure 13. A value of 0.5 indicates that for a design capacity of 1 MWh of heat, 0.5 MWh of electricity can be supplied by co-generation.

---

[66]

[67] High-efficiency biomass-fired CHP plants. Maria Jonsson, Vattenfall Research and Development. 2011

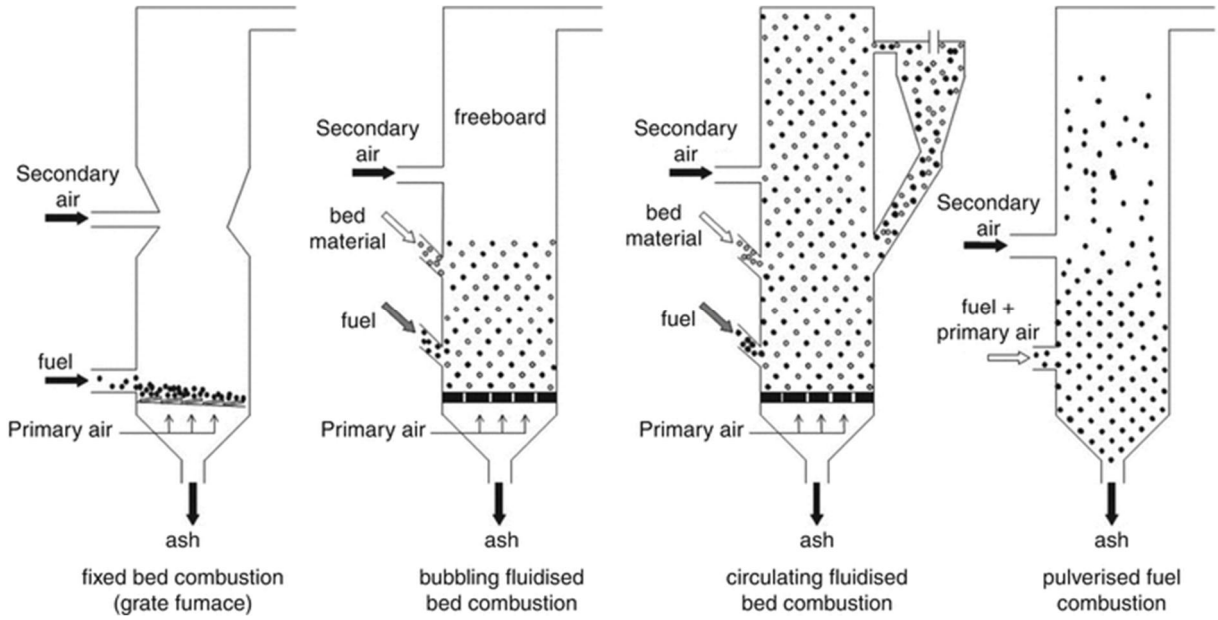


Figure 11 Biomass combustion technologies[68]

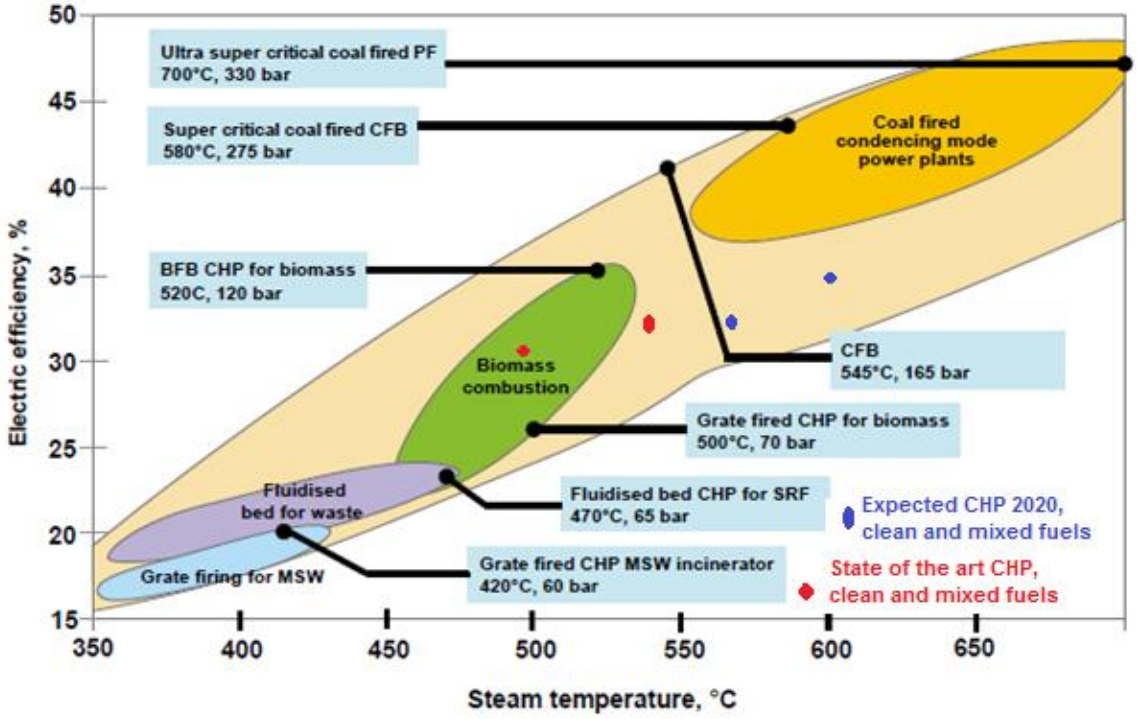


Figure 12 Electric efficiency vs. technology and performance parameters, Predicted bio-CHP developments[69]

---

[68] Biomass Combustion for Electricity Generation, Andreas Wiese . In Renewable Energy Systems, Springer Verlag 2013

[69] Biomass Technology Roadmap. European Technology Platform on Renewable Heating and

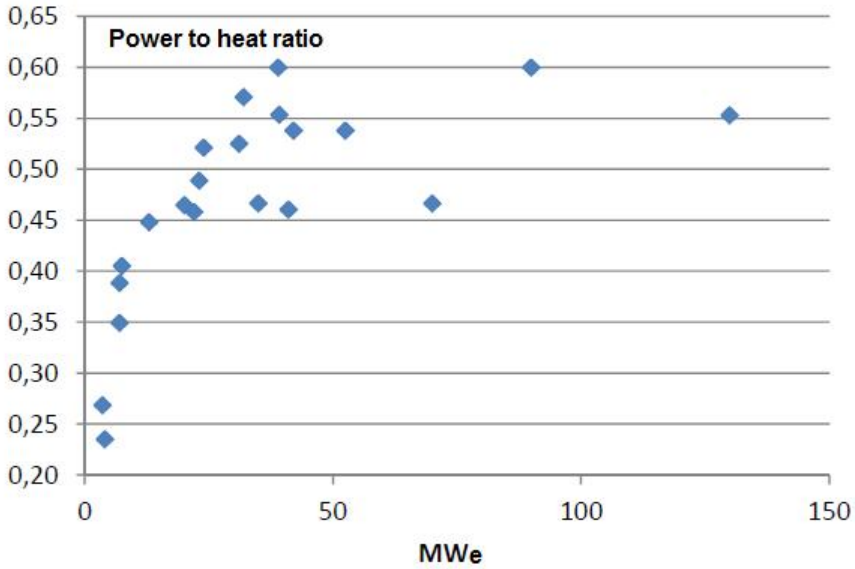


Figure 13 Typical power to heat ratios in district heating systems[70]

Table 4 Performance data for District Heating Cogeneration boilers[71], [72], [73]

	Wood chips			Wood pellets	Black liquor
Operating sequences time duration	Grate 5-30 MW	FB 30-50 MW	CFB 30-80+	PF >> 100	Kraft boiler 200- 600 MW
Hot (<8 hrs off), hrs	2	2	2	2	
Cold, >(48 hrs off), hrs	4	9-10	9-10	5-8	
Efficiency, full load, net power%	22-25	25-30	25-32	36-44	
Efficiency, full load, heat %	64-61	61-56	63-54	49-0	
Power to heat ratio	0.35-0.40	0.4-0.5	0.5-0.65	0.7	

Cooling 2014.

[70] El från nya och framtida anläggningar 2014. Rapport 14:40, Energiforsk Sweden

[71] Technology Data for Energy Plants 2014. Energistyrelsen, Energinet.dk, Denmark

[72] El från nya och framtida anläggningar 2014. Rapport 14:40, Energiforsk Sweden

[73] Thermal Power Generation in 2030: Added Value for EU Energy Policy. M. Farley EPPSA. All Energy 2015, Glasgow UK.

Total boiler efficiency %	86	86	86-88	85-44	75 %
Flue gas condensation heat %	10-18	10-18	11- 19	0	n.a.
Total plant efficiency %	96-104	96-104	97-106	85-44	
Minimum load, %	30-40 20 w. back-up fuel	30-40	30-40	25 20 w. back-up fuel	
Ramp range load, %	40-95	40-90	40-95	35-95	
Load ramp rate, %/min	3-4	3-4	3-4	4 6 w. back-up fuel	
Primary frequency control	2-10 %/30 s	2-10 %/30 s	2-10 %/30 s	2-10 %/30 s	

The overall efficiency for biomass-fired CHP boilers is around 85 % irrespective of the size. However, the split between power and heat increases with increasing thermal capacity but levels of at 0.6-0.65 in district heating service. The limitations in this case are due to the steam conditions and because reheat cycles are being introduced at present in the largest units.

One feature, which is commonly applied when firing wet fuels, is flue gas condensation. In this case the district heat return water is utilized to cool the flue gas below the water dew points in a scrubber type of system and the heat of condensation is recovered in the district heating system by indirect heat exchange. This is further enhanced through humidification of the combustion air by means of the cooled scrubbing water, whereby the flue gas dew point is raised and the overall plant efficiency can go above 100 % on a LHV basis. When firing dry fuels such as straw and wood pellets, this is not feasible because of the mismatch between the flue gas dew point and the return cooling water temperature.

Table 5 CHP district heating plants cost data[70]

Capacity MWe	Investment €/kWe	Fixed op. cost	Variable op.cost
5, wood chips	5 900	155 €/ kWe/year	8.1 €/MWhe
10, wood chips	5 100	114 €/ kWe/year	7.8 €/MWhe
30, wood chips	4 000	76 €/ kWe/year	7.6 €/MWhe
80, wood chips	3 200	54 €/ kWe/year	7.1 €/MWhe

Capacity MWe	Investment €/kWe	Fixed op. cost	Variable op.cost
0.6-4, wood chips	3 600-4 900	3-4 % of investment per year	
10-50 wood chips	2 600	29 €/ kWe/year	3,9 €/MWhe
8-10, straw	4 600- 5 800	4 % of investment per year	
10-50, straw	4 000	40 /year	6.4 €/MWhe

Regarding capacities of CHP boilers, there were 91 waste and bioenergy CHP boilers in district heating in Sweden in 2015[63]. Of these, only 16 had an installed capacity > 50 MW, 12 were between 25 and 50 MW and the vast majority were below 25 MW.

CHP boiler load modulation

The CHP boiler units are in general able (or could be able with slight modifications) to deliver 2-10 % of their rated capacity as primary load support within 30 seconds at loads between 50% and 90% (FRC), even if for such plants this is not a typical requirement of the TSO in each jurisdiction. This fast load control is achieved by utilizing certain water/steam buffers within the unit. The ability to also engage in secondary frequency control, FCR, is more limited.

The secondary load control (EB) takes over after approximately 5 minutes, when the primary load control has utilized its water/steam buffers. Part load operation simultaneously affects both the heat load and power load. Since the main control for a district heating boiler is the heat load, this control may not always be available, requiring that other units are started to cover any residual heat load. The secondary load control is able to sustain the 5% load rise achieved by the primary load control, and even to increase or decrease further the load (if not already at maximum or minimum load) through the boiler/turbine load control. However, part load inherently reduces the balance of power to heat, such that when going down towards the minimum load of the boiler, the power/heat ratio is reduced considerably. This is somewhat determined for each boiler depending on how far down the superheat can be retained and on which type of pressure control is used (controlled or controlled sliding pressure).

The boiler load control is the most efficient means to modulate the and power production primarily controlled by heat load in the CHP boiler but there are also other means of increasing and decreasing the boiler heat and power output.

A method to reduce the power production fairly rapidly is to use the by-pass valve and route live steam directly to the condenser. This could be suitable when there is a relatively high heat load and where the power demand goes down. The power output could be decreased to the minimum turbine load, although the turbine would be spinning and a load increase could then be achieved fairly rapidly.

If a flue gas condensation system is used with the main boiler operated in part load the power production can be increased by by-passing the flue gas condensation, which shifts more of the heat load to the boiler. The cost impact is a loss of efficiency for a higher power production.

Another means of allowing an increase in the power output is to use extraction-back-pressure-condensing, or a back-pressure-condensing turbine combination instead. This is sometimes done

for redundancy purposes to support the grid. The condensing stage could then be added either when an existing turbine is replaced, or as a separate stage integrated with the main turbine and generator via a clutch and gear-box, or as a separate unit connected to the backpressure turbine via a steam pipe.

A completely fixed system requires steam flushing at all times, which introduces a continuous loss. A separated system would then require time (hours) to start-up. The potential effect of all steam being routed through the condensation stage is to increase the power output (also the efficiency to power) by 20-30 %, the lower number reflecting an already advanced steam cycle at high pressure and reheat while the higher number is for a smaller unit with lower pressure. However, at part load when back pressure steam is used for heating, the efficiency would go down more than proportionally.

On a marginal basis, if the design is for an excess steam capacity of, for example, 10 % of the live steam, this would mean a 13-15 % increase in power generation for the entire turbine complex, the higher number applying to a low power to heat ratio system, and the lower figure to a high power to heat system. To make such an addition worthwhile would mean that the plant is so large that a condensing stage gives a significant addition in MW and that there is some excess of steam available for a fairly large part of the operating time. For a given heat load, the production of additional steam requires more fuel when there is no excess, i.e. the marginal production cost becomes similar to a condensing plant and the fixed cost of the investment must be spread over the operating hours. This is attractive mainly for large plants, and where the value for additional power is high for a fairly large fraction of the operating period. This is also more suitable where the market is more oriented towards a mixed energy and capacity market instead of an energy market.

The installed capacity at present in Sweden in district heating plants, including waste incineration, is 3.6 GW, with an annual production of 9.2 TWh in 2013. This is expected to increase to around 4.7 GW by 2030[74].

Modulation of the power generation in a CHP district heating system

A district heating system is not typically served by a CHP boiler alone. It usually also contains other production units that are used for base-load, peaking or redundancy purposes, or to take advantage of waste heat that is available or of opportunities where power prices are low. Therefore, the global operation is controlled by an optimization model to ensure that the heat demand is met by the appropriate production units in terms of marginal pricing, as exemplified by Figure 14.

[74] Reglering av kraftsystemet med ett stort inslag av variabel produktion, NEPP, Mars2016

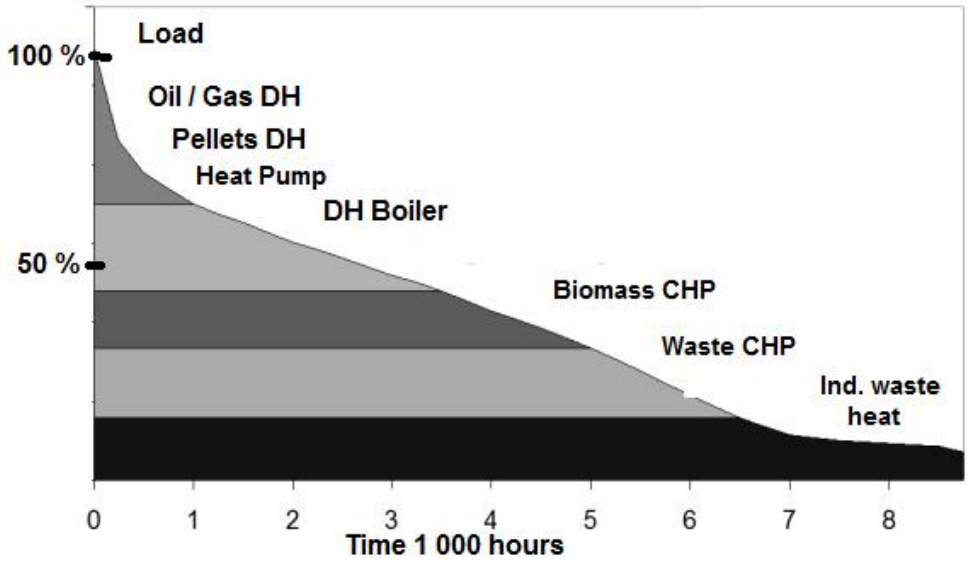


Figure 14 Example of district heating system load curve

Waste incineration, when used, is typically used as a base load as wastes are produced throughout the year. Waste heat from industrial activities, when available, also contributes to the base load and therefore the operational room for a CHP plant is reduced. To complement such units, there are in addition other units such as heat-only boilers fired with other fuels such as forest residues, wood pellets, bioliquids and fossil oil, as well as heat pumps to capitalize on cheap electricity.

This more flexible system can be used to decouple the CHP boiler from the heat load demand and allow the production of more power than is dictated by the heat load alone.

To increase the power output above what is dictated by the heat load, there are several ways. One of the main ways is to introduce an additional heat load. Connecting industrial facilities, either for district heating or for providing steam directly is often used when suitable. This generally requires a plant location that is relatively close to the industry in question to be feasible. One method of maintaining load in summertime is to provide district cooling by means of absorption refrigeration units. Another load with little variation over the seasons that has been discussed is desalination of water for e.g. island communities.

Another method is to introduce an artificial increase in the heat load. In many district heating plants, especially at larger capacities, return flow cooling is used, i.e. the district heating return water is cooled, in parallel with the other heat consumers, in heat exchangers that are cooled by sea, lake or river water, such that the heat load seen by the boiler is increased. This obviously introduces a higher fuel usage and a loss of efficiency that has to be added to the cost of the marginal power production.

Another way of increasing the heat load is to use an accumulator[75, 76]. Accumulators are large vertical (to prevent the internal mixing of the colder and hotter water) steel tanks, each up to

---

[75] Säsongvärmelager i kraftvärmesystem. Rapport I 2008:1. H Zink *et al*. Svensk Fjärrvärme

[76] Background Report on EU-27 District Heating and Cooling Potentials, Barriers, Best Practice and Measures of Promotion. D Andrews et al. JRC Report EUR 25289 EN, 2012.

15,000 m^3 for pressurized operation and up to 50,000 m^3 for atmospheric operation (30-35 m diameter, 60-70 m high and with a heat storage capacity of up to 2,000 MWh in the latter case). The filling or discharge takes between 4 and 24 hours, the typical design being use during the morning peak and refilling during the day to cover for the evening peak followed by refilling at night time, or alternatively discharging during the daytime including the peaks and refilling at night. A large tank could have a fill/emptying rate of, for example 100 MW, in a large plant and this would allow some 50 MW electricity during a period of several hours with retained efficiency over a longer period. Accumulators are already in use in district heating plant as they can allow operation above the minimum load at night, thereby avoiding shut-downs and use of heat-only boilers which often use more expensive fuels.

Even larger storage capacities have been considered in underground facilities such as pit ponds, rock caverns and in aquifers. In these cases the purpose of the storage is to provide cover for seasonal variations e.g. in the case of solar heat systems. Storage can also even out the CHP plant heat load over the year, avoiding using more costly fuel for winter peaking. The Avedoere plant in Copenhagen can charge or discharge 330 MW from its 44,000 m^3 pressurized storage, i.e. for this large plant the impact on power generation would be of the order of 200 MW.

Where an accumulator is available, it could also be used as heat supply that could be discharged in combination with an operating boiler on part load for a period of several hours. Alternatively the boiler could be operated at MCR load and could recharge the accumulator. For larger installations the impact could be significant. The Avedoere plant in Copenhagen can charge or discharge 330 MW from its 44,000 m^3 pressurized storage[76], i.e. for this large plant the impact on power generation would be of the order of +/-200 MW.

In many district heating systems there are also electrical boilers and large heat pumps. In Sweden there is in total 500 MW of load connected to each of these types of heat generator. Electrical boilers can be of a significant size, several tens of MWs, and heat pumps can also be of an electrical capacity of up to 10 MW. Several heat pumps can be operated in parallel to give good flexibility. Heat pumps can be very suitable in combination with district cooling supply. The largest heat pump installation in gross heat produced is in Helsinki, where five 6.5 MW heat pumps can provide up to 90 MW to the district heating grid in wintertime. Stockholm also has several heat pumps.

Where low cost electricity is available, electrical boilers and heat pumps can be used to supply heat to the grid and thereby reduce the output of a CHP plant. In a power surge situation in the spring or autumn, the impact can be significant as there is a leverage effect from switching from thermal generation to electrical supply. As an example, a 10 MW electric boiler will draw this amount from the grid, while a CHP plant can reduce in heat load by a corresponding amount. Depending on the system and the position on the load curve, the production of an additional 3-6 MW electrical is avoided. For a heat pump which typically has a COP of 3, 10 MW consumed results in 30 MW heat, and a CHP system can reduce in load to reduce the power output by 9-18 MW.

As most other demand side measures typically only give a 1:1 response, a leverage effect in the response by a factor of 1.3 to 1.8 could be very valuable. The other side of the coin is however that if large heat pumps are installed, they will also be used because the marginal cost for providing heat can then be relatively low compared to e.g. fossil oil. In this way, the power demand is affected.

Conclusions on bioenergy in CHP

A CHP system adds synchronous generators to the grid, which in itself is a stabilizing factor. It can

also contribute to primary frequency control but its importance is limited relative to other and larger generators in the grid. CHP boilers have the same limitations as other steam turbine based systems, e.g. load rate change is of the order of a few % per minute and secondary control is therefore also limited, particularly in relation to larger units on the grid.

The power output from a CHP system is controllable, but CHP plants are primarily operated to provide a heat load. Special measures are required to change the power output without affecting the heat load, which in many cases increase the marginal cost of electricity. However, district heating systems typically contain other components such as heat pumps and accumulators, as well as CHP and heat only boilers, and this provides more technical flexibility. Such combinations have potential for both generation and demand side interaction to control the energy balancing, if the entire span were available for balancing purposes.

In spite of this, the potential for CHP particularly as a means for grid balancing in district heating is limited. One period with particular strain for the grid system is the combination of high demand (wintertime) and low production of variable power. This typically coincides with the high heat load period when CHP plants are typically operated at full load leaving little control margin available and where the use of heat pumps affects the demand side negatively. The other difficult period is characterized by low demand (summertime) and high production of variable power. This second case coincides with the summer season standstill of CHP capacity when industrial waste heat and waste incinerator heat covers the base load such that the technical and economic potential of using heat pumps etc. is low, even in spite of low power prices.

In addition to such technical issues, there are also issues with the incentive and tax systems that act against the use of CHP for balancing purposes such as;

- minimum bid size for balancing power can be too high and automatically exclude smaller plants (min bid 10 MW using 10 % control margin requires a 100 MWe CHP plant)

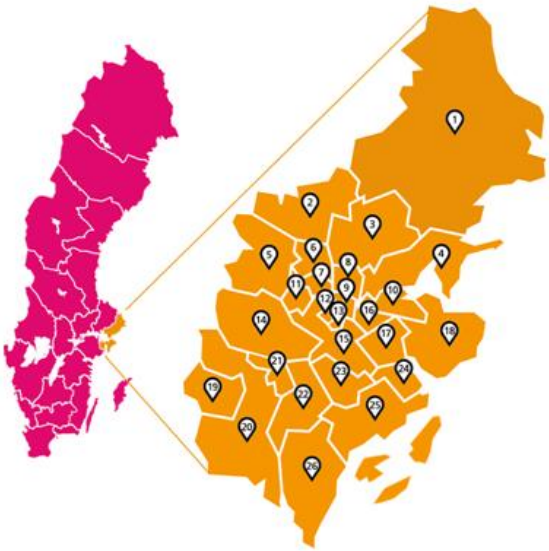
- certificates or feed-in tariffs give no incentive to reduce cost

- taxation of electricity use and other surcharges means that electric boilers cannot compete with other forms of heat even if the grid cost is low.

- at peaking, the cost of fossil fuel can be so high that the use of electricity is always favoured for heat pumps.

The CHP System in Stockholm

The Stockholm region, Figure 15, is located to the north and south of the outlet of lake Mälaren to the Baltic, the outlet also being the centre of the Swedish capital, Stockholm. The region is composed of 26 independent cities and communes and held 2.2 million people in 2015, or 23 % of the Swedish population.



		Population 2015
1	Norrtälje	58 478
2	Sigtuna	44 599
3	Vallentuna	32 364
4	Österåker	41 944
5	Upplands-Bro	25 691
6	Upplands Väsby	25 691
7	Sollentuna	70 062
8	Täby	68 015
9	Danderyd	32 469
10	Vaxholm	11 402
11	Järfälla	72 244
12	Sundbyberg	45 761
13	Solna	76 063
14	Ekerö	26 915
15	Stockholm	923 158
16	Lidingö	46 245
17	Nacka	97 808
18	Värmdö	40 997
19	Nykvarn	10 079
20	Södertälje	93 076
21	Salem	16 398
22	Botkyrka	89 374
23	Huddinge	104 999
24	Tyresö	46 019
25	Haninge	83 492
26	Nynäshamn	27 439

Figure 15 The Stockholm region (adapted from[77, 78])

All of these have to a larger or smaller degree a district heating grid network and there are also some major grids that serve several municipalities and urban centres, Table 6. The main operators are Fortum Värme followed by Södertörns Fjärrvärme and Vattenfall.

Figure 16 shows the extent and planned future changes to the regional district heating network. The central areas are already connected to the main grids (Central, West, Stockholm South, South, and South East) and additional areas with individual houses are being connected. The municipalities north and east of Stockholm are also exploiting new areas for housing and also connecting older housing areas.

The grids are also being increasingly interconnected to make better use of the heat production and improve the possibilities for CHP. The South-East and Stockholm South grids have an interconnection, as have both the Stockholm central and Stockholm South and the West and Stockholm Central grid. More recently the Stockholm South and the South grids have also been connected.

There were six CHP plant sites, Brista, Högdalen, Hässelby, Igelsta, Norrtälje and Värtan, (some of which hold multiple units) in the system in 2010 and also CHP plants in planning (Hagby, Högantorp, Jordbro, Lövsta Norrtälje and Värtan) of which two (Jordbro and Värtan) have been built since 2010. The new plants at Värtan, replacing the coal fired PFBC units, and Lövsta replacing Hässelby when built, are such that in total there will be nine CHP plants when and if all plants are developed. Of these there are waste incinerators on three sites (Brista, Högdalen and Igelsta) and another waste incinerator site, Högantorp, is in planning.

[77] www.sll.se

[78] SCB (Statistics Sweden)

The grid supply is also supported by several heat only boilers in various locations that, unless they are located in separate and smaller grid areas, typically are operated for limited periods of the year or serve as redundant units which are only used in contingencies. The fuels used are fossil oil, various bio-liquids (tall oil pitch, straight vegetable oil etc.) and wood pellets. In addition there are several large heat pump installations operated by Fortum and Norrenergi in the grid network.

Table 6 Stockholm regional district heat (DH) and CHP power production 2014 , grid system[79]

Grid Operator	DH GWh	CHP GWh	Cities and communes	Grid
Fortum Värme	6 441, 13, -, -	893, -, -, -	Stockholm, Lidingö, Solna, Täby	Central, Sthlm S
	6		Nacka	Stockholm S
	82		Nynäshamn	Nynäshamn
	577, 14, -	122, 0, -	Sigtuna, Upplands Väsby	West
Norrenergi	18, 4		Solna, Sundbyberg, Danderyd	Central
Dalkia	6		Lidingö	Sticklinge
			Ekerö	Dalkia
			Täby	Näsby Park
EON Värme Sverige	270		Järfälla	West
	48		Upplands Bro	Kungsängen-Bro
	71		Vallentuna	Vallentuna
	25		Vaxholm	Vaxholm
	70		Österåker	Österåker
Norrtälje Energi	170	22	Norrtälje	Norrtälje
Sollentuna Energi			Sollentuna	Sollentuna
Södertörns Fjärrvärme	137, 31, -		Botkyrka, Huddinge Salem	South
Telge Nät	2377, -	553, -	Södertälje, Nykvarn	Telge Nät
Vattenfall	603, 8, -	110	Haninge, Tyresö, Nacka	South-East
			Värmdö	Värmdö
Reported total	11 956	1 700		

[79] SCB (Statistics Sweden)

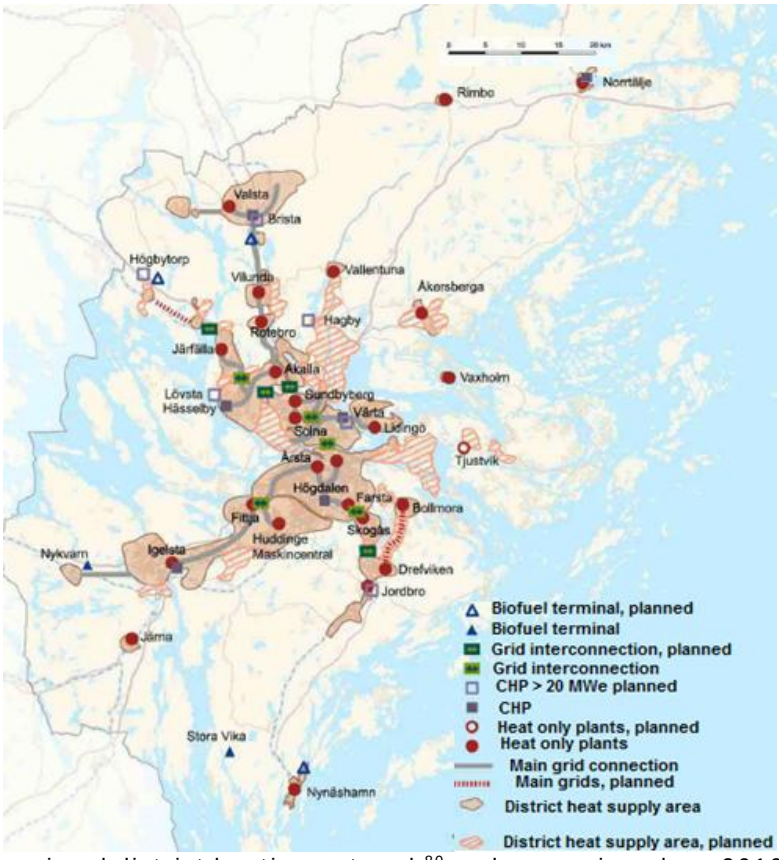


Figure 16 The regional district heating network[80] and expansion plans 2010.

Fortum Värme

Fortum Värme is a company jointly owned by the Stockholm municipality and Fortum Company of Finland. The grid network and main production units are shown in Figure 17

[80] RUFS 2010. Regional utvecklingsplan för Stockholmsregionen. SLL

Figure 17 The Fortum district heating system in Stockholm and vicinity[81]

The production in 2015[82] was 6.63 TWh district heat, 0.37 TWh cooling and 1.35 TWh power. The fuel used, Figure 18, is a mixture of coal, wastes and bio-energy fuels in combination with the upgrading of low-level heat sources by heat pumps. The City council have decided that the use of coal should be phased out by 2020. The production of heat uses less fossil fuel than the production of power, but this arises from a regulatory and tax allocation of fossil fuel to power.

[81] http://www.fortum.com/countries/se/foretag/fjarrvarme/har-finns-vi/pages/default.aspx

[82] Fortum Värme Annual Report 2015.

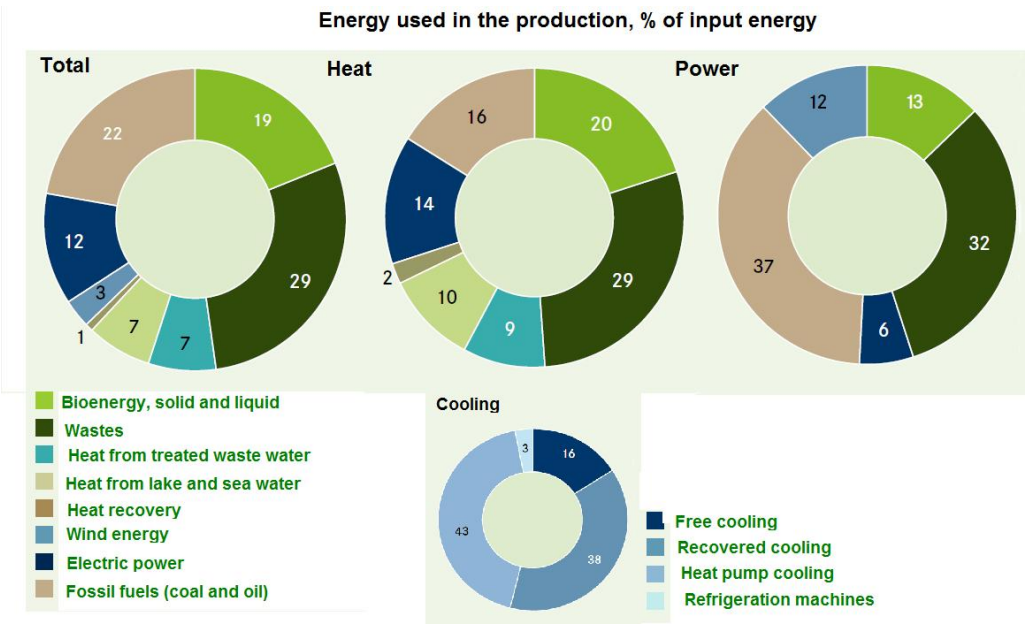


Figure 18 Overview of fuel usage 201582

The combined Stockholm central, south-east and west grid load curves, with the addition of the most recent plant, KVV8 at Värtan, Figure 19, shows that the base load is provided by waste incineration at Högdalen and Brista. In the central south system, today the PBFC (pressurized fluidized bed combustion) units at Värtan firing coal, being replaced in the future by the new biomass CHP plant, comes in at mid-merit. The next stratum is heat pumps both at Hammarby and at Värtan. For shorter periods pellets and bio-oil are used, typically in equipment originally designed for fuel oil, while fuel oil is only used for peaking.

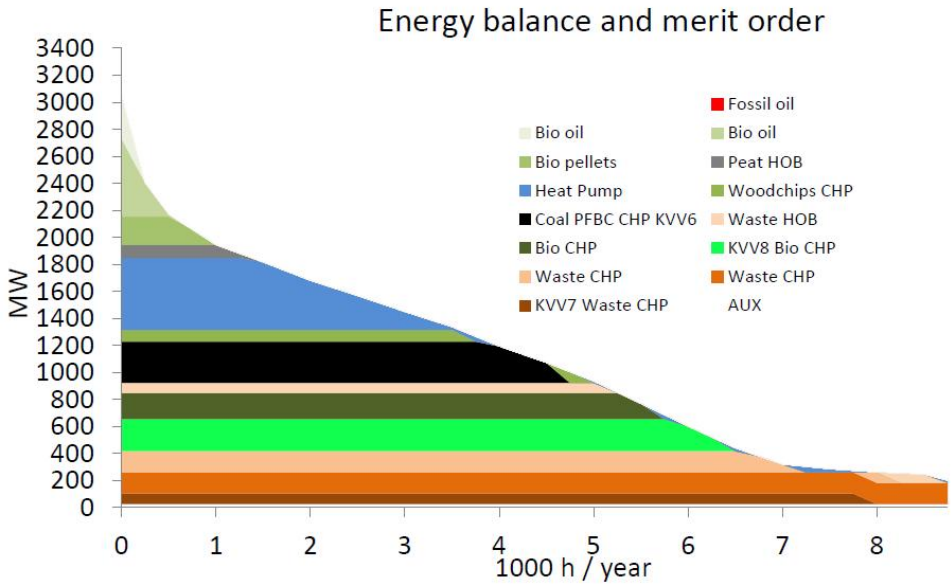


Figure 19 Overall load curve for Stockholm[83]

[83] Market reaction to economic climate change policy, the merit order effect and the limits of marginal abatement cost curves – Fabian Levihn, Royla Institute of Technology.

The Fortum production units

The production units in Stockholm, Table 7 have evolved since the Värtan site was established in the late 19th century, at the time fairly remote from the city but located in a harbour area where both power plants and a gas work were established.

The city has gradually moved closer, the harbour activities have also expanded and road infrastructure has been constructed. The site itself has expanded, with large oil CHP boilers added in the 1960's, some of which are still in use for peaking and as back-up. This was the first site for two commercial size PFBC plants (KVV6) commissioned in 1990, which are still in operation and are the only remaining coal fired plants in Sweden. As coal feeding is as a slurry, the flue gases are quite moist, with the result that these plants were retrofitted with a flue gas condensation unit around 2010. The expansion of the Värtan site also includes the heat pump and cooling installations at nearby Ropsten, and in 2016 the new FB boiler (KVV8) supplied by Andritz was commissioned.

The next site to be exploited was at Hässelby in the 1950's, at a time when the area was developed in the post-war era. It is located on lake Mälaren allowing both coal and oil to be shipped in. In the late 1980's firing wood pellets was tried, and gradually all three CHP units were converted in the beginning of the 1990´s. However, the plant is now seen as old and there are plans for a replacement at nearby Lövsta.

On the south side of lake Mälaren, which was also being developed after the war and in the 1960's and 70's, there were some oil fired heat only units in addition to heat supply from a heat-only prototype nuclear reactor at Ågesta (and plans were made for a larger underground installation at Värtan).

However, in the 1970's there was a need to improve the waste management situation while also increasing heat supply in the southern part of the city. Högdalenverket, which is 7 km from the city centre, was established for this purpose,. Since then, it has grown in scale to a complex where 300,000 tonnes of waste is incinerated annually. However even if some of the initial boilers installed have been phased out and new units installed, the need for incineration capacity has increased. It is planned to build a new incinerator as a replacement while increasing the waste capacity to 500,000 tonnes per year.

Table 7 Fortum Värme main production units

Värtan	Type	Thermal power	Fuel
VV1, P11, P12 , VV2, P13, P14	Heat-only boiler	2*128, 2*178 MW (133 bio)	HFO, bio-oil)
VV3 P15, VV3 P17	Heat-only, aux. boiler	178 MW, 26 MW	LFO, HFO, bio-oil
VV4	3*Electric boilers	3 x 51 MW	Electric
KVV1	CHP (G1)	607 MW, (330 MW+210 MWe)	LFO, HFO, bio-oil
KVV6	2*PFBC, 2 GTs, 1 ST	454 MW (250 DH+145 MWe)	Coal, olive kernels
G3	Gas turbine	180 MW (54 MWe)	LFO
District cooling installation KA101, 102, 103 and 104	4*Heat pumps, cooling mach.	Summer:3 MWe/12 MW DC Winter:3MWe/6 DC+9 MW DH	Power+ return DC or sea water
RGK - KVV6	Heat pumps	6 MWe gives 50 MW heat	FG condenser
KVV8 (2016)	FB boiler	330 MW (200+80MW+130 MWe)	Forestry waste FG cond. 80MW
Accumulator	Accumulator	40 000 m^3 (2GWh)	
Ropsten	**Type**	**Energy input/output**	**Energy sources**

VVRn1, 2, 3	Heat pumps (6+4)	6*8,4 MWe 24-27 MW DH 4*9.3 MWe 25 MW DH	Power, heat from sea water
EP 21-22	Electric boilers (2)	40 + 40 MW	Power
District cooling	Cooling unit	Approx 74 MW cooling	Sea water
Hässelby	Type	Thermal power	Fuel
VV1 , P1, P2, P3	PF	3*100MW (66+25 MWe	Wood pellets
VV2 (Mothballed)	Steam boiler	160 MWe	HFO
Högdalen	Type	Thermal power	Fuel
P1, P2, P3, P4	Grate boilers	2*23, 40, 82 MW	Wastes
P5		80 MW	Bio-oil, LFO
G1	ST turbine	27 MWe	
P6	CFB	91 MW (40 MWe)	Recycle fuels
RGK P1-P3, RGK P6		12 MW, 17 MW heat	Flue gas condens.
ERP 21	Electric boiler	25 MW	Power
Accumulator	Accumulator	900 m^3	
P7 (in planning)		500 MW	
Brista	Type	Thermal power	Fuel
Brista 1	CFB	42 MWe, 108+30 MW heat	Forest residues
Brista 2	Grate boiler	20 MWe +60+12MW heat	MSW
Hammarby	Type	Thermal power	Fuel
OP1, OP2	Heat-only boiler	2* 80 MW	Bio-oil
Electric boilers	Heat-only boiler	2*40 MW	Power
Heat Pumps	Heat pump	25+4*30+2*40MW	Power+WW
Cooling unit	Cooling unit	23 MW	Heat pump cooling
Accumulators		2*2 400 m^3	

The Brista plant was established in the 1990's in order to supply heat to the increasingly populated area to the west of Stockholm, and to also include others such as the nearby Arlanda airport and service areas. It replaced a number of large, oil fired units that are now mainly used for peaking and back-up. To increase waste management by incineration on the north of Lake Mälaren also, the second plant was built and commissioned in 2013.

The most recent major site to be established is at Hammarby in the south-centre of Stockholm. This happened in the 1980's and coincided with the refurbishment of a harbour and industrial area as a residential area. It is one of the largest heat pump installations in the world and benefits from the heat in the treated wastewater from the nearby Henriksdal wastewater treatment plant. The site retains some boiler installations for mid-merit and peaking in wintertime.

There are also a number of other installations comprising a heat-only 20-75 MW boiler firing bio-oil and HFO, electric boilers and heat pumps at Farsta and Alkalla, as well as a number of other heating boilers at Skarpnäck, Vilunda, Liljeholmen, Bredäng, Ludvigsberg, Årsta, Rotebro, Falken and Galten in Täby, where oil is used in capacities up to 20 MW.

Other leading operators in the Stockholm region

Vattenfall

Vattenfall has a 20 MWe wood-fired CHP at Jordbro in the southern part of the region as well as heating plants at Bollmora, Fisksätra, Nacka and Gustavsberg. It also supplies Nacka together with Fortum Värme.

Norrenergi

Norrenergi is the energy company of Solna and Sundbyberg, two populous towns neighbouring Stockholm. The company has eight large heat-only boilers using wood pellets and bio-oils and four heat pumps.

Söderenergi

Söderenergi is located in the town of Södertälje some 35 km south of Stockholm, and supports the south grid. It has an 85 MWe CHP plant, firing forest residues and recycled wood. There are also a number of heat-only boilers firing wastes at Södertälje in addition to those firing bio-oil, pellets LFO and HFO at other locations in the grid closer to Stockholm. The South grid is also connected to the Stockholm South grid.

FUTURE TECHNOLOGY AND MARKET OPTIONS FOR BIOENERGY CONCEPTS

Biomass and derived bioenergy carriers are storable and could technically provide energy on demand. This characteristic is especially relevant in energy systems with high shares of fluctuating renewable power, such as wind and solar. Provision of bioenergy is possible through various different pathways: thermochemical, biochemical, and physicochemical conversion systems are possible routes generating solid, liquid, and gaseous fuels which can then be employed to produce bio-based power. Biofuels can be upgraded and processed further, with examples such as product gas to synthetic natural gas ("SNG") or liquid biofuels ("bio-to-liquid"), vegetable oil to hydrogenated biofuels ("HVO") and biogas to biomethane. In theory pathways are possible from almost every resource to every energy carrier.

Using bioenergy systems for grid balancing is possible: in this context, bioliquids could play a major role. However, from a technical point of view, the application of bioliquid-based power systems has not yet been fully resolved, and therefore it still represents a technical challenge. Before examining the use of bioliquids, it is appropriate to analyse the technical options and typical intervention time of power systems in grid balancing mode.

Bioliquids as a storage means for balancing the grid

Bioliquids are derived from renewable feedstocks and used for stationary power generation. Electricity can be produced from bioliquids on demand (e.g. when the electricity demand from the grid is high), since liquid biofuels are easily storable and can be used in widely deployed and reliable energy system such as Internal Combustion Engines and Gas Turbine for producing heat and power.

Bioliquids are primarily produced to substitute fossil fuels for the transport sector but, due to their high energy density they represent a viable option for energy storage[84]. Adaptation of engines to different kinds of liquid biofuels has been investigated by several authors (such as Hossain et al[85]). Various concepts have been developed, even including combining micro-scale domestic biodiesel CHP system with hybrid electrical energy storage[86]. Thus, liquid bioliquids can provide flexible

[84] Thrän D, Dotzauer M, Lenz V, Liebetrau J, Ortwein A (2015). Flexible bioenergy supply for balancing fluctuating renewables in the heat and power sector—a review of technologies and concepts. Energy, Sustainability and Society, 2015, 5:35. DOI: 10.1186/s13705-015-0062-8.

[85] Hossain AK, Davies PA. (2010). Plant oils as fuels for compression ignition engines: a technical review and life-cycle analysis. Renewable Energy 35 (2010) 1–13. doi:10.1016/j.renene.2009.05.009

[86] Chen XP, Wang YD, Yu HD, Wu DW, Li YP, Roskilly AP (2012). A domestic CHP system with hybrid electrical energy storage. Energy and Buildings, Vol 55, pages 361-368. 10.1016/j.enbuild.2012.08.019#sthash.Qzw58zby.dpuf

power for a comparatively high number of applications.

Liquid Biofuels	*Energy density [kWh/liter]*
Pyrolysis Oil	5,9
Methanol	4,4
Ethanol	5,5
Vegetable Oil	9,2
Biodiesel	9,5

Technological Readiness Level of ICEs and GTs technology working with bioliquids

Given the particular grid-balancing operating mode, the technological status (TRL level) of the systems varies depending on:

- The type of bioliquids under consideration
- The type of power generation system (i.e. GT or Engine), and
- The desired type of reserve and supply

An estimation of the TRL level for various combinations of bioloquids and power generation/CHP systems under this particular type of use is given in the following tables. As already explained, a grid balancing system will have to respond very rapidly to changes of grid status, either from part-load conditions, stand by, or start-up: this has been carefully taken into account in the assessment of the combination of bioliquids and power generation systems.

As regards TRL, the following definitions apply, unless otherwise specified:

- TRL 1 – basic principles observed
- TRL 2 – technology concept formulated
- TRL 3 – experimental proof of concept
- TRL 4 – technology validated in laboratory
- TRL 5 – technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)
- TRL 6 – technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies)
- TRL 7 – system prototype demonstration in operational environment
- TRL 8 – system complete and qualified

- TRL 9 – actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space)

Fast Reserve (need good ramp rate)

	Internal Combustion Engine				Gas Turbine			
Technological Readiness Level (1-9)	R&D Trials (1-3)	Demo (4-6)	Qualified (7-8)	Commercial (9)	R&D Trials (1-3)	Demo (4-6)	Qualified (7-8)	Commercial (9)
PO		X				X		
VO				X			X	
ETH				X				X
Biodiesel				X				X

Note: To date, this has predominantly been achieved by controlling centralised power stations, in such a way that they maintain their connection to the grid but run at part-load. In this way they can rapidly respond to transients on the system network. However, maximum efficiency occurs at full-load, so operating a large central plant at part-load considerably reduces the efficiency of power generation, and the need for part-load operation may impact on the operational range of the power plant due to the need to comply with emissions legislation. In addition, cycling of the units, ramping up and down in load, can create the need for more frequent maintenance and power station outages. A large utility-scale turbine undergoing major maintenance can require around two to three weeks outage for disassembly, inspection, parts replacement and reassembly. Cycling also reduces part life and severely impacts plant economic returns and in some cases, overall viability.

Short Operating reserve (need both good ramp rate and start up) and Start Up (need short start up)

	Internal Combustion Engine				Gas Turbine			
Technological Readiness Level (1-9)	R&D Trials (1-3)	Demo (4-6)	Qualified (7-8)	Commercial (9)	R&D Trials (1-3)	Demo (4-6)	Qualified (7-8)	Commercial (9)
PO	X				X			
VO		X				X		
ETH				X				X
Biodiesel			X				X	

PO in Gas Turbine CHP Systems:

The production of biomass pyrolysis oil (PO) from lignocellulosic biomass achieved industrial demonstration scale in the EU, with a large industrial unit in operation. However, given the complex nature (acidity, viscosity, etc) of this bioliquid, PO is currently used only for industrial steam and heat generation, or burned in steam-based thermal power plant. It is not used yet in adapted high-efficiency internal combustion systems. Among the latter, the use of biomass pyrolysis oil in GTs could offer a number of considerable advantages compared to internal combustion engines. GT systems inject and burn the fuel in continuous mode (compared to the high frequency and short combustion time typical of IC-engines), so that combustion can be better adapted to unconventional and raw liquids. Re-design of silo-type industrial GT combustion chambers is possible, which greatly facilitates the use of PO. Compared to engines, GTs generally show good performances as regards pollutant emissions (CO, UHC, NOx and particles). GTs can deliver larger amounts of high temperature heat, suitable for industrial scale applications, and they are very compact and cost effective units. Various R&D and industrial groups have addressed this issue: industries like Orenda and OPRA have been working on the subject and solutions have been developed: it is reasonable to expect full-scale applications in CHP mode soon if the bioliquids become more and more available and economic conditions/policy is in place. However, operating a GT with PO in grid-balancing mode will still be a challenge, given the peculiar characteristics of the fuel and the time necessary to start-up and control the system to variable loads. Moreover, for the case of PO in an engine, the use of PO requires the installation of a third fuel line fed with a cleaning biofuel (most often an alcohol fuel). Multi-shaft GTs could offer benefits in this respect, given the higher control capability and part-load efficiency.

PO in IC-Engines

Diesel engines represent a very mature, widely available and proven technology, which can also be easily downscaled. A large maintenance infrastructure already exists worldwide, which facilitates the operation and servicing of the engine.

A large number of studies have been carried out since the early '90 by industries (such as Wartsila, Ormrod Diesel, Caterpillar, etc) on PO use in engines, including emulsions in conventional fuels or other fuel upgrading means. Recently BTG[87] tested a one-cylinder diesel engine modified to enable fueling with pyrolysis oil: the engine operated for 40 hours without any notable effect on flue gas emissions and fuel consumption, which represented a very promising result. In general, the following specifications should be met, at least for applications in diesel-engines[88].

- No solids in the bioliquid.
- Homogenous liquids. Water content of the liquid below 30 wt%. Single-phase liquid structure
- Good storage stability for at least 6 months. Viscosity increase maximum of 100% in
- the aging test ''24 h–80 1C'' (which correlates with the changes occurring during 1 year at

[87] Van de Beld B, Holle E, Florijn J (2013). The use of pyrolysis oil and pyrolysis oil derived fuels in diesel engines for CHP applications . Applied Energy, Volume 102, February 2013, Pages 190-197.

[88] Chiaramonti D., Oasmaa A. Solantausta Y. Power generation using fast pyrolysis liquids from biomass, Renewable and Sustainable Energy Reviews, Elsevier, 11 (2007) 1056-1086.

room temperature). Possible alcohol addition would support the fuel use.

Biodiesel in Gas Turbine:

The bioliquids with the most immediate and short-term potential for use in gas turbines are biodiesel and ethanol, due to their physical-chemical characteristics being very close to fossil fuels such as diesel or gasoline. Table 1 presents a summary of requirements for a liquid fuel as defined by the manufacturers of gas turbines for efficient operations[89].

Table 1 Requirement liquid fuel for gas turbines

Moisture and Sediment	1.0 % (v%) maximum
Viscosity	20 Cs at injector
Dew-Point	20°C at ambient temperature
Carbon Residue	1.0 % (P.) maximum
Hydrogen	11 % (p.) maximum
Sulphur	1 % (p.) maximum

As regards biodiesel, the fuel feeding system has to be adapted to meet the biofuel characteristics, such as the higher viscosity and the acylglycerols content, and to prevent possible corrosion effects[90]. In reality, the use of biodiesel in Gas Turbines has some effect on the GT feeding and combustion system, such as:

The higher viscosity of biodiesel leads to difficulties with its injection into the combustion chamber: it is possible to reduce the viscosity by increasing the temperature or by adding alcohols;

Accumulation of carbonized material in the inner parts of the gas turbine can occur;

Biodiesel could cause corrosion in the fuel feeding system;

It is recommended to install a filter of at least 50 μm in the fuel feed line;

Biodiesel has higher specific consumption than diesel, due to its lower heat value, thus more fuel is necessary for the same load.

Biodiesel in IC-Engines

The major fuel characteristics of biodiesel are similar to those typical of fossil diesel fuel: biodiesel is composed by alkyl esters of fatty acids, and the flash point, heating value, density and viscosity are comparable to those of diesel. This allows the use of biodiesel as a neat fuel for stationary

[89] Boyce, P. (2006). Gas Turbine Engineering Handbook. Third Edition, Gulf Professional Publishing . ISBN: 978-0-7506-7846-9

[90] Rosa Do Nascimiento MA, Cruz dos Santos E. (2011). Biofuel and Gas Turbine Engines, Advances in Gas Turbine Technology, Dr. Ernesto Benini (Ed.), ISBN: 978-953-307-611-9, InTech, Available from: http://www.intechopen.com/books/advances-in-gas-turbine-technology/biofuel-and-gas-turbine-engines

diesel engines without major modifications. Its additional advantages include outstanding lubricity, excellent biodegradability, superior combustion efficiency and low toxicity, compared to other fuels[91].

On the other hand the use of biodiesel as a bioliquid in stationary diesel engines for CHP applications is limited due to economic considerations, which drives the use of this biofuel towards transport. However, in light of grid-balancing mode of operation, it could be a very appropriate solution.

VO in Gas Turbines:

Various tests have been carried out with VO in GTs, such as Schmellekamp et al[92] who investigated a fully commercial gas turbine but did not address feeding at 100% VO, Prussi et al[94] who studied a 30 kW commercial GT fuelled at 100% sunflower VO, and Wendig[93] who studied the use of VO from rape, flax and waste oil in a small scale 75 kW_{el} gas turbine. A general conclusion was that VOs tested at full load showed increased CO emissions by a factor of 2.5–3 (compared to standard diesel oil), lower opacity and similar NO_x emissions. Vegetable Oil at 100% has been tested in a fully commercial system[94], which was adapted for the test with minor modifications to the fuel line. The experimental campaign confirmed that it is possible to operate a MGT fed with SVO through the adoption of minor modifications and by adjusting control parameters.

VO in IC-Engines

The use of pure vegetable oil as IC engine fuel substitute has been widely studied for a long time, and performances and emissions assessed even in agricultural based applications[95]. Today, VO in stationary diesel engines for power generation is a full and even large-scale industrial reality, with almost 900 MW installed in Italy only. These systems are normally run at design capacity-full load, as they receive support for the generated renewable energy.

Opportunities for using Bioliquids in Balancing the Grid

Liquid biomasses could thus be used for grid balancing purposes: a technical potential exist, both from feedstock availability and technical side.

Some bioliquids, as Flash Pyrolysis oil from biomass, could be largely produced in the EU without directly affecting the biofuel sector and competing in the food-feed markets. The potential for PO is probably the largest and most attracting option among the various form of bioliquids, as it can be obtained from woody or agricultural lignocellulosic feedstock. For instance, even considering EU waste and residual materials only, Europe generates approximately 900 million tonnes of waste paper, food, wood and plant material each year, among which 40 million tons of forest slash and 139 million tons of crop residues[96]. This material could effectively be converted into Flash Pyrolysis

[91] Balat M, Balat B. (2010). Progress in biodiesel processing. Applied Energy 87 (2010) 1815–1835. doi:10.1016/j.apenergy.2010.01.012

[92] Schmellekamp Y, Dielmann KP (2004). Rapeseed oil in a capstone c30. Workshop: bio-fuelled micro gas turbines in Europe. Available at: https://http://www.bioturbine.org/Workshop/PDF/4-Rapeseed%20oil%20in%20a%20Capstone%20C30.pdf

[93] Wendig, D. (2004). Biofuel in micro gas turbines. Workshop: bio-fuelled micro gas turbines in Europe. Available at: http://www.bioturbine.org/Workshop/PDF/3-Vortrag_Br%FCssel_eng.pdf

[94] Prussi M, Chiaramonti D, Riccio G, Martelli F, Pari L. Straight vegetable oil use in Micro-Gas Turbines: System adaptation and testing. Applied Energy 89 (2012) 287–295

[95] Balafoutis A, Fountas S, Natsis A, Papadakis G (2011). Performance and emissions of Sunflower, Rapeseed and Cottonseed Oils as Fuels in Agricultutural Tractors Engine. ISRN Renewable Energy, Vol 2011, Article ID 531510, 12 pages. http://dx.doi.org/10.5402/2011/531510

[96] Wasted-Europe's Untapped Resource. An Assessment of Advanced Biofuels from Wastes & Residues.

oil and be stored for its use in power generation system, even operating in Grid Balancing mode.

On the other hand, a considerable amount of pure vegetable oil (also named Pure Plant Oil) installations already exist and are in operation in the EU: more than 440 plants running on vegetable oil were existing in Italy only in 2014, totalling almost 900 MWe capacity and consuming approximately 1 million ton of vegetable oil per year (the largest share being imported palm oil). Nevertheless, lipid-based biomasses are mostly sent to transports, thus their adoption in this particular power generation market will only be possible if adequate policy and support mechanisms are in place.

While it is not economically sustainable to design, build and operate a bioenergy plant at a very low load factor, the use of existing (i.e. already amortised) installations that concluded the period in which they were benefiting from the different type of incentives and support mechanisms available in the EU could be seen as an opportunity to keep these alive and running. This would allot to supply of renewable energy for balancing purposes.

However, it has to be remarked that retrofitting and operating these plants to flash pyrolysis oil will require a significant effort in technological development, while the utilisation of pure plant oil would not imply the same R&D work.

Plug-in Hybrid Electric Vehicles *(PHEVs)* for Grid Balancing

Plug-in Hybrid Electric Vehicles (PHEVs) combine a gasoline or diesel engine with an electric motor and a large rechargeable battery. Unlike conventional hybrids, PHEVS can be plugged-in and recharged from by the grid, allowing them to drive extended distances using just electricity. When the battery is emptied, the conventional engine turns on and the vehicle operates as a conventional, non-plug-in hybrid. PHEVs generally have larger battery packs than hybrid electric vehicles.

Plug-in vehicles of all kinds – whether pure battery electric vehicles (EVs), range extended electric vehicles or plug-in hybrid vehicles – represent a potential opportunity for grid balancing. With appropriate control of a large pool of vehicles, the net power flow within the grid can be influenced with a similar effect to that of conventional balancing measures, presented in the previous section.

PHEVs that are in use at the moment can be seen as additional electricity consumption units and thereby an extra load on the grid, which can potentially cause problems mainly in the distribution grid. In a research carried out by EA Energy Analyses and published in “Grid integration of electric vehicles”[97] (Wu, 2013), the effect of a 25% electrification of the Danish personal vehicle fleet on the distribution grid is analysed. It is concluded that, when the charging is not managed, a high PEV penetration may cause problems in the distribution grid. However, if charging is done in a smarter way, more than 3.5 times more PEVs could be incorporated in the distribution grid. The following figure shows the electrical load on the distribution grid assuming 75% of the PEVs fleet start charging when back home from work (graph on the left, additional load), as well as the load in case the same charging load is spread over the night hours (graph on the right).

[97] Wu, Q. (2013). Grid integration of electric vehicles in open electricity markets. ISBN: 9781118568040. DOI: 10.1002/9781118568040

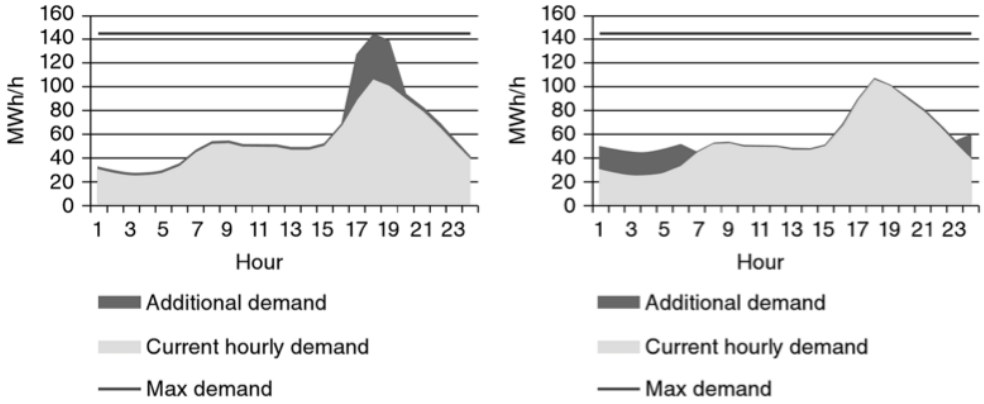


Figure 2 Effect of charging on the distribution grid with 25% of the Danish personal vehicle fleet electrified[97]

Controlled charging can thus be moved to periods of higher variable-generation, while charging rates can be controlled to provide contingency reserves or frequency regulation reserves (DSM Approach). Vehicle-to-grid (V2G) (where EVs can partially discharge stored energy to the grid) may provide additional value by acting as a distributed source of storage. Most proposals for both controlled charging and V2G focus on short-term response services such as frequency regulation and contingency[98]. Indeed, in the case of grid balancing by plug-in vehicles, charging power can be varied relatively rapidly compared with typical generation plant, making participation in "response" balancing services particularly attractive for PHEVs. On the contrary, the likely limitations of charger power, flexibility over timing and energy storage capacity would make "reserve" balancing services less appropriate for plug-in vehicles, although participation could be possible to some extent.

The role of V2G is an active area of research, and because EVs in any form have yet to achieve significant market penetration, assessing their potential as a source of grid flexibility is difficult[99]. However, studies demonstrated potential system benefits of both controlled charging and V2G[100, 101], particularly with a case study in Denmark[102].

Ricardo[99] investigated whether a future fleet of plug-in vehicles (PIVs) could help to support an electricity grid that will require an increasing level of balancing services, taking as an example the GB National Grid.

In its analysis Ricardo performed two distinct modelling works to analyse the opportunity for grid balancing from two different viewpoints:

---

[98] Augustine, C, Bain R, Chapman J, Denholm P, Drury E, Hall DG, Lantz E, Margolis R, Thresher R, Sandor D, Bishop NA, Brown SR, Cada GF, Felker F, Fernandez SJ, Goodrich AC, Hagerman G, Heath G, O'Neil S, Paquette J, Tegen S, Young K (2012). Renewable Electricity Generation and Storage Technologies. Vol 2. of Renewable Electricity Futures Study. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory. Available at: http://www.nrel.gov/analysis/re_futures/.

[99] Ricardo and National Grid (2011). Bucks for Balancing: Can plug-in vehicles of the future extract cash - and carbon - from the power grid? Available at: www.ricardo.com

[100] Denholm P and Short W (2006). An Evaluation of Utility System Impacts and Benefits of Optimally Dispatched Plug-In Hybrid Electric Vehicles. NREL Technical Report NREL/TP-620-40293.

[101] Waraich RA, Galus MD, Dobler C, Balmer M, Andersson G, Axhausen KW (2013). Plug-in hybrid electric vehicles and smart grids: Investigations based on a microsimulation. Transportation Research Part C: Emerging Technologies, Volume 28, March 2013, Pages 74–86.

[102] Kop SN, Emmert Andrersen Zapata MK (2015). The Role of Plug-in Battery Electric Vehicles in the Danish Energy System: Model Study and System Design. Master Thesis, Aalborg University. Available at: http://projekter.aau.dk/projekter/files/213513909/The_Role_of_Plug_in_Battery_Electric_Vehicles_in_the_Danish_Energy_System_no_appendix.pdf

That of a grid operator service provider, covering the macro-level effects of a large number of vehicles in use with an assumed variation in recharging patterns across the entire PIV parc: the grid-level model

That of an individual vehicle user or owner, covering specific recharging patterns in order to investigate how revenue could be maximized: the individual vehicle model.

A clear potential for the commercial exploitation of a future fleet of electric plug-in vehicles in the provision of grid balancing services, while they are connected for the purposes of daily recharging, was estimated. Based on the simplest mode of service provision – that of demand-side management using a standard 3 kW domestic socket supply – the UK plug-in vehicle fleet in 2020 would be capable of providing a 6 % average of the country's predicted daily grid balancing requirement for the same year. This could be realized at zero investment cost and no inconvenience to the consumer, while providing a financial return that, while limited, represents the equivalent of 18 % of vehicle electric 'fuel' costs at current prices. Thus, this significant potential benefit to the grid represents a reliable justification for the establishment of "smart grid" infrastructure, which is already broadly regarded as a pre-requisite for widespread plug-in vehicle usage.

Biofuels could play a role in this context, as the engines would be fed with renewable fuels replacing conventional fossil fuels: the PHEVs fuelled with biofuels could, indeed, act in the same manner as stationary engines for power production when vehicles are plugged in to the grid for balancing the grid. As the combustion engine has to work for transport purpose also, the biofuels that could be used in this configuration are ethanol, biodiesel and biomethane.

Forecasted diffusion of PHEVs Vehicle

The year 2011 may well be remembered as the year when plug-in electric vehicles (PEVs) first became a common sight in automobile showrooms. However, despite high-profile vehicle launches, recent forecasts indicate that industry watchers may need to wait until the next decade before PEVs account for even one in 10 vehicles on the road around the world[103].

Recently, Bloomberg Energy Finances[104] estimated that by 2022 EVs will cost the same as their internal combustion counterparts, and that by 2040 EVs will represent 35% of all new vehicle sales. BEF modelled various scenarios for EV sales take-off: assuming the current growth rate, between 2023 and 2024 oil displacement would reach 2 million barrels per day.

Therefore, a future widespread diffusion of PHEVs, relative to full EVs, could also be expected, as PHEVs require limited changes to driving habits and demand less power from the grids. If consumers prefer not to change how they run and manage their cars, the popularity of dual-fuel PHEVs could hinder the adoption of full EVs[105].

The outcome of the battle between the two vehicle types will impact the investment decisions of

[103] J.D. Power and Associates, (2010). Future Global Market Demand for Hybrid and Battery Electric Vehicles May Be Over-Hyped,", PR Newswire, October 27, 2010. Available at http://www.prnewswire.com/news-releases/jd-power-and-associates-reports-future-global-market-demand-for-hybrid-and-battery-electric-vehicles-may-be-over-hyped-wild-card-is-china-105857988.html.

[104] Randall T (2016). Here's How Electric Cars Will Cause the Next Oil Crisis. Bloomberg Energy Finance. Available at: http://www.bloomberg.com/features/2016-ev-oil-crisis/

[105] Accenture (2011). Plug-in electric vehicles: Changing perceptions, hedging bets. Available at: https://www.accenture.com/us-en/~/media/Accenture/Conversion-Assets/DotCom/Documents/Global/PDF/Industries_9/Accenture-Plug-in-Electric-Vehicle-Consumer-Perceptions.pdf

electricity retailers, power generators and network operators, and determine the infrastructure they build, thus creating an opportunity for decision makers (grid operators, authorities, etc.) to build an integrated system, with PHEVs fleets, that could help with grid balancing.

Regarding grid balancing, a PHEV fleet could be managed by the operator in such a way as to balance the system while maintaining sufficient driving range in the hybrid mode for the user, until the tank can be refilled with biofuel. This outcome could be achieved without additional investments, but rather through optimising and increasing the load factor for technologies that are already being used. Another advantage of this option results from the fact that several small-scale hybrid engines physically parked near the end users could be very effectively integrated into smart energy concepts, where liquid biofuels could provide additional storage capacity and micro-power on demand.

A non-exhaustive list of PHEVs currently available on the market is as follows: Chevrolet Volt, Toyota Prius PHEV, Ford C-Max Energi, Ford Fusion Energi, Honda Accord PHEV, Audi A3 E-Tron, BMW i8, BMW X5 xdrive40e, Cadillac ELR, Hyundai Sonata Plug-in Hybrid, Porsche Cayenne S E-Hybrid, Porsche Panamera S E-Hybrid, Mercedes C350 Plug-in Hybrid, Mercedes S550 Plug-in Hybrid, Volvo XC90 T8, McLaren P1.

BIOFUELS AND ELECTRICITY

There is a potential synergy between many biofuels and the occurrence of low cost electricity. The electricity can be converted to hydrogen which is an immensely important chemical in both fossil fuel refining, chemical production and also for biofuels. If there is an excess of cheap electricity, this can be used for electrolysis of water to generate hydrogen and oxygen by water splitting;

$H_2O \rightarrow H_2 + 1/2O_2$ $\Delta H_r = 242$ MJ/kmol (steam), 286/MJ/kmol (liquid water)

The hydrogen can be used to replace fossil derived hydrogen in hydrogenation processes such as HVO, and processes in development for upgrading pyrolysis oil, HTL oil and lignin depolymerizates. Hydrogen can also be used to enhance biogas processes by conversion of the CO2 contained in the biogas to additional methane. In biomass gasification processes, hydrogen added means that the yield can be increased as hydrogen can, in the first instance, give the right stochoimetric ratio so avoiding loss of CO for water gas shift, and secondly also reduce CO2 to CO that can then be converted to additional products.

Production of hydrogen

The conventional way of producing hydrogen is by steam reforming of natural gas. The data for such units is 70- 80 % thermal efficiency and an investment cost[106] of 1.3-3 M€/MW product in the size range of 0.06 to 2.2 tonne/hr. The current natural gas price is 38 euro/MWh for industrial clients[107] and the O&M is 4 % of the investment. The energy cost is typically more than 50 % of the hydrogen cost, but at lower capacities the energy cost has less influence on the hydrogen cost.

Electrolysis has an efficiency of 60-65 % for state of the art (alkaline, PEM) technologies and is higher for technologies in development (e.g. SOE) with a cost of 0.6-1.6 MEuro/MW electric input,

[106] Own data, Hydrogen Station Cost Estimates Comparing Hydrogen Station Cost Calculator Results with other Recent Estimates. M. Melaina and M. Penev. Technical Report NREL/TP-5400-56412. National Renewable Energy Laboratory, USA, September 2013

[107] Eurostat

i.e. 0.9-2 MEuro/MW of product. A report[108] reviewing the subject has a figure of 1-1.2 MEuro/MW electric input. Since the electrolyzers have limited capacity per unit, a larger plant has more and more parallel cell stacks and the economy of scale is therefore not so pronounced. In this report other O&M costs were given as 1.5 to 4 %, depending on the capacity. In addition, the cell stacks, representing 25-35 % of the original investment typically have a lifetime of 7-10 years, i.e. they are replaced 2-3 times over a 20 year plant lifetime. The cost of the hydrogen produced is strongly influenced by the cost of electricity, but in comparison with SMR it can already produce lower hydrogen cost at smaller capacities. If electricity prices go down while the current low natural gas price goes up, the capacity boundary will shift towards higher capacities. In the future, the expectations are that for a greater part of the year, the cost of electricity will go down as a result of the addition of more wind and solar power production.

HVO

To upgrade the triglyceride fed to HVO, the hydrogen consumption is in the range of 3-3.5 % of the feed depending on the process and feedstock, and approximately 80-85 % of the feed comes out as fuel liquids. For a 100,000 tonne plant such as the UPM plant in Lappeenranta using Crude Tall Oil (CTO), and assuming a yield of 80 % and a hydrogen consumption of 3.5 % by feed weight, the hydrogen requirement is of the order of 0.55 tonne/hr. Based on a 50 MWh/ton electrical usage, the electrical consumption would be 27 MW to supply all the hydrogen. Significantly larger installations are planned or in operation on vegetable oil/lipids (as Crude Palm Oil): more than 2 Mtonne for Neste Oy, 500,000 tonne for Total in France, the ENI 560,000 tonne plant in operation at Porto Marghera, Venice, and by 2018 a second plant in Gela, Sicily.

Pyrolysis oil upgrading

Fast pyrolysis is a way of converting solid biomass to a liquid fuel, or “bio-oil”, that can substitute for other fuels in combustion applications. However, if a more valuable product is desired the bio-oil requires upgrading to allow its use as a drop-in hydrocarbon fuel.

One way of upgrading pyrolysis oil is by hydrogenation of the oxygen to steam, whereby the carbon yield is higher compared to the alternative, FCC route where oxygen and excess carbon is rejected as CO_2 and soot, respectively.

Typically pyrolysis oil contains a significant amount of oxygen. However some 5-30 % of the oil is water whose oxygen content does not consume hydrogen in the process. while the dry oil can hold 10-40 % oxygen. The lower numbers for water and oxygen represent oils from staged condensation and from catalytic pyrolysis, respectively. For example, the Joensuu plant, which produces 50,000 tons of bio-oil per year, requires approximately 0.2 tonne/hr hydrogen, or some 3 % by weight, to hydrogenate this bio-oil, and this equates to a 10 MW electrolysers.

Upgrading of HTL liquids or depolymerised lignin

For other forms of thermal treatment of biomass such as HTL and of biomass by-products such as lignin, a considerable amount of hydrogen is also required. HTL crude bio-oils typically hold 5- 12 % oxygen which would require 0.5-1.5 % hydrogen per kg of feed. Raw lignin holds approximately 30 % oxygen and unless treated by some intermediate de-polymerization/deoxygenation process, would require up to 4 % hydrogen.

---

[108] Development of Water Electrolysis in the European Union. Final Report. Fuel cells and hydrogen Joint undertaking. E4tech, Sàrl with Element Energy Ltd, February 2014

Upgrading of biogas

External hydrogen could be used to hydrogenate the CO_2 fraction in biogas, which is typically 40 %, to produce additional methane and save on the upgrading cost. This is being studied by the CO2 Electrofuels project funded by Nordic Energy Research, which claims that the methane output can be increased by 65 %, using SOE technology.

In 2013, there were some 14,200 biogas plants in Europe, producing 156 TWh, i.e. an average size of 11 GWh. To convert the CO_2 to an additional 7 GWh methane would require 20GWh electricity, i.e. a 2-2.5 MW electrolysers for an average such biogas installation.

Gasification-based biofuels

Gasification-based biofuels such as methanol/DME, bio-methane and FT diesel are all produced by conversion of the biomass to a synthesis gas, i.e. a mixture of CO and H_2. In the raw syngas, there are considerable amounts of CO_2 formed in the gasification process based on the biomass composition. This is later rejected in the syngas upgrading process in order to avoid diluting the syngas and interfering with the synthesis chemistry. As part of the biomass fuel is also used to provide the reaction energy, this gives additional CO_2 in the gas in an oxygen-blown gasifier. In an indirect steam gasifier, where sand is used as a heat carrier, carbon is instead lost being oxidized to CO_2 in the combustion chamber to heat the circulating sand.

Depending on the fuel produced, the stochiometric ratio of H2/CO should be 2, with the exception of methane where it should be 3. However, typical biomass gasifiers produce a gas that has a ratio of 1:1 to 1.5:1, such that the water gas shift reaction $CO+H_2O \rightarrow CO_2+H_2$ is required to convert some CO to hydrogen. This adds to the CO_2 already present in the gas, and typically the CO2 level is reduced down to levels of a few % by volume in the final gas. This implies that biogenic carbon is lost as CO_2, i.e. the carbon yield to biofuel is decreased. In the case of steam gasification some 25-30 % of all carbon entering the gasifier is lost in this way. Another similar amount is lost in the flue gas from the char combustion section, which means that more than half of the carbon does not end up in the biofuel product. For an oxygen blown gasifier over 50 % of the carbon is also lost but in this case predominantly as CO_2 removed from the synthesis gas.

If there is hydrogen available, this could have a considerable impact on the biofuel output. As an initial stage, the hydrogen could be partially of fully used to avoid the use of the water gas shift whereby some 30-50 % more CO could be converted to biofuels. For an indirect system this could mean 2-3 kg hydrogen/MW biomass feed, e.g. for the GoBiGas plant of 30 MW making bio-methane, up to 60 kg/hr of hydrogen or an electrolyser of 3 MW. For an oxygen blown gasifier the hydrogen potentially used is doubled, i.e. for a 200 MW unit 1-1.5 tonne/hr or 50-75 MW.

As a second step, the CO_2 in the gas can also be partially or fully hydrogenated to CO such that all biogenic carbon ends up in the product. The complete conversion has been studied by e.g. Hannula[109], who concluded that for an oxygen-blown gasifier of 100 MW, an electrolyser of 170 MW could be used, and for an indirect gasifier of 100 MW biomass feed, a 95 MW electrolyser could be used.

As a side effect the oxygen produced in the electrolyser could be routed to the gasifier and substitute for oxygen from an air separation unit.

---

[109] Hydrogen enhancement potential of synthetic biofuels manufacture in the European context: A techno-economic assessment Ilkka Hannula, Energy 104 (2016) 199e212

The overall gain of such systems is that more biogenic carbon is retained in the fuel product, with more substitution of fossil fuel equivalent. The marginal efficiency from electricity to biofuels for the complete conversion was found to be around 50 %, while for shift conversion only it is higher, at around 65 %, as less hydrogen is consumed per carbon atom in CO compared to CO_2.

Hannula also studied the economic impact and found that the average electricity break-even price was as low as 27-35 €/MWh for different configurations. The impact of the potential for generation of low-carbon fuels is also very high. The biomass and waste resources in the EU could theoretically be used as a basis for the production of half the transport fuels in the EU, compared to a less significant 10-20 % without this exploitation of synergies.

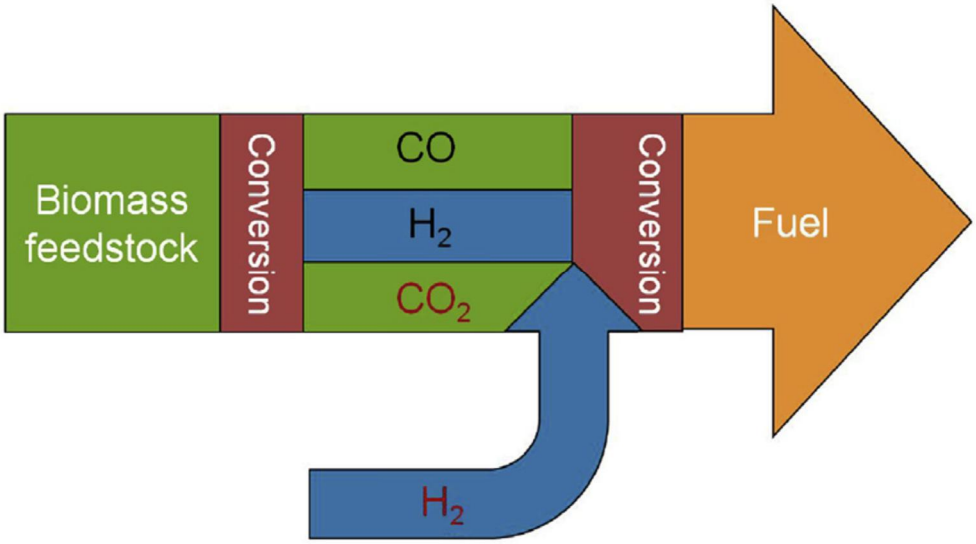


Figure 20 The principle of external hydrogen enhancement[110]

[110] Hydrogen enhancement potential of synthetic biofuels manufacture in the European context: A techno-economic assessment. Ilkka Hannula. Energy 104 (2016) pp. 199-212

Appendix 3 Technical grid balancing aspects

TYPES OF BALANCING POWER

Characteristics, classification, and nomenclature of balancing power vary across power systems. Since multiple sources of imbalances exist with different characteristics, several types of balancing power are employed simultaneously in most power systems. Balancing power types can be distinguished along several dimensions:

- purpose (operating/non-event v. contingency/event reserve)
- state of supplying power plant (spinning v. stand-by reserve)
- target system (synchronous system v. balancing area)
- response time (fast v. slow)
- activation frequency (direct/continuously v. scheduled)
- activation mode (manual v. automatic)
- positive, negative, or both (upward v. downward v. symmetric)'

The balancing power market

The balancing power market is a "tool" required for the maintenance of the power balance. Holders of capacity which can be regulated can submit bids for their available regulating capacity to this market.

A balancing market consists generally of two important parts:

- Balancing services procurement defines features of procurement processes, e.g. the way of bidding, constraints/ requirements on the balancing market participants, way of payment to the bidders, constraints on the TSOs, who/how makes the merit order, etc.
- Imbalance settlement scheme allows charging costs borne by a TSO to be passed on to entities responsible for balance .

THE ELECTRICITY MARKET[111, 112, 113]

The electricity market has a number of defined actors;

- Legislators are responsible for the legal framework of the electricity market
- Regulators have the role of supervising the electricity market to ensure that the technical standards are upheld, the transparency and governance of the market and its functions, as well as that the cost and fees paid by consumers are reasonable in relation to the costs

[111] Electricity Markets and Grid Services –Chances and Challenges for Communities. Thomas Erge, Thies Stillahn. Fraunhofer Institute for Solar Energy Systems ISE. July 2015.

[112] The Common European Energy Market. Vattenfall AB.

[113] The Nordic financial electricity market. NordREG Nordic Energy Regulators. Report 8/2010

of supplying energy and associated services.

- Generators produce the electricity supplied to the grid of mainly TSOs but also DSOs
- Transmission System Operators (TSOs) have a monopoly for transmission grid (joining generators and DSOs) operations in a defined area and bilaterally also for interconnections with other TSOs, but are also responsible for the grid operation and security of supply in their respective area.
- Distribution System Operators (DSOs) are responsible for the electricity distribution in a given area and ensuring that the energy sold by retail suppliers is transported to the end customers.
- Wholesale Market Place where generators, retail suppliers, TSOs and major industries meet to settle the price for the products necessary to operate the electrical system.
- Retail Suppliers who buy electricity on the wholesale market for supply to consumers on the retail market.
- Traders that buy and sell financial products such as futures, options and other structured products that may or may not involve a physical energy supply obligation.
- Consumers that are the end-customer of the energy system
- Demand-controlled consumers, i.e. consumers that have an agreement with TSOs to automatically reduce or shed load after a deactivation warning period (typically 15 min) as part of grid balancing (RR or BM)

As a result of the introduction and expansion of renewable energy, there are also other market actors that have come into the system recently;

- Aggregators that sell the combined generation products of a number of small-scale generators that on their own would be too small to engage on the market.

- “Prosumers” that are consumers that to a variable degree produce part, all or even an excess of energy on an annual basis.

In the past, under the regulated systems used, electrical companies would perform several roles on the market, such as being generator, TSO, DSO and retail supplier in one entity, and with prices being defined by a regulator. This system led to over-capacity, low drivers for rationalization, poor transparency and consumers with little influence. Deregulation has the purpose of increasing both the technical and economic efficiency of the supply of electrical energy. The main changes have been to introduce market trading and to unbundle the former electricity companies into entities with a clear and defined role and reimbursement modality on this market. However, retail suppliers may also still be generators. Market trading also means that the electricity market is based on marginal pricing, also referred to as the “order of merit”.

The wholesale market includes both OTC markets, where generators and major industrial consumers or retail suppliers contract supplies of electrical energy on a bilateral basis, and power exchanges such as Nord Pool in the Nordic regional market, EPEX in Germany and APX-ENDEX in the Netherlands, etc.

The main physical products traded are;

- Long-term trade over the market exchange
- Spot-trade, two-days-before or day-before market
- Intraday trade, i.e. supply within the same day
- Balancing Energy

There is also trading of ancillary services, e.g.;

- FRC
- FFR
- RR
- Other Reserves
- Reactive Power Control
- Reliability must run
- Black start capability
- Congestion management

In addition there is typically also trading of financial securitization instruments that are traded on separate but linked financial markets (e.g. NASDAQ OMX in the case of Bordpool) such as;

- Base load futures for months, quarters, years ahead
- Buy and sell options
- Peak load futures
- CfDs (Contract for Difference) reflecting the difference between the area price and system pool price.
- Certificates of origin
- Green certificates, ROCs etc.
- Emission trading allowances

The market structure is exemplified in Figure 21.

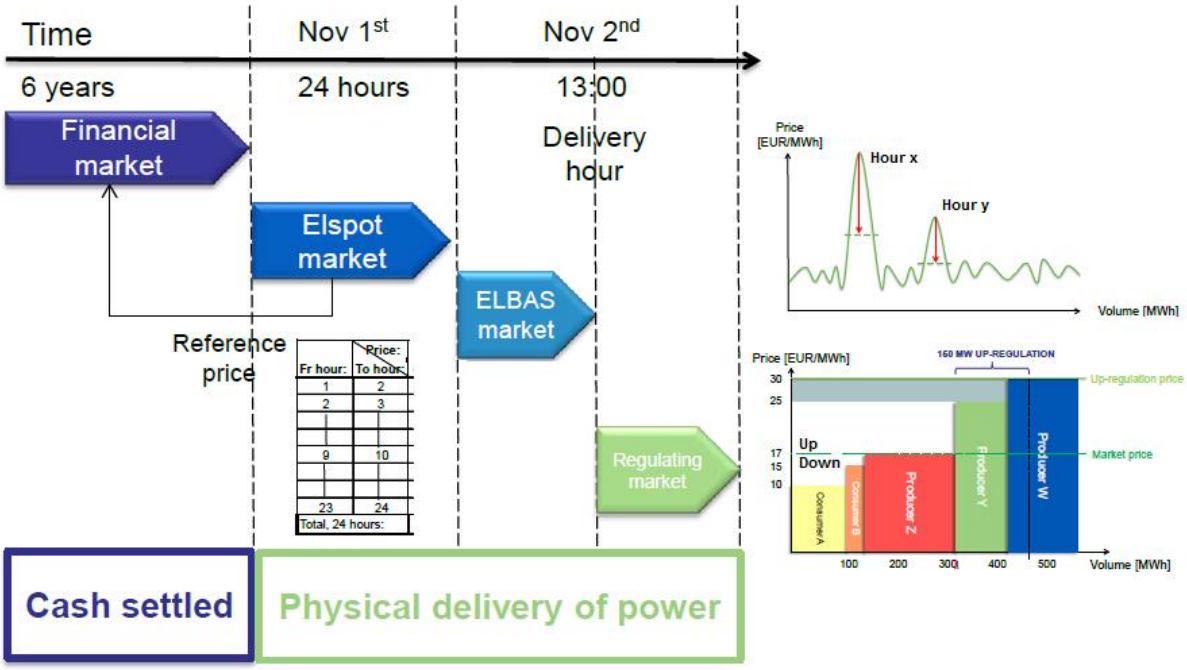


Figure 21 The electrical market place, Nordpool system (adapted from[114])

The OTC market is smaller than the exchange market (85-90 % is traded on the latter market in Nordpool). The majority of the electricity is sold on the spot market (over 70 % of

[114] THE NORDIC/BALTIC POWER MARKET Ellen Charlotte Stavseth Oslo, June 11th 2013.

the exchange traded electricity on Nordpool), the day before market. The generators or other suppliers e.g. HVDC operators, place bids for supply of energy in hourly slots before a defined time on the day before physical delivery. Buyers contract certain volumes by first selecting the lower priced products and then gradually buying products at increasing cost until the full demand is met. This defines the system or pool price. The different exchanges have different rules as to the minimum volume of a bid and this can range from 0.1 to 1MW in different markets with increments of 0.1 MW.

The intraday market is used to cover smaller variations in demand and supply not foreseen in the supply/demand forecasting. It trades in a similar way with hourly slots up to one hour before the physical delivery. There are also other products such as “ramps” (an increase in capacity in a ramp, a hold time at full volume and a ramp down) and “blocks” (payment for an instantaneous supply of full volume for a given hold time follow instantaneous interruption of supply, even if the physical supply includes ramps before and after the hold time). There is a process with ENTSOE-E to standardize such manually activated or pre-scheduled products (codes for volume, preparation period, activation time, hold time and deactivation time)[115]. The bid definition in terms of volumes on different market exchanges is typically identical with the bid definition on the day before market, i.e. from 0.1 to 1MW with increments of 0.1 MW.

A generator not fulfilling its position from the intraday market can either buy on the intraday market or pay an imbalance settlement.

The balancing power and ancillary services are procured by TSOs. This can include both generation capacity and demand control. The balancing market is bilateral between the TSO and another entity, and is also typically associated with stronger obligations and higher penalties if the contracted volume cannot be supplied on activation. The minimum bid volumes are in this case larger than on the spot market, from 1-5 MW for FRR, and 5-50 MW in both directions for balancing services.

Congestion management to overcome grid bottlenecks is managed by two primary methods: market splitting and counter-trading, as a nationally insular solution by decreasing cross-border trade is not in line with EU legislation.

Market splitting implies organizing different Control Areas with different market prices to capitalize on the lack of generation in one area causing compensatory demand for transmission. Counter-trading means that the TSO pays to reduce electricity production at one side of the bottleneck, and also to increase production at the other side of the bottleneck, such that the wholesale electricity price becomes the same in the regions on both sides of the congestion cross section. The first method stimulates investment on the deficit side while the other method allows the retail market to use one price only in both regions and the added cost goes to the grid tariffs in both regions. This means that the end users are not encouraged to either decrease or increase their electricity consumption, relative to the electricity retail price. Instead, congestion costs are transferred to the grid tariffs.

---

[115] ENTSO-E Standard products. March 2015.

There are also other services related in particular to renewable energies such as self-marketing on the basis of feed-in-tariffs, net metering, self-sufficiency and self-balancing. Such “Prosumers” reduce the electricity transferred in a DSO system such that more of the grid capacity can be used for balancing varying supply/load. Since self-sufficiency or self-balancing reduces the need for balancing power, this can be seen as an avoided cost to DSOs and TSOs.

THE TECHNICAL BACKGROUND TO GRID BALANCING

The balance and the margins for imbalance

The difference between electric energy and other forms of energy is that electricity cannot be readily stored in the grid; whatever is produced has to be consumed or diverted from the grid.

With the exception of most wind power and all solar power units where the conversion is electronic from variable speed or a DC/AC converter (however, such units are increasingly fitted with power electronics to mimic synchronous operation), the generators on the grid are all rotating synchronously at the nominal grid frequency and can be viewed as “motors”. The demand can also be rotating components such as motors, but also heaters, transformers and HVDC interconnections feeding energy into other grids, and can be seen as “brakes”. In the case where generation is in excess of the demand (more throttling than braking), the rotational speed, i.e. the frequency, will tend to increase, and with more demand than generation (“braking more than throttling”), the speed tends to decrease, Figure 22.

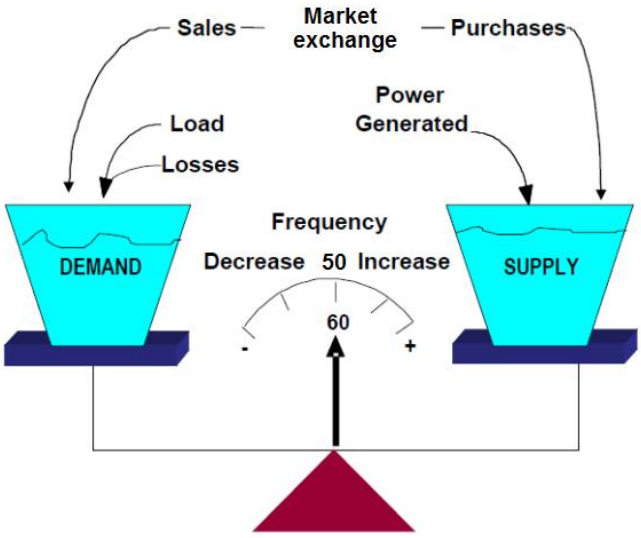


Figure 22 The grid balance. Adapted from[116]

However, since the spinning machines each have a moment of inertia, any imbalances are distributed on all rotating equipment in the grid area. Small fluctuations of a random nature in the generation-demand balance cause minimal changes to the frequency and are evened out.

For larger and more sudden deviations the frequency will change. There is an accepted range in

[116] Balancing and Frequency Control. NERC. January 26, 2011.

frequency for unlimited operation given by the ENTOS-E Grid code[117] with some minor variations between the European synchronous areas where generators are considered to be operative, Table 8.

For a span of 50 +/- 1 Hz, all generators including Type A, Table 9 should be able to operate for an unlimited period. Above 51.5 Hz or below 47.5 Hz, generators are not required to operate, as such deviation can cause serious vibrations in the rotating equipment, degrading load performance and overloading transmission lines, disturbing system protection schemes and ultimately leading to an unstable condition for the power system resulting in load shedding. For larger generators, Type B-D, there are therefore several other requirements to counteract and bridge disturbed operation both up and down in frequency and with other variations without causing a trip, and also maintaining operation without a connection to an external grid (island or house operation).

Table 8 Minimum operational requirements for all generators

Synchronous Area	Frequency Range	Time period for operation
Continental Europe	47.5 Hz – 48.5 Hz	To be defined by each TSO while respecting the provisions of Article 4(3), but not less than 30 minutes
	48.5 Hz – 49.0 Hz	To be defined by each TSO while respecting the provisions of Article 4(3), but not less than the period for 47.5 Hz – 48.5 Hz
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	30 minutes
Nordic	47.5 Hz – 48.5 Hz	30 minutes
	48.5 Hz – 49.0 Hz	To be defined by each TSO while respecting the provisions of Article 4(3), but not less than 30 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	30 minutes
Great Britain	47.0 Hz – 47.5 Hz	20 seconds
	47.5 Hz – 48.5 Hz	90 minutes
	48.5 Hz – 49.0 Hz	To be defined by each TSO while respecting the provisions of Article 4(3), but not less than 90 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	90 minutes
	51.5 Hz – 52.0 Hz	15 minutes
Ireland	47.5 Hz – 48.5 Hz	90 minutes
	48.5 Hz – 49.0 Hz	To be defined by each TSO while respecting the provisions of Article 4(3), but not less than 90 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	90 minutes
Baltic	47.5 Hz – 48.5 Hz	To be defined by each TSO while respecting the provisions of Article 4(3), but not less than 30 minutes
	48.5 Hz – 49.0 Hz	To be defined by each TSO while respecting the provisions of Article 4(3), but not less than the period for 47.5 Hz – 48.5 Hz
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	To be defined by each TSO while respecting the provisions of Article 4(3), but not less than 30 minutes

[117] ENTSO-E Network Code for Requirements for Grid Connection Applicable to all Generators. 8 March 2013

Table 9 Definition of Type B, C, and D generators (Type A < 0.8 MW and connected to < 110kV)

Synchronous Area	maximum capacity threshold from which on a Power Generating Module is of Type B	maximum capacity threshold from which on a Power Generating Module is of Type C	maximum capacity threshold from which on a Power Generating Module is of Type D
Continental Europe	1 MW	50 MW	75 MW
Nordic	1.5 MW	10 MW	30 MW
Great Britain	1 MW	10 MW	30 MW
Ireland	0.1 MW	5 MW	10 MW
Baltic	0.5 MW	10 MW	15 MW

Causes of imbalance

The main reasons for the occurrence of imbalances in power systems are[118];

- Major disturbance, e.g. outage of generation, load or HVDC interconnector – *Power Imbalance*
- Network splitting due to transmission bottlenecks
- Stochastic imbalances in normal operation that can be further sub-divided into:
    - Over Program Time Unit (PTU) (load or production forecast error) - *Energy Imbalances*
    - Within PTU (load or production noise) – *Power Imbalance*
    - Between PTU (ramping of exchange programs) - *Energy Imbalances*
- Market-driven imbalances caused by actions of several market actors within a short time frame

The European Power Systems control philosophy to cope with major contingencies is based on operating the system with Preventive Security Margins (i.e. (N-2) and N-1 for the CE and Nordic synchronous areas, respectively, double circuit fault for the UK, and where N represents one of the largest units in the grid at any time), meaning that the grid area system can cope with a single or double normative event(s) without causing operational problems. This requirement obliges TSOs to plan for and arrange in advance sufficient operational reserves to meet security standards and be prepared to activate further resources in real time, if required, on the basis of advanced models. Since the operational reserve requirements vary over time and must also consider outages and planned maintenance activities on transmission and generating units, the modelling is done over time frames of months and weeks down to minutes, the latter usually being an integral part of the overall SCADA (Supervisory Control And Data Acquisition) system for each Control Area. For the CE synchronous system the security margin is of the order of 3,000 MW, while in the Nordic area it is up to 1,500 MW but is more variable as there are large differences between winter peak and summer low loads. This capacity is by agreement shared between the TSOs in proportion to their capacity or energy usage.

Network splitting causes one or more Control Areas to become partially or entirely separate from a larger Synchronous Area and effectively requires balancing the grid in the Control Area with the resources available within and to and from the Control Area in question.

[118] Impact Assessment on European Electricity Balancing Market. Final Report
Contract EC DG ENER/B2/524/2011. March 2013

Regarding the stochastic imbalances related to forecasting, these are expected to increase significantly, as the balance between controllable generation capacity and non-controllable renewable generation capacity changes towards having an increased share of the latter. This results in the actual production at any time being more subject to forecasting errors than e.g. load, and where the accuracy of forecasts only improves shortly before the actual time period considered.

Random variations in the load or production, relative to more smoothened models and lower time resolution, or in actual versus expected ramp rates of load and generation, will always occur but are of relatively minor importance as they are most often self-balancing due to their random nature.

Market-driven imbalances are typically related to capacity going on or off on a scheduled basis. Since electricity is traded for hourly PTUs/settlement periods, there is a concentration of grid events just before and after the full hour tolls. The sequence of these is difficult to predict and requires special attention and allocation of reserves. For this reason there has been a discussion, and also implementation in certain market areas, of a reduced settlement period of 15 or 30 minutes, as the number of events are distributed over the hour in a better way and the potential amplitude is thus reduced.

Enacting grid balancing

Apart from the common grid stabilization activities within any Synchronous Area where certain generation units are set to control the frequency, and from planned interactions with other Synchronous Areas, the European TSOs within any specific area operate in a “decentralised” way, being responsible for the security of their own system. For instance by implementing preventive N-1 security, they ensure that there are enough reserves, etc. within their Control Area while also providing help proportionally to other Control Areas to compensate for any disequilibrium.

The main interaction within a Synchronous Area is by the joint action of Frequency Containment Reserve (FCR) (also referred to as primary control, primary reserve or FRN) while each TSO is basically responsible for implementation of a Frequency Restoration Reserve (FRR) (also referred to as secondary control and reserves, or FRD respectively) and a Replacement Reserves (RR) (also referred to as tertiary control or reserves respectively).

The functioning of these reserves is indicted in

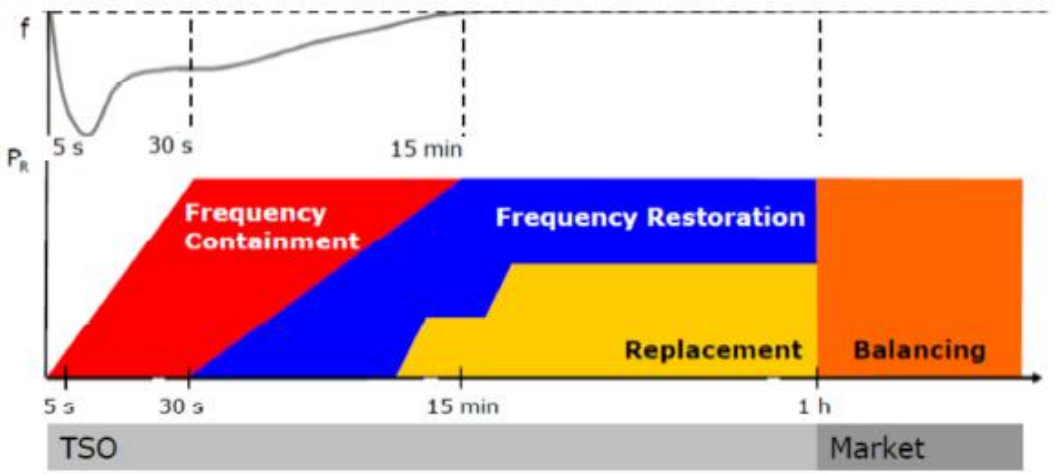


Figure 23. TSOs are responsible for the primary response to a disequilibrium causing a frequency deviation above the threshold by maintaining and activating FCR, which when called on affects all

TSOs in the area automatically. FCR should allow activation within 1-5 s, be ramped to 100 % within 30 s and continue for at least 15 minutes, and are after this period “exhausted” and have to be restored before being activated again. The goal of FCR is to stabilize the frequency deviation but it will not restore the frequency to the desired value. Instead FRR is partially automatically, partially manually, activated by each individual TSO within 30 s and with a possible duration of a minimum of one balance settlement period, i.e. 1 hour, to restore the frequency within the normal operational band. The combination of automatic and manual activation ensures that not more than adequate resources are used initially and that the use of the more fast-reacting resources, which are typically more costly to use and which in some cases can become exhausted, can gradually be replaced with less costly generation units. As FRR is in principle only available for 1 hour, additional capacity is activated from the RR to be used from 15 minutes in the case of the fastest RR response time and then gradually replacing FRR as slower responding units come into production. For durations longer than 1 hr, additional balancing capacity can be procured in the intra-day market. In addition, the TSO can also go to the Balancing Market (BM) to contract additional capacity or activate capacity already under an optional balancing contract. While the FCR, FRR and RR resources were already available to the TSO as part of its obligations at the on-set of the disturbance, contracts on the intra-day market and on BM are subject to normal market mechanisms.

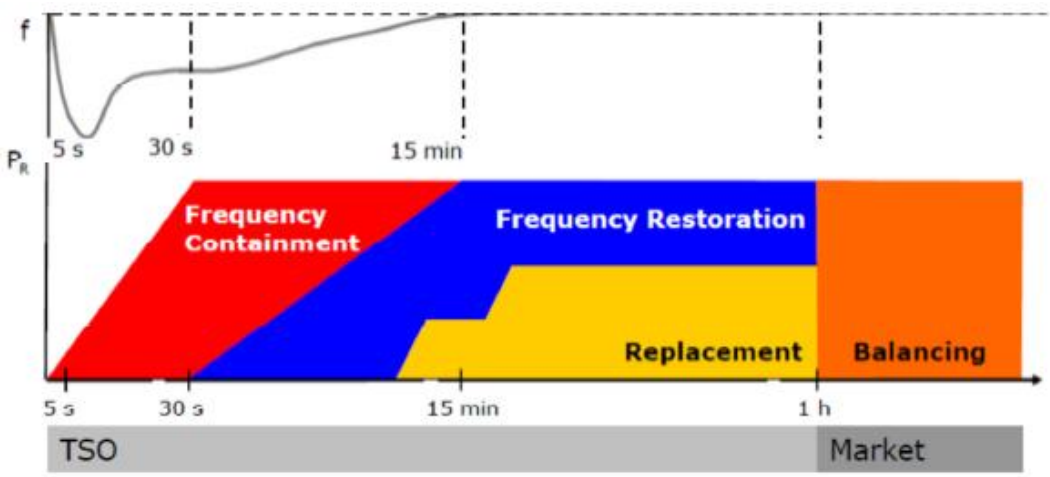


Figure 23 The grid system control hierarchy (adapted from[118])

TECHNICAL DEFINITIONS FOR GRID BALANCING

Activation time: This is the elapsed time between the activation signal (automatic or manual) and the beginning of power delivery, excluding ramping. This parameter allows a market participant to have a minimum notice to deliver the power of its balancing offer.

Automatically-activated reserve: primary and secondary reserves equivalent, which are activated without any manual intervention.

Balancing: process that ensures maintaining the grid frequency stability, within specified and pre-determined stability ranges, through a continuous mechanism aimed at equalling the overall withdrawals and overall electricity injections. Balancing actions are implemented by TSOs (Transmission System Operators).

The power generating plants operated as balancing units (i.e. suppliers of Dispatchable Generation) by turning on/off or adjusting their power output, have to meet specific requirements

for key parameters, depending on the type of reserve they want to cover. There are basically two types of balancing services:

- Response services: quick and automatic activation of balancing power
- Reserve services: related to longer period, power supplied and sustained over this period

Key parameters for power participating in grid balancing service are:

Response time or Lead-in time: Maximum time between the request for, or assignment of the dispatched power, and the time when the power is fully on stream.

Available power: Minimum continuous output power which the generator can deliver.

Duration: Minimum period during which the specified power delivery can be sustained.

Timing: Time at which the availability of the power must be guaranteed.

Cost: This usually depends on the type of service requested

Reserve Types

The balancing service is handled by TSOs, that use different types of balancing reserves and power capacities (MW) to control, period by period, the grid stability. Generation and supply therefore have to remain balanced at all times in order to provide a reliable supply to consumers and prevent damage to infrastructure.

For this reason, TSOs generally manage different contracts, with different payments, depending on the power capacity and service availability. Indeed, reserve capacity can be provided by several different sources with different response times, in a wide range from a second to several hours: these reserves are also called “dispatchable assets”.

Nevertheless, it is also possible that the reserve is unable to meet the demand: therefore, balancing must be achieved by reducing the demand from industries (i.e. metallurgical industry) who have agreed to enable TSOs to reduce their power consumption. This type of balance can act very quickly.

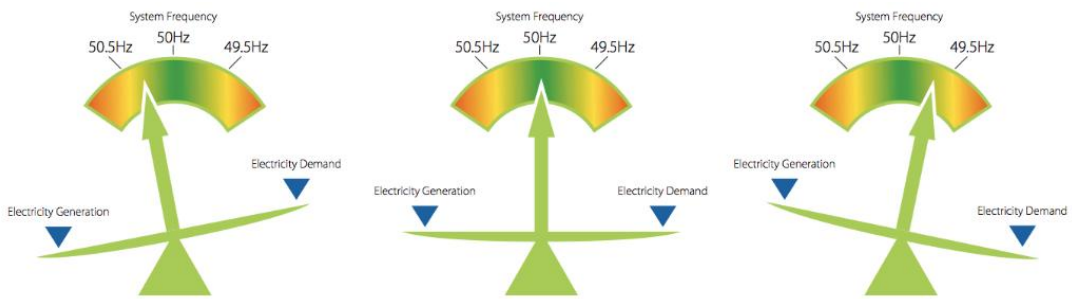


Figure 3 Supply and Demand Balancing (Ricardo, 2011)

Grid imbalances due to the variation of demand are balanced by TSOs through the use of small flexible plants such as internal combustion engines or gas turbines used for stationary energy production, and large capacity plants operating at partial load (spinning reserve), that can respond

more quickly to the demand changes in the grid. Bioliquids could play a significant role in this context in parallel with natural gas or diesel. Batteries can provide the fastest response, with less than one second lead-in time and ramping rates, and for this reason they are often coupled with engines and gas turbines. These flexible stand-by power stations with a highly variable rate capability are also called "fast assets" or "dispatchable assets". However, running a power generation system at part-load in order to be ready for grid balancing generally means low efficiencies and higher production cost.

In the following, a table describing reserve types for the UK is reported as an example.

Table 2 Reserve Type description[119]

Reserve Type	About	Technical Requirement	Technology Need
Fast Reserve ***- Frequency Response*** ***- Load Following Supply*** ***- Peaking Supply***	Fast Reserve is used, in addition to other energy balancing services, to control frequency changes that might arise from sudden, and sometimes unpredictable, changes in generation or demand.	Active power delivery must start within 2 minutes of the despatch instruction at a delivery rate in excess of 25MW/minute, and the reserve energy should be sustainable for a minimum of 15 minutes. Must be able to deliver minimum of 50MW.	Prime movers such as gas turbine and internal combustion engine are often used to drive smaller capacity generators to supply the varying loads as well as standby power. Need good Ramp Rate
STOR **Short Term Operating Reserve**	Short Term Operating Reserve is needed because at certain times of the day National Grid needs reserve power in the form of either generation or demand reduction to be able to deal with actual demand being greater than forecast demand and/or plant unavailability. Where it is economic to do so, National Grid will procure part of this requirement ahead of time through STOR.	Spare capacity that is already on-line but unloaded or not running which can respond within 10 minutes. This also includes "hot standby" generators which are ready to run, but not fuelled. They may be expected to supply the full contracted power for over 4 hours.	Need both good ramp rate and short start-up
Start Up	National Grid will offer contractual arrangements to Generators so that upon request by National Grid the generator will begin the process of readying the plant to start generating.	BM Start Up: - Have the ability to prepare the generator towards a state of readiness in order to synchronise the unit upon instruction within Balancing Mechanism timescales (89 minutes from instruction). Typically this involves warming the unit up in order to allow a quick synchronisation time. - Be capable of terminating	Need Short Start Up

[119] Nationalgrid, 2016. What are Reserve Services? United Kingdom. Available at: http://www2.nationalgrid.com/UK/Services/Balancing-services/Reserve-services/

	the BM Start Up process at any time prior to reaching Hot Standby.

The following reserves belong to the category of Spinning Reserves, defined as "the extra generating capacity which is available from base load generators to compensate for generation or transmission outages by turning on, or increasing the power output of, generators that are already connected to the power system". The spinning reserve capacity ranges, typically, from 15% to 20% of the normal base load. They are the first to start, and involve high capital and operation costs since they relate to plants providing the base load.

Frequency response or Immediate reserves – TSOs must keep the system frequency of the grid within pre-defined limits. Frequency response can be utilised to address unexpected drops in generating capacity. For this reason, Frequency Response is provided as an automatic reaction to a loss in supply, covering initial transient loads maintaining system frequency. This service can be available in a very fast time, such as 5 or 10 seconds, being supplied by generators running at less than full capacity but that are already delivering power. Power requirement could be up to 50 MW for over 15 minutes.

Operating Reserve (Dispatch Reserve) - Generation capacity that is off-line or kept on-line but unloaded, such as "hot stand- by systems" (ready to run but not fuelled), and that can be available within 10 minutes. This reserve service is used after all spinning reserves are on-line. They may be expected to supply the full contracted power over a period of some hours.

Standby Reserve - This service can be activated when short term load increase is planned, so to provide additional short-term operating power. Contract service for stand-by reserve requires to be on-line within twenty minutes, and to keep running for up to four hours. Technologies which are usually adopted for stand-by reserve are small scale (> 250 kWe, for instance) units for stationary energy production: these can typically be operated less then about twelve times in one year, and therefore their utilisation or load factor is very low. As a consequence, these under-utilized systems are non-economic.

In addition to Spinning Reserves, Fast Reserves are also employed to balance the grid.

When power output is adjusted almost continuously (in the order of a few minutes) to follow the variable demand while keeping frequency and voltage in the correct range, this mode of operation is called "Load Following". Clearly, the plant will not be operated at design capacity for most of the time, with lower efficiencies, higher costs, etc. Systems that are operated in Load Following mode are hydropower plants, gas turbines fed with natural gas, or diesel and gas engines at very small scale: while the first ones can typically take load in 2-5 minutes, engines can be as fast as 10 seconds.

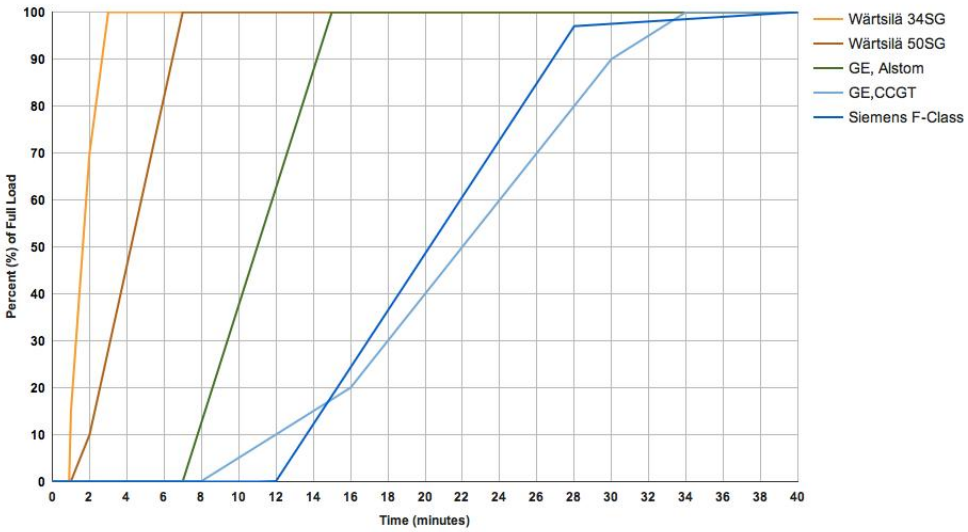
Where a very high (peak) demand occurs, generators like gas turbines can be run to provide emergency power (Peaking Supplies). This operation is very expensive, relying on flexible but costly gas turbine systems. Diesel engines can also play this role, but only in the case of smart grids and small networks. Obviously, these plants are characterised by an extremely low load factor (even 2 %), and represent very underutilised systems.

Technologies able to satisfy the need

GTs vs ICEs Start-up (Start Times Graph)

As stated, power plants that can be dispatched within minutes are important assets for balancing electric system loads and maintaining grid stability. The generating technology affects the time required for a power plant to start-up and reach full load. While combined cycle gas turbines can take over 30 minutes to start, combustion engine power plants can reach full load in less than 10 minutes, providing flexible and quick-start capability.

Figure 4 Example of Combustion Engine vs Gas Turbine Startup Time.



(http://www.wartsila.com)

Figure 5 Starting Load Delivery. Gas Turbines vs ICE. (http://www.wartsila.com)

GTs vs ICEs Flexibility (Ramp rate)

A means to measure plant flexibility is to analyse the ramp rate, which is the rate at which the plant can increase or reduce power generation and thus meet the load. Typical ramp rates for different kinds of units are listed below, and given as a percentage of capacity (www.wartsila.com):

- Diesel engines 40 %/min
- Industrial GT 20 %/min
- GT Combined Cycle 5 -10 %/min
- Steam turbine plants 1- 5 %/min
- Nuclear plants 1- 5 %/min

Ramp rates for industrial gas turbines can be in the range of 10 MW/min to 100 MW/min, while small-scale gas turbines stay between 100 and 200 kW/s. Engines are typically faster than gas turbines, having ramp rates above 250 MW/minute. However, multi-shaft gas turbines can perform better than single-shaft systems.

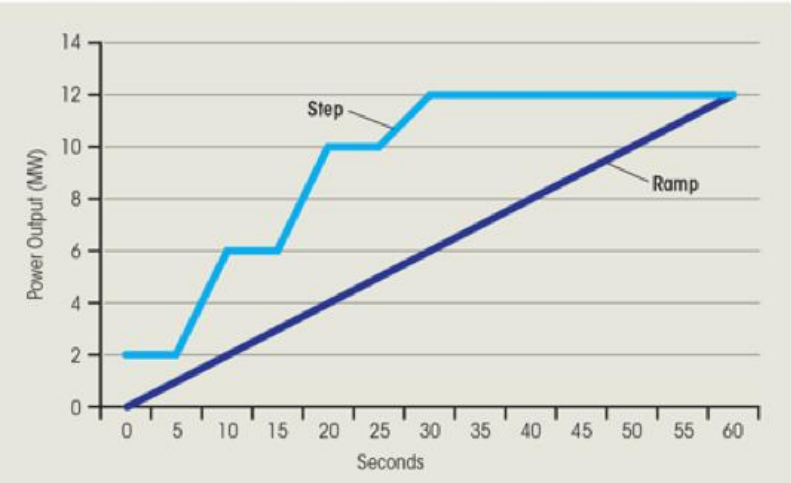


Figure 6 Expected Ramp Rate and Step Load Acceptance for a twin-shaft Turbine (http://www.power-eng.com)

Power Plant Modularity for enhancing the ramp rate

A modular system will offer higher plant flexibility and capability to adapt to variable load. Thus, having multiple units will help to keep high power plant availability, achieve operational flexibility

and keep good performances at various loads. As an example, depending on plant configuration, combining multiple gas turbines in Combined Cycle Gas Turbines could achieve 100 MW/min with systems having a ramp rate equal to 50 MW/min each (http://www.power-eng.com).

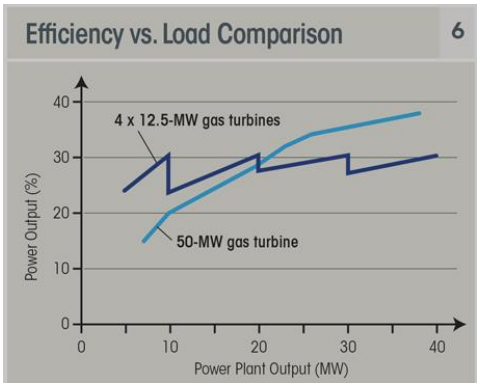


Figure 7 Efficiency versus load comparison (http://www.power-eng.com)

As shown in the figure above, in terms of net efficiency, a single 50 MW GT would be less competitive than four open cycle 12.5 MW GTs, and thus less suited to follow the load with acceptable economic performance.

Example of Ramp Rate ensuring grid flexibility

Balancing the grid requires interventions at different ramp rates, and this will involve the operation of different systems capable of meeting the specific requirements. As an example, in the following figures it is shown how a capability to ramp 400 MW in one hour (6.7 MW/min), 80 MW in 10 minutes (8 MW/min), and 10 MW in one minute (10 MW/min) is necessary in order to meet all MW variations seen in the system.

Figure 8 Load variability on hourly, 1-minute and 10-minutes basis[120]

[120] McCalley J (2016). Wind Power Variability in the grid: Regulation. In Wind Energy Honor Course, Iowa State University. Available at: home.eng.iastate.edu/~jdm/wind/Regulation559.ppt