KMB Balance management in multinational power markets

WP2: Documentation and analysis of present costs

16. March 2008

Content

1. Background

The growing integration of European power markets provides opportunities with regards to the exchange of balancing services between control areas in different countries. Having a system-wide approach instead of a control area approach, may reduce reserve costs. Cost savings are partly obtained because plants can be operated at a higher efficiency and partly because cheaper plants can be used to provide reserves.

Balancing reserves have so far to a limited degree been eligible for trading between control areas. However, increased power market integration and a rapid expansion of new renewable energy sources with less predictable output, may increase such trade.

Reserve trading is particularly interesting between the Nordel area and UCTE members such as Germany and the Netherlands. Firstly, because the significant hydro power capacity found in the Nordel area has ideal characteristics for providing balancing reserves compared with thermal plants in the UCTE area. Secondly, because of the increasing integration between the Nordel system and the UCTE, amongst others through the NorNed cable and the planned cables to Germany.

On this basis Sintef has initiated the; "Balance Management in Multinational Markets" project. The main objective of the project is: *"To design the scientific foundation for a framework for efficient, market-based balancing of power systems that can be implemented in multinational power markets"*

A number of ancillary services could be traded between control areas and countries. However, Sintef's Balance Management project mainly focuses on:

- Frequency containment reserves (primary reserves) – reaction time 0-30 sec
- Frequency restoration reserves (secondary reserves) – reaction time 30s – 15 min

2. Scope of Work Package 2

The Sintef Balance Management project consists of five work packages that will provide the basis for and the input to the final report. This report covers Work Package 2 (WP2), where the goal has been to:

- Identify present balancing recourses from thermal generators >100 MW and from large consumers >25 MW in Germany, the Netherlands, Belgium, Sweden, Finland and Denmark
- Provide data that can be used for modelling balancing costs in and between these countries

In order to obtain the necessary data for WP2, ADAPT has been in direct contact with thermal power plant owners/operators, power plant producers and large consumers. ADAPT has also gone through existing documentation on balancing costs, as well as operational aspects regarding industry and power plants. The most relevant findings from these documents have been included in this report. The main product of WP2 is the attached list of thermal power plants and chapter 6 of this report which supplements the list, covers balancing reserve costs and operational aspects for large industrial consumers.

The following technical report has been divided into four parts:

1. Balancing reserves – An overview
2. Power plant list – Data category explanation
3. Power plant list – Background, assumptions and operational aspects
4. In depth study of relevant operational aspects, costs and volumes regarding demand side delivery of balancing reserves

3. Balancing reserves

General overview

In order to ensure stable and reliable operations of interconnected power systems, it is necessary to maintain a sufficient reserve capacity against contingencies. Frequency containment reserves (primary reserves) and frequency restoration reserves (secondary reserves) are thus essential for a well functioning power system.

Primary control is the instantaneous reaction of the speed governor to frequency deviations in the system, in order to restore balance between production and consumption fully or to a quasi-steady-state. The primary control reserves can be divided into normal operating reserves (incl. frequency bias) (FAOR) and contingency reserves (FACR) for larger unexpected deviations.

Secondary control or load-frequency control (LFC), enables a control region to regain the desired output after a disturbance, returning the system frequency to normal and the agreed exchange between interconnected regions to their reference value. In the UCTE secondary control are fully automatic control actions, activated by the Automatic Generation Control (AGC). In the Nordel area secondary control are manually activated control actions (see WP1 for further information on balancing reserve definitions).

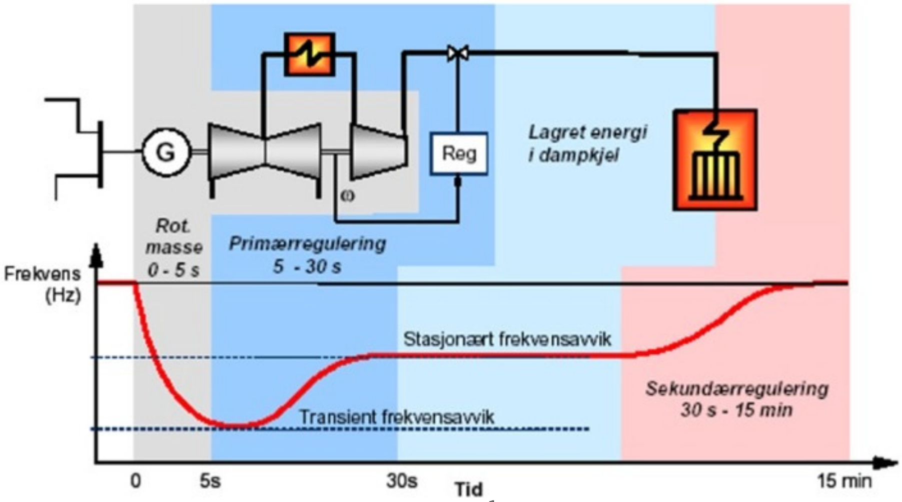


Figure 1[1]

Figure 1 above, shows how primary and secondary reserve capacity from a thermal power plant is used in the case of a sudden load increase (fall in frequency) to restore system frequency. Initially (0-5s) the frequency falls to the transient frequency deviation level (maximum instantaneous frequency deviation level), only slowed down by the resistance of the rotating mass of the generators. Within seconds (0-30s) the speed governor responds to the frequency fall by increasing output. The increased output lifts the frequency to a so called quasi-steady-state frequency (a steady frequency below the system frequency). The primary reserve reaction time is in fact faster in thermal plants than in hydropower plants. However, since thermal plants use stored heat energy to deliver primary reserves, the response can only be maintained for a relatively short period of time. Hydropower plants on the other hand, can maintain increased output for hours, if necessary.

Within 30s – 15 min the Automatic Generator Control (AGC) in the UCTE or the TSOs in the Nordel area (manually), sends a signal to the unit to increase output and thus deliver additional reserves (secondary reserves). The additional output lifts the frequency from the quasi-steady-state to normal system frequency and at the same time replacing primary reserves.

Primary reserves

Since the nature of primary reserves is complex, especially with regards to cross country exchange, the main emphasis in the Sintef project has been put on the exchange of secondary reserves. Still we have included a short overview below on the principals of primary reserve delivery.

Primary reserves are, as mentioned earlier, quick/instantaneous responses to changes in system frequency. Primary reserves can be offered by both consumers and producers. For consumers an

[1] Bakken Bjørn B: "Frekvensregulering I varmekraftverk – Tekniske løsninger og kostnader", Sintef prosjekt AN 05.12.54, July 2005

instantaneous response can be provided by load shedding. Increased instantaneous production is also fast, but will in most cases be a slower process than load shedding. Generally speaking load shedding, as opposed to load increase, is the most relevant, if not the only reserve industrial consumers will/can provide.

In order for large industrial consumers to deliver primary reserves, frequency responsive equipment must be installed. When such equipment exists, the response is faster than all other reserves. The technical aspect of demand side primary reserve delivery is not very complex, and quite intuitive. However, some operational aspects may be quite complex and will be discussed in more detail in chapter 6 of this report.

In the following primary reserve responses from thermal power plants are discussed. Most of the information is taken from Sintef Ph.D. Bjørn Bakken's earlier work[2] as well as some updated data, which ADAPT has received from power producers.

Primary reserves from thermal power plants are today mainly provided in two ways (although other methods also exist):

- High Pressure (HP) control valve dethrottling. This method is mainly used in older plants
- Condensate flow stoppage (also in combination with HP control valve dethrottling). This method is used in modern coal and oil fired power plants

HP control valve dethrottling does not require additional investments in the power plant, however, this method forces the producer to deviate from sliding pressure operation, which increases energy use and thus reduces efficiency. This is illustrated in figure 2 below, which shows the increased steam pressure from point B (sliding pressure) to point A (HP control valve dethrottling), without an increase in output.

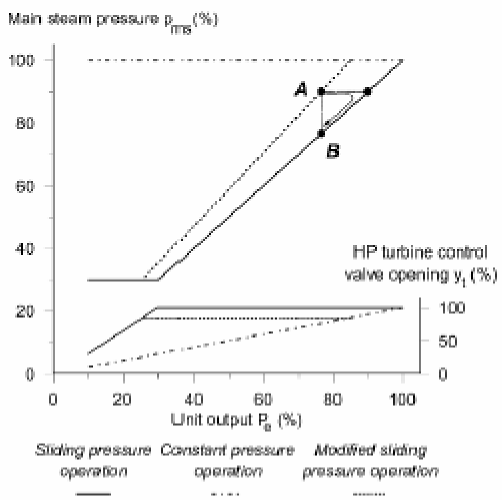


Figure 2

[2] Bakken Bjørn B: "Frekvensregulering I varmekraftverk – Tekniske løsninger og kostnader", Sintefprosjekt AN 05.12.54, July 2005

Condensate flow stoppage (CondStop) on the other hand requires some additional investments (approx. 5 MNOK), however the method has less effect on efficiency and thus primary reserves can be delivered at a lower cost. Operators that ADAPT have spoken to claim that CondStop related investments would be made regardless of primary reserve delivery. The producers ADAPT has been in contact with, have not been able to provide efficiency reduction data related to the CondStop method.

According to power producers ADAPT have contacted, the most common method for delivering primary control for older plants is High Pressure control valve dethrottling. Newer plants on the other hand, use a combination of CondStop and HP valve dethrottling. The method of dethrottling HP control valves maintains a reserve by keeping the main steam control valves in front of the HP turbine slightly throttled during normal operation. Additional output can then be achieved quickly by opening the valves and releasing stored steam from the boiler.

Generally speaking the increased output that can be produced within seconds is about 40-50% of the throttled reserve since only the HP section of the turbine reacts spontaneously. Thus, in order to supply an increased power output of 5%, a throttle degree of about 10% would be necessary. Units operating at constant main steam pressure have a "natural" throttle reserve when operating below rated output. However, maximum allowable pressure reduction limits the use of this reserve.

Due to the insufficient reserve capability as a single action, the method of CondStop is often combined with a slight throttling of the HP control valve to fulfil the reserve recommendations. This method is called combined condensate stoppage. The necessary amount of throttling is reduced using this method, resulting in a considerable reduction of operation costs. At loads above 78% of rated output, most units can provide 5% additional output within 30 seconds without HP valve dethrottling. However, most units using the CondStop method operate with a minimum throttle degree of 2% also above 78% load to handle small frequency deviations.

The cost of de-throttling can be approximated by making the following assumptions for a conventional coal fired steam plant (ADAPT estimate):

- electric efficiency of 42%
- HP-turbine share of 50%
- a linear correlation between de-throttling and output

A 5% of rated output primary reserve capability, would then require 10% HP valve de-throttling and thus reduce efficiency to 37,8%.

In one of his studies[3], Bjørn Bakken estimates the cost of HP valve dethrottling to be between 4-8% of total annual operating costs. In a specific example Bakken estimated the costs related to HP valve dethrottling to be between 7000 – 25 000 €/MW/year, given 70 $/ton coal, 29 GJ/tonn for a coal fired plant. For a gas fired power plant the figures where expected to be between 14 000 – 55 000 €/MW/year given 2 NOK/Sm3 and 40,3 MJ/Sm3. The CondStop method is expected to have substantially lower costs.

[3] Bakken Bjørn B: "Frekvensregulering I varmekraftverk – Tekniske løsninger og kostnader", Sintefprosjekt AN 05.12.54, July 2005

Secondary reserves

In order to provide secondary reserves, a consumer or producer must reach full regulating effect (up or down) within a 30 sek to 15 min time frame. Most Nordic hydro power plants and many industrial consumers can meet this time response requirement. However, as opposed to the automatically activated reserves in the UCTE system, Nordic hydro plants and most industrial consumers require or are based on manual activation.

Hydro plants can relatively easy and at a low cost provide secondary reserves by regulate their production up and down. Thermal power plants, on the other hand, may incur substantial costs when delivering such reserves. When deviating from 100% of rated output, most thermal plants will produce at reduce efficiency. In addition, providing secondary reserves requires investment costs in AGC equipment, increased maintenance and ware/tare costs caused by output changes. Still the main cost of providing secondary reserves, are generally thought to be "system costs". System costs arise when a "cost optimal" production plan has to be rearranged to accommodate the provision of secondary reserves.

For industrial consumers the most relevant balancing action is to reduce load (load shedding). Cutting loads for periods of > 1-3 hour, may cause serious problems and also increase costs substantially. This will be described in more depth in chapter 6 of this report.

4. Power plant list – Data category explanation

Background

The power plant list included in WP provides a wide range of unit specific data. In this chapter a short explanation is given for each data category.

Data category specifics

Country
Lists the country where the plant is located. The countries covered in the list are; Sweden, Finland, Denmark, Germany, The Netherlands and Belgium.

Plant name/location
Lists the name of the power plant and/or its location.

Owner/operator
Lists the power plant owner and/or operator. Where there are multiple owners, only the majority owner or the largest owner is listed.

NOTE: Ownership information of certain units may be outdated due to the rapid and constant change of ownership in the European and Nordic power market. During the past 5-10 years there have been considerable consolidations in the power market. The ownership of most of the power plants in the list has changed during the past few years or is about to change. This makes it difficult to maintain an up to date list at all times. Still, although power plant ownership is hardly relevant for the Sintef project and modelling, ADAPT has tried to make the list as complete and correct as possible.

Net capacity

Lists the net electric capacity of the power plant in MW.

NOTE: Large power plants have, as far as possible, been divided into separate blocks. However, in some cases the net capacity listed for a certain unit, is the sum of several power blocks (e.i. 4 x 400MW = 1600MW plant). Each block can in most cases be operated independently of the other blocks.

Heat delivery

Lists whether the power plant is a combined heat and power plant (CHP) or not. Heat delivery is divided into two categories; district heating denoted (DH) or industrial heat (back pressure) denoted (BP).

NOTE: For further information and background on heat delivery see chapter 5.

Power plant type

Categorizes each unit into one of the following six power plant types:

- Nuclear - Nuclear power
- CC – Gas Turbine with steam cycle => combined cycle
- GT – Gas turbine => simple cycle
- ST – Steam turbine => boiler with steam cycle
- Combi – Gas turbine and a fired boiler with steam cycle
- Hydro – Hydro power plants

<u>Nuclear</u>

Nuclear plants use uranium to produce steam, which is used in a conventional steam turbine cycle. The nuclear power plants in the list are divided into Pressurized Water Reactor (PWR) and Boiling Water Reactor (BWR)

<u>Combined cycle</u>

Combined cycle plants or CCGT plants, combine a gas turbine cycle and a steam turbine cycle (thus combined cycle). The heated exhaust from the gas turbine is used to produce steam in a Heat Recovery Steam Generator (HRSG), which is used to run a steam turbine cycle. Some combined cycle plants also deliver heat for district heating and industrial purposes and fall under the category combined heat and power (CHP-plant).

<u>Gas turbine</u>

Gas turbines are simple cycle gas turbines with no steam cycle. Gas turbines can use both natural gas and gas oil.

Steam turbine
Steam turbine (ST) plants use coal, oil and gas in a boiler to produce steam. The steam is used in a conventional steam turbine cycle. Steam turbine plants that only produce electricity are often referred to as "conventional" thermal plants. Steam turbine plants that deliver both electricity and heat are called combined heat and power plants (CHP-plants).

Combi plants
The combi plants referred to in this report are combined GT and ST plants. Combi plants can be divided into two categories depending on their technical build up:

- ST based plants (Gas/Coal combi)
- CC based plants (Gas/gas combi)

ST based plants are basically coal fired plants with a GT addition. The GT is usually used for peaking purposes. The main part of the plant is thus the ST part.

CC based plants are CC plants with additional combustion in the boiler. Such plants are generally based on gas.

In both cases the gas turbine cycle and the steam cycle, usually can be operated independently This gives added flexibility both with regards to electricity and heat delivery.

Primary and secondary fuel
Lists the primary and the secondary fuel in separate columns.

NOTE: When determining marginal costs the primary fuel is used.

Fuel category

- For coal: 1 = hard coal (or equal) ; 0 = lignite (or equal including bio)
- For oil: 1 = gas oil ; 0 = heavy fuel oil

The fuel category (1/0) influences price and/or efficiency assumptions for a specific unit.

Efficiency
Lists the net electric efficiency at 100%, 75%, 50%, 25% of rated load.

NOTE: For additional background on efficiency assumptions and calculations see chapter 5.

Info based
An "x" indicates that the listed "100% load efficiency" for a specific unit, is the actual efficiency based on publically available information.

Efficiency corrections
Lists the corrections made to the estimated "100% load efficiency", in order to get actual efficiency found through publically available information.

Marginal fuel cost

Lists the marginal fuel cost of each unit at different loads (100%, 75%, 50%, 25%). The marginal fuel cost is determined using the cost of primary fuel and the efficiency for each plant.

NOTE: For combi plants the dominant fuel is used. Thus in a gas/coal plants the coal price is used even though both gas and coal can be used in combination at the same time.

Marginal CO2 cost

Lists the marginal CO2 cost of each unit at different loads (100%, 75%, 50%, 25%). The marginal CO2 cost is determined using primary fuel emissions, cost of CO2 and the efficiency for each plant.

NOTE: For combi plants the dominant fuel is used. Thus in a gas/coal plants the CO2-cost of coal is used even though both gas and coal can be used in combination at the same time.

Total marginal cost

Lists the total marginal cost of each unit at different loads (100%, 75%, 50%, 25%). The total marginal cost is the sum of marginal fuel cost and marginal CO2 cost.

Start/stop costs

Lists the units estimated start/stop cost.

NOTE: For more information on start/stop cost assumptions and calculations see chapter 5.

Start year

Lists the year a unit (single block or the plant as a whole) started production. The start year is used as a basis when estimating plant efficiency. If revisions have been made, the revision year is used as start year.

Plant history

Lists the historic build up of the plant, including revisions and upgrades and indicates planned shutdowns where this information is available.

Special comments

Other relevant information about a specific plant has been included in this column.

5. Power plant list – Background, assumptions and operational aspects

Background

This chapter provides additional, in depth information regarding assumptions and calculations made in the power plant list especially concerning:

- *Efficiency*
- *Start/stop costs*
- *Fuel and CO2 prices*

This chapter also provides some supplementary information on important operational aspects that are not included in the list, but that may be useful when modelling.

Efficiency – general aspects

The Sintef project focuses mainly on electricity. Thus efficiency data provided in the power plant list and in this report only covers electric efficiency. Note that the total thermal efficiency including heat delivery, may be substantially higher than the net electric efficiency.

Efficiency, as used in this report, referrers to the net electric efficiency at the lower heating value (LHV). This is the most common reference in Europe. In the US higher heating value (HHV) is often used. HHV generally lays 10 % above the LHV.

The efficiencies listed reflect the technically achievable efficiency and not the actual annual average efficiency. The actual efficiency may vary between years, due to variations in ambient temperature, operations and changing heat delivery over the year.

One of the major difficulties when estimating the efficiency of power plants based on age classes, is retrofitting. Retrofitting can improve a power plant's efficiency over its lifetime, so that the efficiency at the beginning of its operation is lower than at the end of its lifetime. Retrofitting has been taken into account in the efficiency calculations where such information has been available; still there is a risk that the efficiency is underestimated.

Efficiency – data sources

ADAPT has been in contact with a number of sources in order to obtain efficiency data for the power plant list. Still, the efficiencies provided in the power plant list are calculated efficiencies based on specific formulas and criteria (these will be discussed below). ADAPT has chosen to calculate and thus estimate the efficiencies of each unit for two reasons:

- It has not been possible to obtain actual unit specific data for all units in the list. Thus ADAPT needed to come up with a model for estimating the efficiency for these units.

- The power producers that have given ADAPT access to actual operational data has not authorized the use of unit specific data in this public study in a way which specifies that these are actual data. However, ADAPT has used the actual data to develop and cross-check formulas that can estimate power plant efficiency based on power plant type, fuel and age.

Note that the calculated efficiencies have been adjusted to reflect actual efficiency at rated output, where information on real efficiency has been made publically available.

Efficiency – determining factors

Although the formulas used to calculate unit specific efficiency in the power plant list generally provide good approximations, actual efficiency may in some cases be over/under-estimated. This is due to the fact that actual efficiency is influenced by a number of complex factors such as.

- Ambient temperature
- Pressure and heat
- Fuel (type and quality)
- Type of plant
- Age of plant
- Type of technology
- Heat integration
- Operational mode

Efficiency aspects concerning different power plant types

Nuclear

Up to 70% of the energy produced in a nuclear power plant is extracted as useful heat. Still, close to half the heat energy is lost in the process. Thus nuclear power plants in general only achieve 32-34 % efficiency.

Compared to the efficiency improvements made in fossil fuel power plants, the efficiency improvements of nuclear power plants have been relatively small. A widespread presumption within the appropriate literature is that the average efficiency of the existing stock of nuclear power plants is around 33%. ADAPT has used this presumption in the power plant list.

Even though generalizing the efficiency of nuclear power plants to 33% may lead to an +/- 3% over/under estimation of the efficiency for certain units, this will have little or no effect on production choices and/or modelling results. This is due to the fact that fissil fuel is substantially cheaper than any fossil fuel type. This is also why nuclear power plants are assumed to have 0 (or irrelevant) start/stop costs since ADAPT has found no cases where fuel costs have led to a shutdown of a nuclear power plant.

Small variations in production due to primary or secondary reserves within the 75-100% of rated output range will in most cases have a small effect on the efficiency of a nuclear power plant. Still, nuclear power plants are associated with very high fixed costs making the capacity price high. Thus, although delivering primary and secondary reserves may be technically possible, such reserves are not primarily provided by nuclear power plants.

Note that many Continental nuclear power plants are sensitive to heat, since hot weather increases cooling water temperature, which may force nuclear power plants to reduce loads. This has occurred several times during the summer the past 5 years. Reduced load will also reduce efficiency, however, may open for the delivery of balancing reserves.

Steam turbines

Simplified steam power plants consist of a boiler, a turbine, a condenser and a feed-water pump. The fossil fuel, burned in the boiler generates steam from water. Then the steam expands in the turbine, which powers the generator. After that, the flashed steam cools in the condenser down to its liquid state again. The pump feeds the water back into the boiler.

The essential parameters, determining the efficiency of steam power plants are;

- steam pressure
- temperature

In order to increase temperature and pressure one is dependent on materials and technologies which fulfil the requirements that come along with the improved parameters. During the last few decades continuous efficiency improvements of conventional steam power plants have taken place. The development of materials, which allow higher critical steam conditions, have been a decisive contribution. The introduction of resistant materials has made it possible to increase steam parameters compared with the traditional 165-250 bar/540°C/565°C (steam pressure/steam temperature/reheat steam temp.) used during the 60's. The following chart shows how some steam cycle parameters can efficiency:

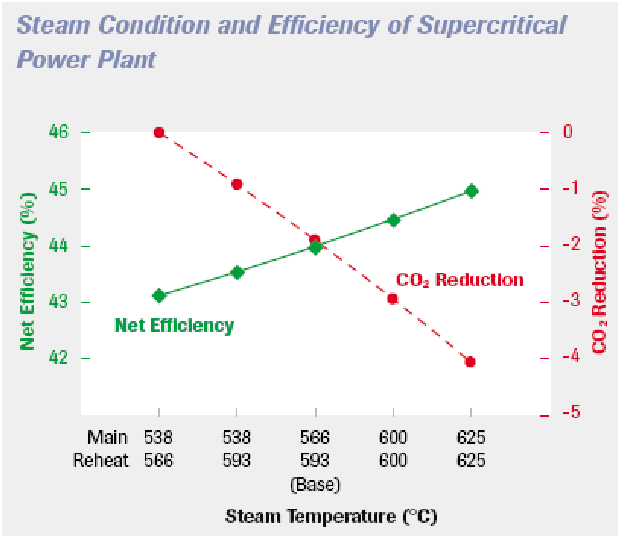
Steam parameters and efficiency on coal power plants

	Ref. cycle	Cycle 2	Cycle 3
Boiler outlet conditions	265 bar 553°C/571°C	270 bar 583°C/601°C	290 bar 603°C/621°C
Final feed water temp.	290 °C	290 °C	300 °C
Efficiency increase	Ref.	+ 1,9 %	+ 3,5 %
Operating conditions: 7000 hours / year			

Source: www.power.alstom.com

The graph below shows the relationship between steam temperature and efficiency:

Steam temperature conditions and efficiency of coal power plant



Lignite and hard coal steam power plants
Steam power plants which produce electricity from hard coal and lignite make up a substantial amount of the units in the power plant list. While Lignite fired power plants are used and designed for base load operation only, hard coal fired power plants are suitable for both, base load and shoulder load operation.

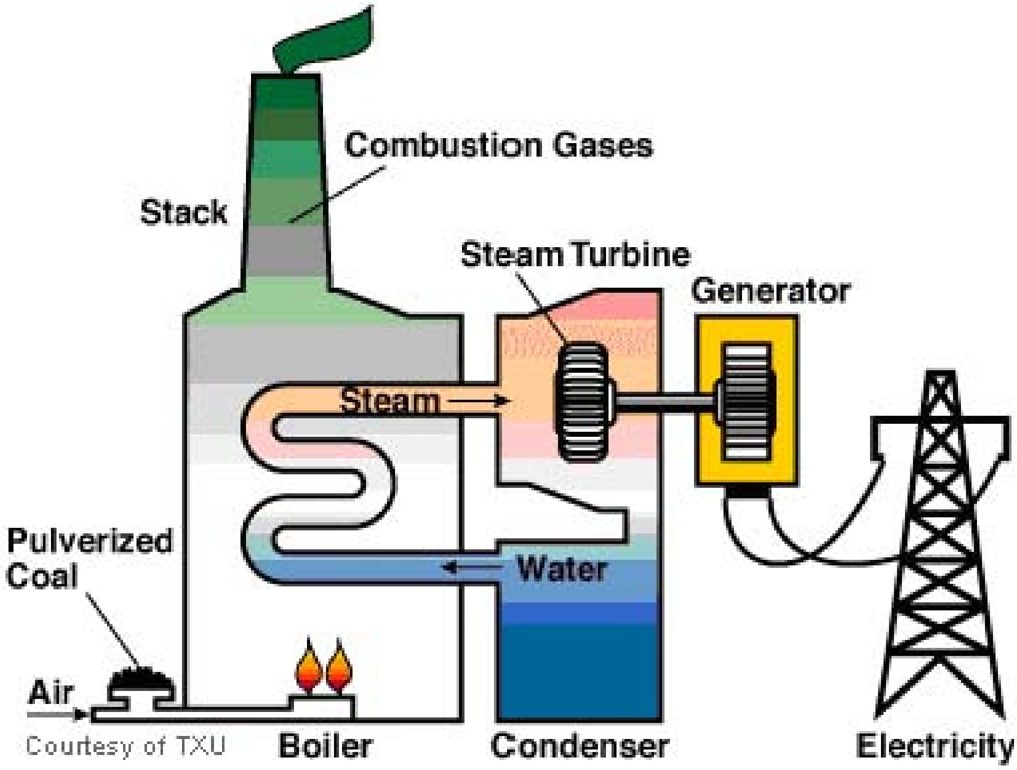
When studying the efficiency of lignite and hard coal fired power plants, it is conspicuous, that lignite power plants seem to have a lower efficiency than hard coal fired power plants build in the same year. The difference in efficiency is due to the higher humidity content of lignite. Thus lignite fired power plants normally have an efficiency that is a few percentage points lower than hard coal fired power plants with similar process technology.

Gas and oil fired steam power plants
The technology of "conventional" gas and oil fired power plants is essentially the same as the technology for lignite and hard coal fired steam power plants. However, combustion with gas and oil results in lower flue gas losses compared to hard coal plants. Thus gas and oil fired steam plants normally achieve an efficiency that lies 1% higher than for an identical hard coal plant.

Coal based stem power plants technologies
The predominant coal-fired power generation technology in the world today is Pulverised Coal Combustion (PCC). PCC accounts for around 90% of power plants in operation today. Most of the remaining plants are Fluidised Bed Combustion plants (FBC) and only a few IGCC (Integrated Coal Gasification Combined Cycle). In the following a short overview of these technologies will be given.

Pulverised Coal (PCC) Combustion

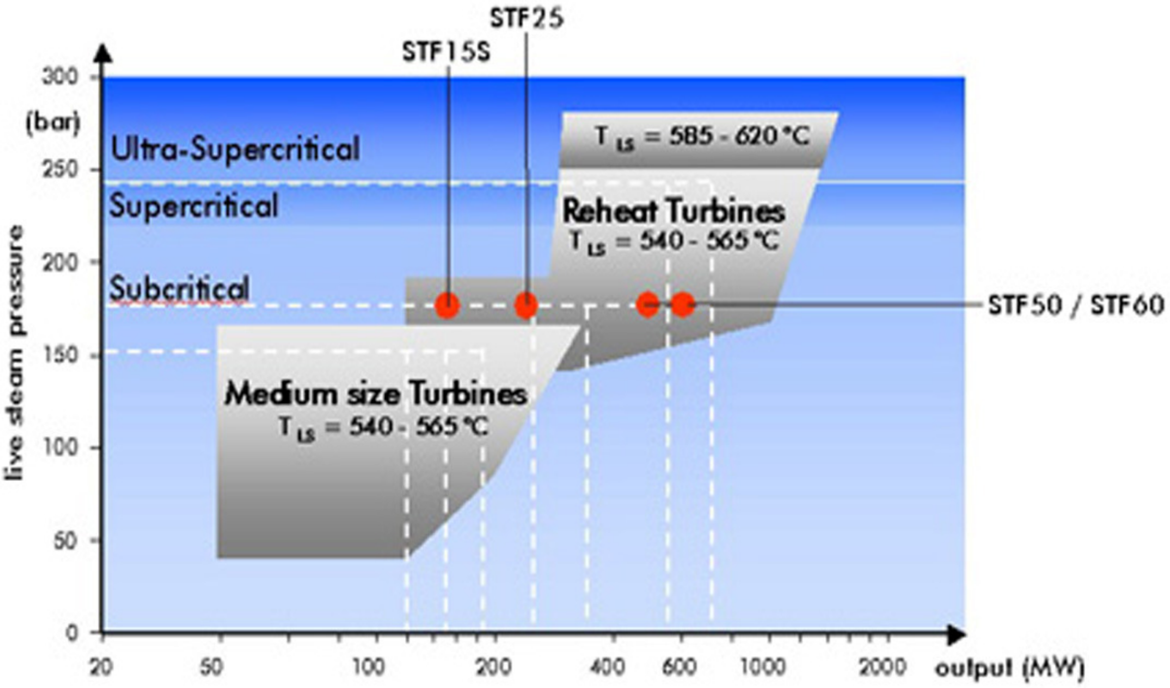
PCC is the main method for generating electricity from coal. The process of a PCC unit is described below.



Source: World Coal Institute (wci.rmid.co.uk)

In the PCC plant the coal is milled to a fine powder in a pulveriser, which increases the surface area of the coal and hence the rate of combustion. The powdered coal is blown into the combustion chamber of a boiler where it is burnt at around 1400°C. The hot gases and radiant heat energy produced, convert water in tubes lining of the boiler into steam. The hot and high pressure steam is passed into a steam turbine containing thousands of propeller-like blades. The expanding steam hits these blades causing the turbine shaft to rotate at high speed. Mounted at the end of the turbine shaft is the generator. After passing through the turbine chamber, the steam is condensed and returned to the boiler to be heated once again.
According to IEA Clean Coal Center, the electric efficiency of older and smaller PCC plants can be as low as 30%. The average efficiency of larger, subcritical PCC plants is in the range 36% (steam pressures 165 bar and temperatures 565°C).

Supercritical PCC units take advantage of higher steam temperatures and pressures (pressures >250 bar and temperatures >565°C) to achieve higher efficiencies up to 45 % (recent supercritical plant in Denmark approach 50%). Application of new advanced materials to PCC power plant should enable efficiencies of 55% to be achieved in the future. The figure below shows Alstoms PCC output range.



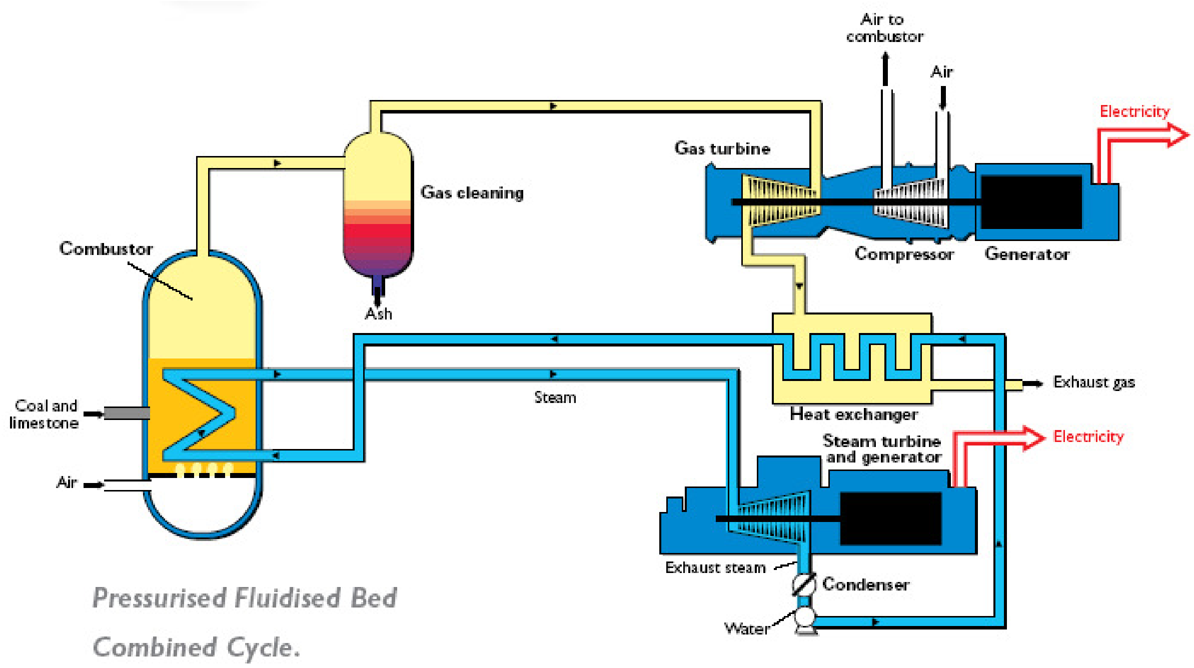
Source: www.power.alstom.com

Fluidised Bed Combustion (FBC)

Fluidised bed combustion is a method of burning coal in a bed of heated particles suspended in a gas flow. At sufficient flow rates, the bed acts as a fluid resulting in rapid mixing of the particles. Coal is added to the bed and the continuous mixing encourages complete combustion and a lower temperature than that of PCC system. The advantage of CFBC is the reduced NOx and SOx emissions. They can also use a wider range of fuels than PCC (low grade fuels, oil and biomasse). The efficiency of CFBC is similar to that of conventional plant.

Pressurised Fluidised Bed Combustion plants (PFBC) can achieve efficiencies of up to 45%. The high efficiency is achieved through a combi plant setup, where the pressurised combustion of solid fuels generates a combination of steam and hot pressurised flue gas which is used in a gas turbine.

Pressurised Fluidised Bed Combined Cycle power plant



Source:World Coal Institute web site: wci.rmid.co.uk

Integrated Coal Gasification Combined Cycle (IGCC)

An alternative to conventional coal combustion is coal gasification. When coal is brought into contact with hot steam and oxygen, thermo chemical reactions produce a fuel gas, largely carbon monoxide and hydrogen, which when combusted can be used to power gas turbines.

IGCC power generating systems are presently being developed and operated in Europe and the USA. These systems give increased efficiencies by using waste heat from the product gas to produce steam to drive a steam turbine, in addition to a gas turbine. The gasification technology opens for the use of coal, petroleum coke, heavy residual oil and other solid or low grade liquid fuels. Existing commercial systems achieve efficiencies up to 50%. General Electrics STAG 109 H system reports a net LHV thermal efficiency range of 49-51% for an installed capacity of 480-550 MW.

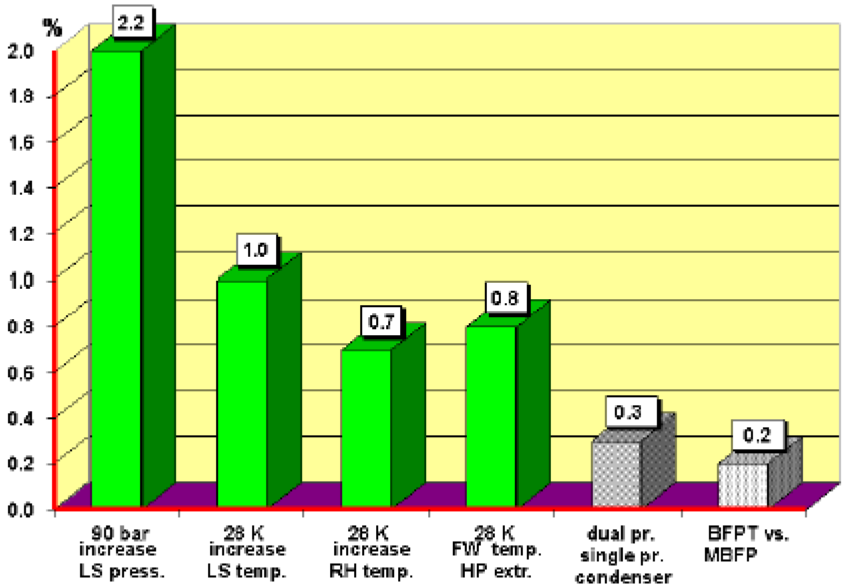
The table below provides a summary of the various technologies and their expected efficiency range when building a plant today.

Coal power plants technologies and performances

Power plant technology	Pulverised Coal Combustion (PCC)	Circulating Fluidised Bed Combustion (CFBC)		Gasification (IGCC)
System	Subcritical	Atmospheric	Pressurised	
Capacity	500 MW	250 MW	300 MW	300 MW
Efficiency at full load	*38 to 42 %* *(up to 45 %) (1)*	*36 to 45 %*	*Up to 48 %*	*Up to 50 %*
Coal used	All type of coal	Low quality fuel	Coal with enough reactivity	
Operation mode: Base load				

Alstom which is the manufacturer that has installed the largest number of coal fired designed steam turbines in the world, has made the following figure which shows efficiency gains made thorough improvements in steam pressure and temperature, reheat temperature, final feed water temperature, condenser pressure.

Relative efficiency improvement for coal power plants

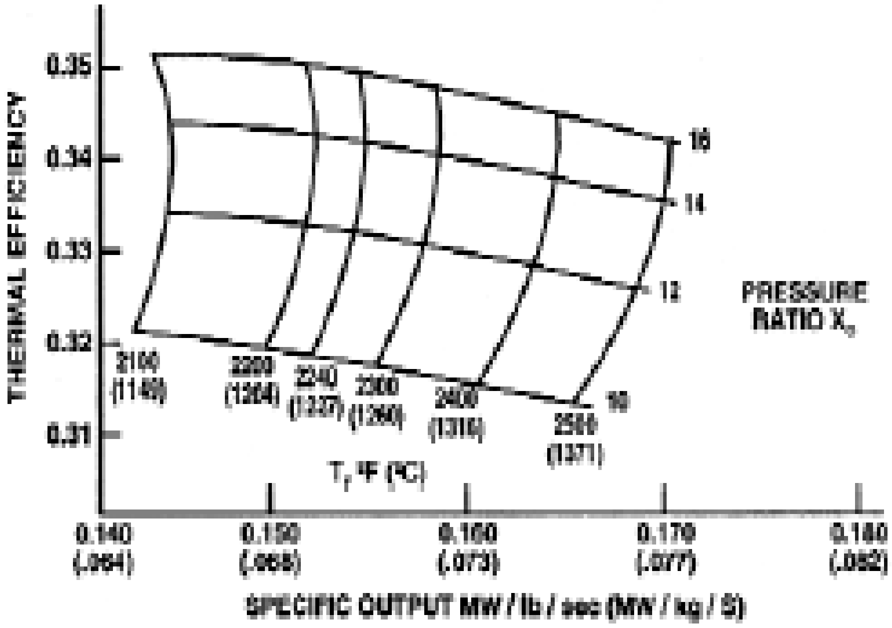


Source: www.power.alstom.com

Gas turbines - simple cycle

Better materials and technology has improved gas turbine efficiency substantially in recent years. Simple cycle efficiency above 45% can now be achieved. The graph below shows the relationship between efficiency and specific output of a simple cycle gas turbine:

Efficiency vs specific ouput for a simple cycle gas turbine



NB: the specific output is related to a constant air flow inlet.
Source: www.gepower.com

Gas fired - combined cycle

Combined cycle plants utilize the exhaust heat and include a steam cycle, thus combined cycle. Modern CCGT plants can achieve efficiencies of between 50-60%. The table below provides performance data for several CCGT plants delivered from Alstom, Siemens and GE. Only adapted GT for 50 Hz grid frequency are represented. The figures still represent a base load and full load operating mode.

Alstom CCGT performances

Model	KA8 C2-1	KA13 E2-2	KA13 E2-3	KA26-1
Power output	82,4 MW	495 MW	742.6 MW	410,3 MW
Efficiency	50,2 %	53.1%	53.1%	57,8 %
Heat rate (Btu/kWh)	6797	6426	6426	5903

Source: www.power.alstom.com

Siemens CCGT performances

Model	SCC-1000F	SCC5-2000E	SCC5-3000E	SCC5-4000F
Gas turbine	SGT-1000F	SGT5-2000E	SGT5-3000E	SGT5-4000F
Combined cycle	Single	1+1 multi	Single	Single
Power output	101 MW	247 MW	283 MW	407 MW
Efficiency	52,6 %	52,2 %	54,9 %	57,7 %
Heat rate (Btu/kWh)	6487	6542	6219	5915
Combined cycle	2+1 multi	2+1 multi	2+1 multi	2+1 multi
Power output	201 MW	497 MW	566 MW	814 MW
Efficiency	52,5 %	52,5 %	55 %	57,7 %
Heat rate (Btu/kWh)	6501	6497	6208	5914
ISO ambiant conditions (15°C, 1013 bar, RH (60%)). Fuel: natural gas.				

Single = Single Shaft (both gas turbine and steam turbine on the same drive train)
1+1 multi = (1 gas turbine + 1 steam turbine each turbine on its own shaft)
2+1 multi = (2 gas turbines + 1 steam turbine each turbine on its own shaft)
Source: www.powergeneration.siemens.com

GE single-shaft CCGT performances

Model	S106B	S106FA	S109E	S109EC	S109FA	S109H
Steam cycle	Non-reheat, 3-pressure	Reheat, 3-pressure	Non-reheat, 3-pressure	Non-reheat, 3-pressure	Reheat, 3-pressure	Reheat, 3-pressure
Power output	59,8 MW	107,4 MW	189,2 MW	259,3 MW	376,2 MW	480 MW
Heat rate (Btu/kWh)	7005	6420	6570	6315	6060	5690
Efficiency	**49 %**	**53,2 %**	**52 %**	**54 %**	**56,3 %**	**60 %**
ISO ambiant conditions (15°C, 1013 bar, RH (60%)). Fuel: natural gas.						

In the GE's STAG (for Steam And Gas) system designation, the first digit designates a single gas turbine and the third digit with the following letters designates the gas turbine frame size. For example, S 106FA is a one single PG6101 FA gas turbine.
www.gepower.com

Combi plants

Combi plants are combined GT and ST plants. Although the build up of combi plants can come in many shapes and forms, they can be generally be divided into two categories depending on their technical build up:

- ST based plants (Gas/Coal combi)
- CC based plants (Gas/gas combi)

ST based plants are basically coal fired plants with a GT addition. The GT is usually used for peaking purposes. The main part of the plant is thus the ST part.

CC based plants are CC plants with additional combustion in the boiler. Such plants are generally based on gas.

In both cases the gas turbine cycle and the steam cycle, usually can be operated independently This gives added flexibility both with regards to electricity and heat delivery.

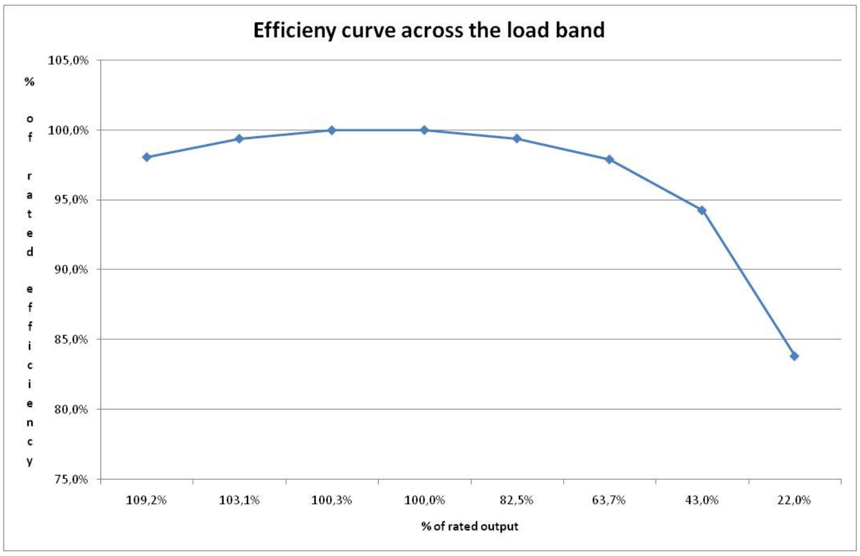
Efficiency across the load band

ADAPT has used actual data to develop formulas that can estimate unit specific efficiency at rated load. ADAPT has also tried to use actual data to approximate the average efficiency curve across the load band for different technologies.

Generally speaking one finds that modern power plants and upgraded plants have a higher degree of flexibility. In other words they have a flatter efficiency curve across the load band compared to older plants. Still, the actual shape of the efficiency curve depends on such a variety of unit specific conditions that it is difficult to estimate unit specific efficiency curves over the load band in the same way as rated load efficiency. Therefore one general efficiency curve has been made for each technology.

Below the typical efficiency-curve for a steam power plant is shown:

At 25% load the efficiency = 83% of rated efficiency
At 50% load the efficiency = 94% of rated efficiency
At 100% load the efficiency = 100% of rated efficiency
At 110% overload the efficiency = 97% of rated efficiency



Efficiency - Heat delivery

The efficiencies listed in the power plant list, do not include heat delivery effects. However, such effects can be included either on a unit specific basis using the "efficiency correction" column or on a general basis using the DH and BP factors.

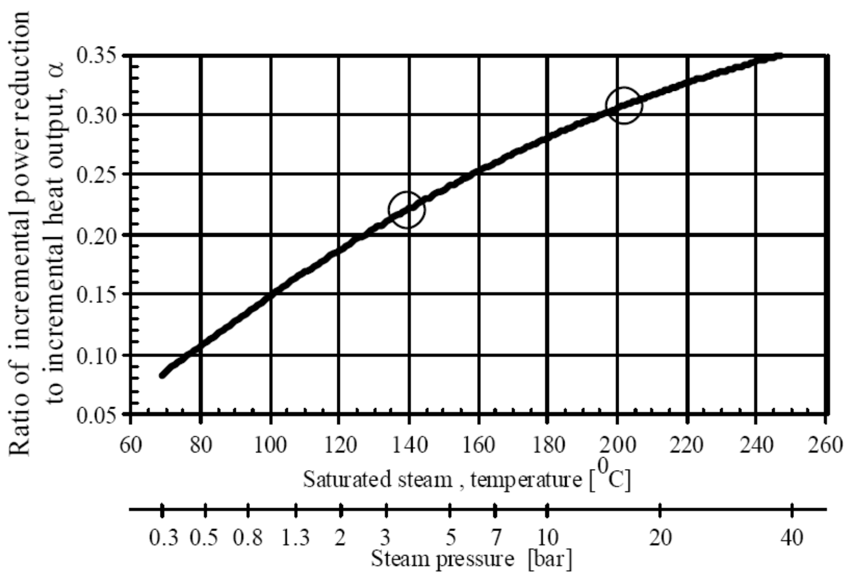
ST, CC and Combi plants that deliver both electricity and heat are called combined heat and power plants (CHP plants). In the power plant list the heat delivery is divided into two groups:

- District heating (DH)
- Back pressure (BP)

District heating units, as referred to in this report, provides heat for district heating or industrial purposes using the condenser. This will normally result in small efficiency losses. Another aspect is that district heating may not be delivered all year. Thus the reduced efficiency may only occur during parts of the year (winter). Studies show that shutting down heat delivery for a short period of time, in order to increase electricity production, will not have dramatic consequences for DH customers.

Back pressure units, extract steam/heat directly from the steam cycle, mainly for delivery to industrial consumers. This will generally lead to a larger efficiency loss, compared to extracting heat from the condenser. Also, back pressure heat deliveries are generally carried out all year around.

The graph below shows the effect on electric efficiency when heat is extracted from a steam cycle at different steam pressures. Taking out saturated steam at 100 degree Celcius cases a 15% reduced electric efficiency.



CHP plants can also be divided into two groups based on operational flexibility:

- Backpressure units
- Extraction

Backpressure units are generally inflexible in that they have a constant heat:electricity ratio. Extraction units on the other hand, can vary the amount of electricity and heat produced.

In addition to differences in technical flexibility, delivery obligations may reduce flexibility. In Denmark many power plants have up to 60% of their capacity linked to district heat delivery during parts of the year. Thus, regardless of power price, the electricity production must be kept at a certain level in order to meet heat delivery obligations. This can also limit the option of starting/stopping on a day to day basis during the winter seasons.

Heat delivery may also have an effect on production choices, since the marginal fuel cost can be divided between electricity and heat delivery.

Efficiency calculations

When developing the formula that would accurately estimate actual efficiency of different power plants, ADAPT found that age would be the best determinant. Technological development and efficiency is closely related and has developed relatively steady over the years.

On this background ADAPT used actual power plant efficiencies and age data to plot the units according to age, efficiency and type. Then a regression analysis was performed in order to come up with a linear formula which would accurately estimate a plants efficiency. The linear formulas that came out of ADAPTs calculations were almost identical to similar calculations made in other studies[4].

Below the formulas used to estimate the efficiencies are presented:

Lignite Steam plants

ST plants based on coal with fuel category 0 = lignite plants

Efficiency = (0,3144 x start year) – 584,91

Hard coal Steam plants

ST plants based on coal with fuel category 1 = hard coal plants. In order to determine a hard coal power plant's efficiency, we combined the formula which reflects the efficiency of all coal fired plants and the formula for lignite plants.

[4] Kugeler et al 1999: Entwicklung der Wirkungsgrade und Perspektiven fossiler und nuklearer Kraftwerke, Verein Deutscher Ingeniure.

Efficiency = (2 x ((0,25 x ((start year – 1920) / 80)) +0,2))) - ((0,3144 x start year) – 584,91)

Combi plants (gas/coal)

Gas/coal combi plants are estimated as lignite/hardcoal plants. However, there is a gas/coal combi factor which reflects the increased efficiency such a plant will have compared to an ordinary ST plant

Combi plants (gas/gas)

Gas/gas combi plants are estimated as CC plants, but with a gas/gas combi factor in order to reflect the reduced efficiency such a plant has compared to an ordinary CC plant.

Gas turbine

Efficiency = (0,0033 x start year) – 6,2833

Nuclear power plants

Efficiency = 33%

Combined cycle

Efficiency = (0,008 x start year) – 15,4

Other formula factors

All formulas include an "efficiency correction" element, in order to adjust calculated efficiency to actual efficiency where such information is made publically available.

For ST plants an oil/gas fuel factor is included to reflect the increased efficiency due to the use of oil/gas as fuel instead of coal.

The formulas for ST, Combi and CC plants gives good results until the year 2000. After this the linear formula overestimates the efficiencies. Thus an age factor has been included in order to correct the over estimation for plants build after 2000.

The formulas for ST, Combi and CC plants include a DH/BP factor in order to reflect efficiency losses due to heat delivery

Start/stop costs

ADAPT has used data from power producers and previous studies by Hanne Sæle[5], to develop a formula that will give a good approximation of the start/stop for the units in the power plant the list. For ST, CC and Combi plants the formula takes into account:

- Size of the plant - MW
- Startup time and fuel costs
- Startup conditions - Cold/warm start
- Type of plant - Coal or combined cycle plant

Below the method for determining the start/stop cost is explained.

Many thermal power units can be operated in standby mode. Standby mode means that the unit is kept close to operating temperature, without producing power. Standby mode requires energy to maintain temperature. Thus the cost of holding a unit on standby for a certain period must be compared with the start/stop costs.

Shutting down a power plant is generally associated with a fixed shutdown cost. This cost is determined as a percentage of the start/stop cost of each unit.

When starting a unit after a shut down, the unit will consume energy in order to reach operating temperature. Thus stopping and then starting a unit will incur costs depending on how long the unit has been shut down. In the power plants spread sheet this is estimated by using:

- Startup time (cold/warm)

- Minimum start load (which is the load at which the unit can start producing). For many plants this can be 20% of rated load. However, in order to include the calculated efficiency the minimum start load has been set to 25%

- Marginal fuel and CO2 cost at 25% load
- Startup load factor, adjusting for the fact that the unit will not consume energy equal to 25% of rated output during the whole startup period. A 100MW plant with a Startup load factor of 25% will thus have an average startup load of 6,25 MW.

- The scale factor is a fixed amount which adjusts for the fact that the start/stop costs is not a linear function.

The start/stop formula is as follows:

Unit size (MW) x Min startup load x Startup load factor x Startup time

This gives the total energy consumed during startup

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5 Sæle Hanne, "Power exchange between Norway and the Netherlands", Hovedoppgave ved NTNU, February 1998

Next:

Consumed energy during startup (MWh) x fuel and CO2 price / 25% load efficiency +/- scale factor

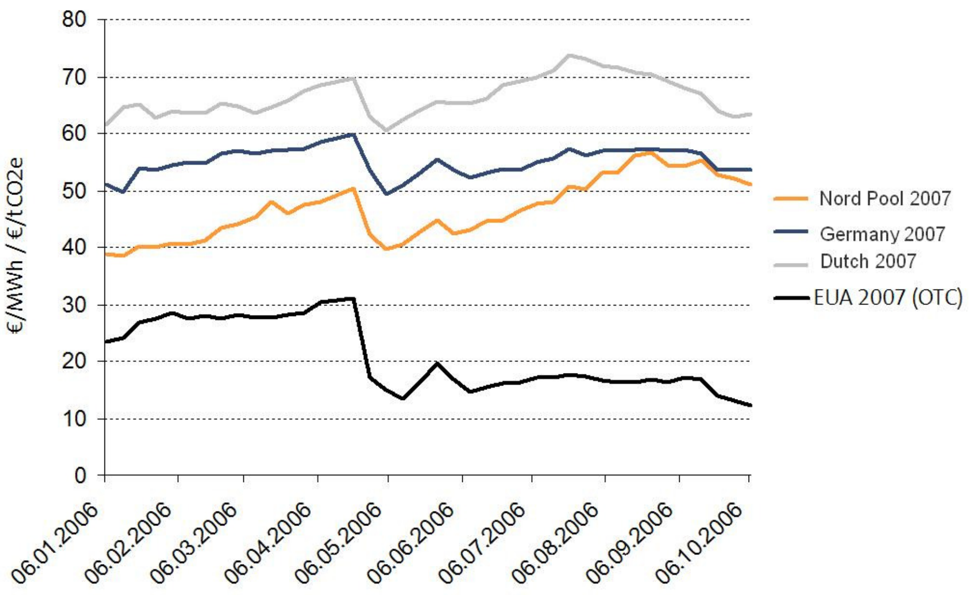
Gas Turbines have very low start/stop costs and thus a fixed startup cost per MW has been set for this type of turbine.

Nuclear power plants will generally not start/stop for other reasons than maintenance. Thus, in the power plant list no start/stop cost has been indicated for nuclear plants.

CO2- costs

From January 1st 2008 the EU CO2 trading system was implemented. This means that CO2-emmiting power plants must purchase CO2-quotas to compensate for their CO2-emissions. This means that the price of CO2 will added to the marginal price of power.

The graph below shows how the price of CO2 and the power prices in relevant markets have had a close correlation in the ETS test period 2005-2007.



Currently CO2-kvotas are priced at €20. At this price CO2-related power cost would be as follows:

Coal : 350 g/kWh => €7 /MWh
Oil : 300 g/kWh => €6 /MWh
Gas : 200 g/kWh => € 4 /MWh

The above numbers are not adjusted for efficiency. This means that a coal fired power plant with 40% efficiency would have an CO2-cost of €17,5/MWh (7 / 0,4). In the power plant list, CO2-costs are determined based on the emission numbers above, the CO2-quota price and the units efficiency at different loads.

Fuel costs

General

The power plant list included in WP2 includes units that use coal, oil, gas and uranium as their primary fuels. In many cases the plants can switch between fuel and thus are not bound to one type of fuel.

In order to determine the marginal cost of the units in the power plant list, primary fuel price assumptions have been made. Fuel prices are generally very volatile, thus the power plant list has been made dynamic, so that the effect of changes in fuel prices easily can be simulated. In the following a brief comment will be made on each fuel category.

It is important to note that European power producers often combine long term fuel contracts with spot market purchasing. Thus, using the fluctuating market price for a certain fuel may not give an accurate price reference on the actual fuel price witch the producer pays.

Oil

The graph below shows the price variation on NYMEX light sweet from 1994-2007. The volatile nature of the oil market is clearly illustrated.

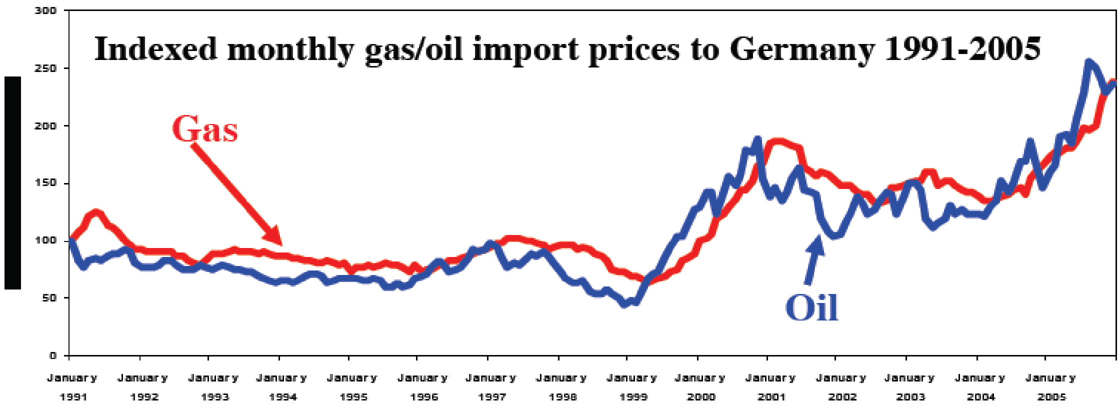
The oil used in gas turbines is often referred to as gas oil and not directly comparable to NYMEX or Brent prices. Generally gas oil will have a price which is USD 5-10 higher per barrel. Some steam based plants also use oil often referred to as heavy fuel oil. This type of oil is often very low grade and will typically be priced at about half the price of gas oil.

Oil is currently traded around USD 90 /bbl. This would imply a gas oil price of USD 100. This would again imply a gas oil price of approximately 40 øre/kWh and a heavy fuel oil of 20 øre/kWh, given 100% efficiency.

Gas

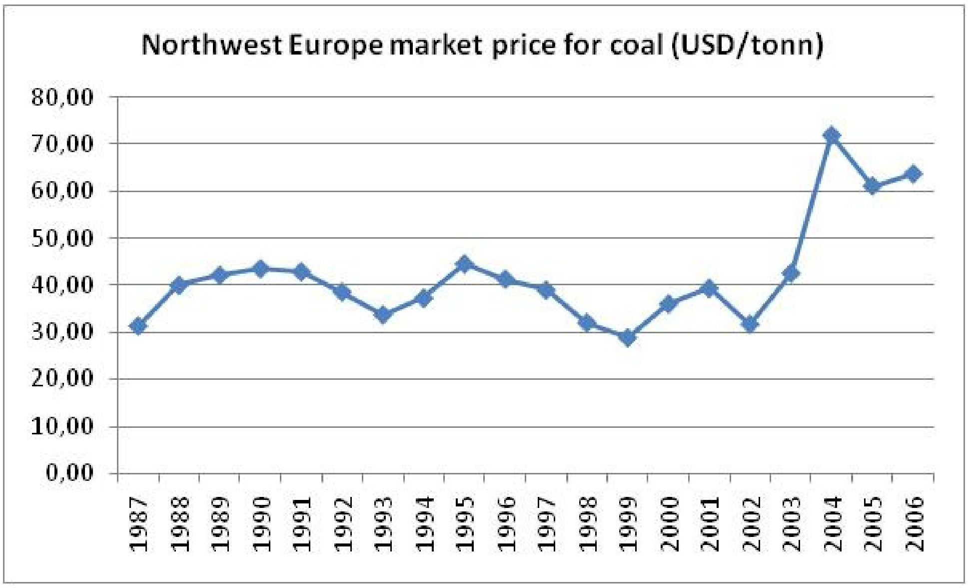
Natural gas prices are today closely linked to oil prices and have thus had a tendency to fluctuate closely with oil prices.

Natural gas is currently traded at about 52 pence/therm. This implies a fuel price of approximately 20 øre/kWh given 100% efficiency The graph below shows the indexed monthly gas and oil price to Germany for the period 1991-2005.



Coal

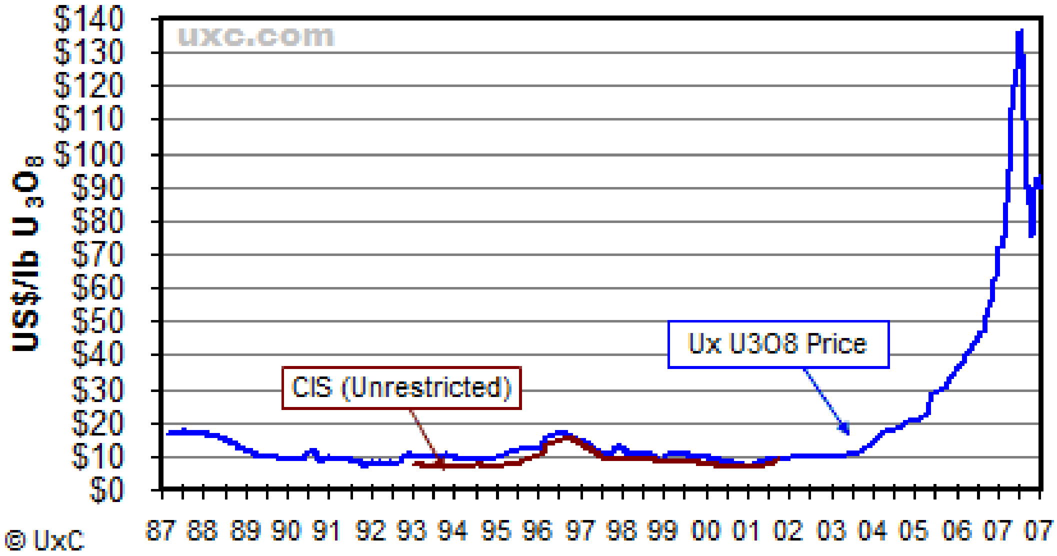
The graph below show the price fluctuations for coal in the Northwest European market between 1987-2006 (source: BP Statistical review 2007)



The last 5 years the price of coal has risen substantially. Currently the price of coal is around 130 USD/ton. However this price is expected to be lower for the year as a whole. Still, this price would imply a fuel price of approximately 10 øre/kWh given 100% efficiency.

Uranium

Due to the lack of capacity the price of fissile fuel has risen substantially the last 5 years, as the graph below shows. However, it is expected that this will change within 2010 when a number of new mines will open. The current price of U3O8 is 90 USD/lb. This implies a fuel cost of approximately 2-3 øre/kWh given 100% efficiency.



Operating modus

General

Although most power plants can start/stop production and adjust their output up/down in order to deliver balancing reserves from a technical point of view, some plants are more relevant as balancing reserve providers. Thus, when modelling it can be useful to make assumptions concerning the operational mode that specific power unit is operating under at different points in time. Several different modes and operational options could be chosen, however a sufficient division would be to divide the operational modes into four:

Mode 0

In mode 0, the power plant is offline due to maintenance and revisions. Most power plants have a yearly revision, which often is done during the summertime. Most power plants will thus be in operating mode 0 during a year.

Mode 1

Power plants that operate in mode 1, operate at maximum production Pmax. This operating mode does not allow deviations from Pmax, unless it is technically necessary. Most nuclear power plants will operate in mode 1 as base load capacity. Thus, these units will be less likely to participate with balancing reserve capacity.

Mode 2

In mode2, the power plant will be in constant operation (no start/stop), but will adjust production up and down the load curve within the Pmax / Pmin bandwidth. Mode 2 is relevant for many plants that have heat delivery obligations, and thus cannot start and stop the plant. Mode 2 is thus mostly relevant during wintertime where the heat delivery is constant. During the summer, district heating may be shut down and thus allowing a more flexible operation.

Many Danish power plants will have 60% of its capacity bound to heat delivery. This means that they must be in constant production and can only operate between 60% capacity and 100% capacity.

Mode 3

Power plants operating in mode 3, can and will operate across the entire operating bandwidth between Pmin and Pmax. In addition this operation mode opens for starting/stoping the power plant. Thus mode 3 is the most flexible operational mode.

Ramping rate

The ramping rate is the rate at which a power plant can increase/decrease its output. The ramping rate will vary from unit to unit. The list below gives a typical overview of ramping rates for different types of power plants:

- Oil/gas fired 8 % nameplate/min
- Coal fired 4-8 % nameplate/min
- Nuclear 5-10 % nameplate/min

Technically it may be possible to achieve higher ramping rates. However stress on vital components and equipment will often limit the actual ramping rate.

6. Reserve costs – large consumers

Demand vs. generation, and small consumers vs. big consumers

Demand side balancing resources differ from generation resources in several ways:

- Consumers are not in the energy business
- They are generally smaller than generators, and with other obligations than adapting to the energy market or load situation
- The number of categories is much higher than in generation and the ability to offer reserve capacity, even within the same kind of industry may vary over time
- While generator reserves have decreasing costs over time, demand increases its costs over time

This does not imply, however, that demand cannot in some cases offer better and even cheaper balance services. Another important property is that demand can offer more load balancing the higher the load is.

The limit set in this report is demand beyond 25 MW. It should, nevertheless, be mentioned that reserve capacity is and will increasingly be offered by even quite small consumers. These opportunities are, however, more grid owner and equipment producer initiated and operated. Example: Two-way communication makes automatic load balancing more realistic and interesting. Applications may be air-conditioning, space heating, water heating, freezers, refrigerators etc. This is an area where a lot of innovative ideas are launched, for instance utilising the battery capacity of electric cars not in operation.

Even if these opportunities are not a part of this analysis it should be mentioned that they may have some important properties compared to bigger consumers.

- They may be activated instantly without any pre-notice
- Since the number of participants is high they may as a group be more reliable than bigger consumers
- Even if consumers with smaller loads are allowed to override a shut down, it does not necessarily reduce their value, because their statistical reliability can be calculated

Even if such smaller loads may supply system services, ability to do so systematically indicates that these loads are attractive for use on a more regular basis, responding to daily load curves, rather than being used as reserves for instant system services. Even though analyses may show that applying these loads for regular “load shaving” purposes is preferred, the situation may change. This might be the case if for instance two-way communication is generally applied. Technology may make it possible and interesting to rank small consumers demand. Some of the demand may be suitable for system services, while other applications may remain as more suitable for “load shaving”.

To what degree is the potential already utilised?

There are already several mechanisms that activate and utilise the demand side balancing resources

- The RK market
- Various options with pre-notice
- Ordinary load management initiated by transmission and load tariffs

If any of these mechanisms are already utilised at a particular moment additional potential may be limited. In addition there may be a conflict between other means of adjusting load and the wish to limit deployment time to be ready for the next contingency. If a demand has been out or reduced for some time, it may be critical to be back in production to avoid escalating costs.

A good example is the aluminium industry that can offer significant volumes, but also face absolute limitations as to how frequent and for how long reduced load can be offered.

When looking at the price and incentive structure, for instance for load management, tariffs are normally not specifically designed for the purpose of this study, i.e. to reflect the value of the services in question.

Electricity tariffs often reflect that the grid costs to a large degree are fixed and the tariff should distribute the firm costs in a fair way. Practice, even within a country varies a lot, for instance: Customers pay according to

- maximum load during the year
- average of two or more of the highest loads during the year
- average of winter loads (may be summer loads if system maximum load should occur during the summer)
- higher or lower fixed price for peak and off-peak periods

In addition also energy prices are often promoting load management; for instance: peak hours are more expensive than off peak hours.

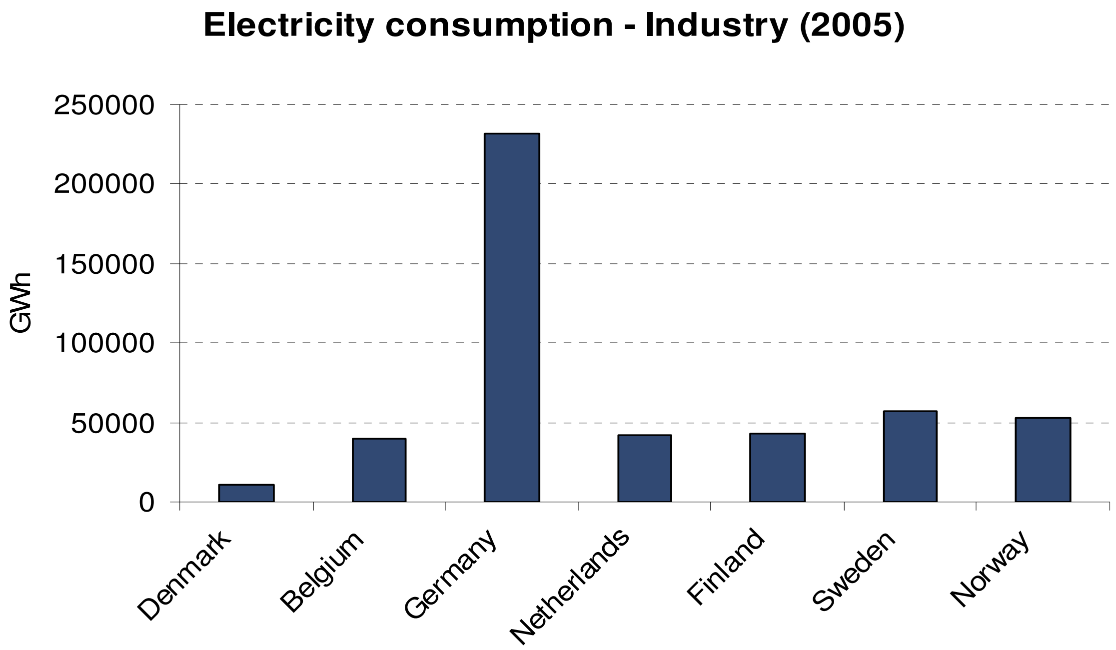
To obtain system service offers tariffs and rules must be more performance specific. Designing an incentive system along with administrative support to handle the opportunity in practice seems to be the key to success.

Along with the need for an adequate incentive structure, the potential as well as the cost of demand side system services is to a large degree a question of developing the potential. Like for production, some investments may be needed to make customers able to offer the services in question. But since the consumers are not first of all focused on energy, management recourses are required and training programs are needed. It may be a good idea to provide these kinds of activities as a part of the incentive program. It is likely that only a fraction of the potential is actually activated today.

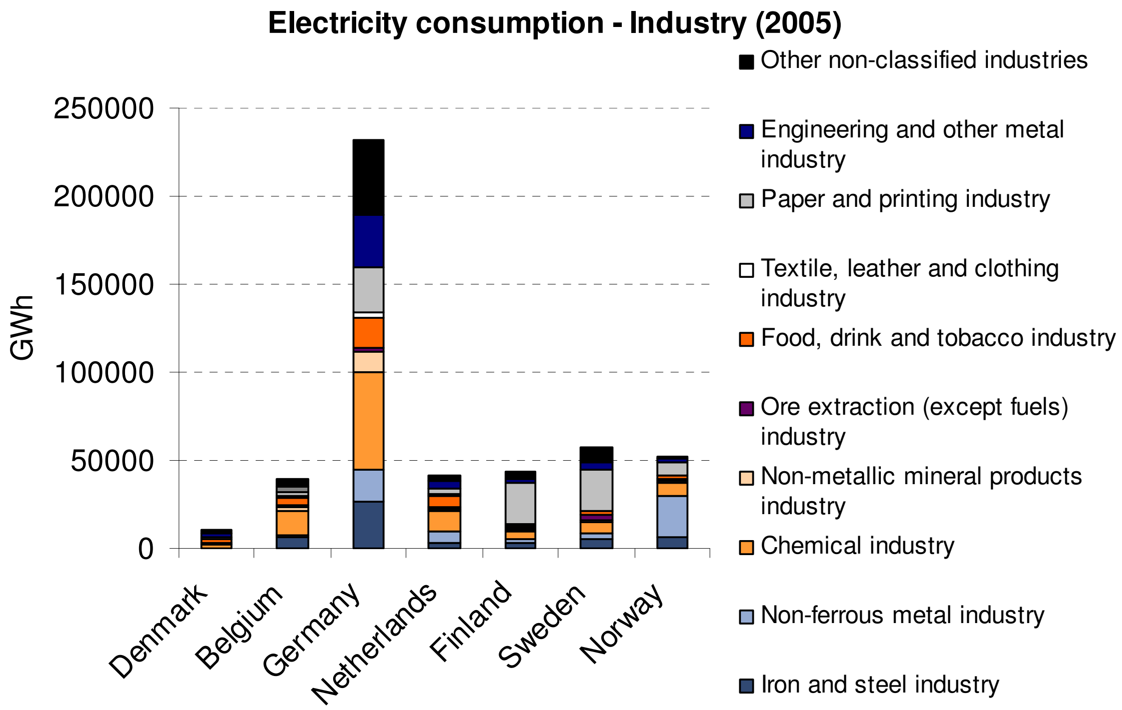
The potential for demand side system services

The figures below show electricity consumption in industry in the chosen countries, in total and by sector. Total consumption is 475 TWh, of which approximately 50 % in Germany. The corresponding load is estimated to be approximately 100 000 MW.

There is no exact statistics showing how much of this is with consumers above 25 MW, but our estimate is approximately 20 000 MW. This figure may seem surprisingly low, but it should be taken into account that the biggest consumers of electricity also are those with the highest utilisation time, often 7 – 8 000 hours. Their share of the consumption is thus higher.



Source: Eurostat



Source: Eurostat

If we look at the various industrial sectors, some obviously offers more opportunity than others. Important contributors may be metallurgical and chemical industry, and to some degree pulp and paper industry and non-metallic mineral products. In other industries there might be contributions, but electricity in these industries more frequently is an input factor that cannot be shut down or reduced without harming the total production and profitability.

The estimated distribution of the 20 000 MW with a unit size above 25 MW is shown in the table below. It is an interesting observation that among these countries Norwegian industry has the relatively highest potential to offer system services, due to the high share of electrochemical and electrometallurgical industry. To what degree this potential increases the ability of Norway's hydro production to offer even more system services is an important question, although beyond the scope of this study.

Country	Total industry load Unit size > 25 MW	Estimated Available for System Services (MW)
Denmark	0	0
Belgium	1 300	400
Germany	10 000	4 300
Netherlands	1 500	400
Finland	1 400	600
Sweden	1 800	800
Norway	4 000	3 500
Total	**20 000**	**10 000**[6]

(ADAPT estimate)

Each industrial sector has some specific characteristics and applies electricity for particular purposes. In addition, within every sector there are variations. Most industries can reduce some demand, but often it is essential to remain with a considerable supply. Consumers with a total load below 25 MW may in many cases, as indicated earlier, be able to reduce more loads at a lower cost than bigger consumers. Bigger loads are easier to monitor, smaller loads may be more reliable.

Our evaluation is that more than 75 % of the estimated potential of 10 000 MW is already exposed to load management or system services. There is no information or statistics concerning the distribution between load management and system services. While load management can be initiated either by the customer or the system operator, system services can only be initiated by the system operator. The present incentive structure, that is included in the broader scope of the project, indicates that load management initiated by the customer represents the major part of the volume. To make these loads available to system services rather than load management, a different incentive structure needs to be developed.

Even customers with a potential to reduce load above 25 MW may in practice want to reduce only a part of their total load. Independent of the size of the system service that may be offered there are two main challenges in utilising these opportunities

- Installation of necessary technical equipment

[6] More than 75% of this volume is already exposed to load management. Load management and system services may be competing products.

- Routines and administrative systems to implement a load reduction with no or minor consequences, including safety

If we look at the different sectors specified above, most opportunities seem to be available in the

- Iron and steel industry
- Non-ferrous metal industry
- Chemical industry
- Paper industry
- Food industry (to some degree)

It is obvious that electrometallurgical and electrochemical industry have the biggest volumes to offer per unit, if and when production can be halted. Our estimate is that as much as 10 000 MW may eventually be available for system services in the listed countries, and at a relatively low cost, see table on previous page. But that will to some extent reduce load management.

We have interviewed a number of industrial companies about their ability to offer system services within the 15 minutes period. Here are some of the points that were emphasized:

- *Load management* is at present important to all kinds of industry, not at least in industries that are not particularly interested in offering system services. They are able to reduce the load, but with today's incentive structure it would be a coincidence if their load response is in line with the system needs. Since the load management system is economical without system services, the same system could be employed with a different incentive system at no extra cost. However, it is again a question whether this kind of opportunity "belongs to" the system services or regular load services. That obviously depends on the cost of alternative system service sources.
- *Security* is a concern. Industrial processes can imply a risk if they are halted, and at least the routines and management systems should be in place.
- *Pre-notice* is always welcomed, because it reduces the risks and also the likelihood of external costs from the event. Very often even a pre-notice of one or two minutes are welcomed. After that load can often be taken down immediately. The opportunity to override a shut down may be vital. An example could be the ferro-alloy industry, where a cut in supply of electricity during tapping could be very dangerous. Communication is mentioned as important by everyone.
- *Other considerations*. Industry would evaluate the opportunities according to the production process, employees, customers, logistics, agreements and how the society values their participation

Costs related to system services in demand can be regarded in different ways. Since an electric black out is something that industries should be prepared for, a voluntary system has by definition a low additional cost. To the extent that specific measures have to be taken we basically talk about three cost categories:

- Investment costs related to technical equipment
- Management operating costs
- Costs due to lost production

- Costs due to reduced quality, damage or increased risk of damage on production equipment

It goes without saying that the more often system services is delivered, the lower is the investment cost per unit of service. Management operating costs are partly fixed (Industrial plants in question have to be prepared.) and partly depending on the services actually delivered. Risk of damage depends on the frequency and length of halt in production and varies from industry to industry.

Short on specific industries

Aluminum

Large volumes can be offered within the period of 15 minutes at low additional cost in most plants. Systems and management resources are to a large extent already in place. The market price of aluminium could represent for instance 110 - 150 €/MWh. The cost of system services is defined by the value of lost production, market price of electricity, the possibility of compensating lost production, transmission tariff consequences and power contract restrictions. Duration: 2-4 hours.

Steel, Ferro-alloys, Silicon, Ilmenite

Security is an important concern. There are few problems and low additional costs once it is proven possible to halt production. Length of interruption decides the actual costs, not at least because the risk of destroying electrodes increases by time.

Zink, Nickel

Parts of the production is sensitive to interruptions. For Zink a parallel production of aluminiumfluorid causes possible problems linked to emissions of CO_2. Not the first place to look for system services.

Pulp and paper

Pulp production is a possible candidate to the degree that electricity is applied, particularly with thermo mechanical production. Electricity in the pulp and paper industry is mainly used for engines that are generally not available for system services. Even with big consumers, only fractions of the consumption may be interrupted.

Food industry

Electricity for heating purposes is mainly a Nordic phenomenon. Cooling and freezing offer considerable opportunities, but may not be available as a system service because it is already utilised on a regular basis.

Chemical industry

The range of chemical industry is so wide that it is impossible to generalise. Considerable volumes may be available in many plants, while complex chemical processes make system services very expensive in other plants.

How economically interesting is System Services for electricity intensive industry?

The table below shows the situation for some of the most electricity intensive products. These are products with a potential to offer the most significant volumes per unit. These are also the products that can take the highest costs to make system services available.

One should be aware of the fact that electricity intensive industry is traditionally faced with volatility both in the electricity market and in the market for their end products, which has a significant impact on their system service cost.

Product	Market price December 2007/ January 2008 US$ per 1 000 kg	Market price December 2007/ January 2008 €/kg (€/$=1,5)	Electricity consumption per kWh/kg	Market price €/MWh consumed
Aluminium	2 400	1,60	14	114
Ferrosilicon	1 400	0,93	9	103
Ferromanganese	1 600	1,07	2	535
Silicomanganese	2 700	1,80	4,5	400
Nickel	28 000	18,67	6	3112
Zink	2 400	1,60	4	400
Silicon metal[7]	1 600	1,07	14	76

Source: London Metal Exchange, various sources

It goes without saying that producers of aluminium, ferrosilicon and silicon metal probably have more incentives to look into the opportunities of system services than for instance producers of nickel. However, the important question is what it requires to offer system services compared to the cost. If there is a margin that is interesting there is a potential. The challenge may be to draw attention to the potential.

Cost equations

The reserve costs for large consumers include several elements:

1. (I): Investment in necessary equipment
2. (M): Management
3. (El): Energy losses
4. (Pl): Production losses

[7] Price refers to supply of bulk delivery.

5. (D): Damage on products and equipment
6. (S): Saved energy
7. (Pc): Power contract consequences
8. (Rc): Residual costs

Investment in necessary equipment (I) and to a large extent also management (M) is relevant only in the initial phase. Once a customer decides to be prepared to offer system services (I) and (M) may be regarded as sunk costs and should not be included in the marginal cost equation.

Power contract consequences (Pc) are included first of all as a matter of order. Some power contracts specify a utilisation time, for instance 8000 hours. (Utilisation time is defined as energy divided by maximum load in the contract, for instance 80 GWh/10 MW = 8 000 hours utilisation.) Contracts may also have special rules for energy that is not used as to how it is compensated. It might be that the customer is allowed to sell the power in the market or that he simply only pays for utilised energy. If he is allowed to sell, there may be different rules of how that should be handled, varying from contract to contract. We have assumed that the energy saved can be sold in the market at present market price.

This means that the general cost equation defining marginal costs of system services offered by large consumers can be defined like:

Marginal cost (Mc) = (El) + (Pl) + (D) – (S) + (Rc)

Energy losses **(El)** are generally linear with time. When production is halted, thermal energy is continuously lost as a function of time. The range of temperature is normally narrow. However, available time to supply system services may be limited. In production of aluminium for instance, halting production beyond 2-3 hours implies that all are freezing, and costs become prohibitive.

Production losses **(Pl)** are normally a combination of lost sales and the fact that a significant part of production costs remain unchanged. (Capital costs, employees, logistics etc., while some raw material costs are saved). It is important to note that normally production losses do not only occur in the specific period when the customer supply system services. When normal electricity supply is restored it normally takes some time to be 100 % back in production.

Damage on products and equipment **(D)** is normally expected to increase with the length of the supply period. The figures are difficult to estimate exactly and normally a calculation of probability is required. In the aluminium industry, as an example, there is a risk of freezing along with an increased probability of damage on the melting furnace. These costs may be prohibitive. In the ferroalloy industry breakage of electrodes is a similar risk with increased probability.

Saved energy **(S)** can normally be regarded as an income, reflecting the market price of electricity at the time of supplying system services. In the most electricity intensive industries, like aluminium and ferroalloys there are several examples of consumers selling their energy instead of producing. However, this is rarely defined as a system service. Production is halted because selling a power contract in the market is more profitable than producing the basic product. In fact consumers in this situation cannot offer system services at all.

It should be mentioned that the assumption that saved energy can be sold in the market at present market price requires that the particular customer in question has quoted a specific load in the market and is exposed to the market for quoted and realised consumption.

Residual cost **(Rc)** contains every cost and inconvenience as it is valued by each customer. Inconvenience is an important term in this respect. Most consumers feel that their organisation is slim, they lack resources and there are several things that can be addressed to improve the overall economy. A frequently observed attitude is that "We might do something here, but it is not worth it. There are so many other things that we either have to or ought to do."

This explains why with many potential customers it would require a more or less automatic system that is easy to administrate and activate.

In order to demonstrate the real meaning of the factors above, aluminium, which may be an important contributor, is used as an example.

Example aluminium

Assumptions:

- Figures refer to 1 aluminium cell, producing 50 kg/h
- Power consumption in full production: 14 kWh/kg, equivalent to 700 kWh/h ref one cell of 50 kg/h, of which 320 kWh/h is chemically absorbed in the aluminium and 380 kWh/h is equally (50/50) distributed between heat losses and tail gas/off gas. This means that heat loss that must be compensated is 380 kWh/2 x length of duration of reduced power supply (380/2/2 = 95 kWh for a 30 minutes stop in supply)
- Aluminium oxide: Cost 25 €/h (consumption 1,93 kg per kg aluminium)
- Power contract cost: 25 €/MWh
- Power market price 50 €/MWh
- Aluminium price 2400 $/tonn equivalent to 1600 €/tonn, equivalent to 80 €/h
- OPEX (operating cost excluding capital cost): 55 €/h
- Duration (total stop due to supply of system services): 30 minutes
- CO_2 emissions: 1,6 kg per kg aluminium: (Not explicitly included in the calculation, but that may be relevant)
- Loss of production: In proportion to stop duration, 25 kg per 30 minutes, + 1-3 % of production, depending on circumstances. Assumed 2 %, equivalent to 1 kg for a 30 minutes stop.
- Net production with 30 minutes stop: 24 kg/h

Calculation 1: Normal production 1 hour

- Total income: 80,0 €
- Oxide cost: 25,0 €
- Power cost: 17,5 €

- Capital cost: 25,0 €
- Other costs and profit: 12,5 €

Calculation 2: 30 minutes stop

- Oxide cost: 25 x 24/50 = 12,00 €
- Power cost: (700/2 + 95) x 25 = 11,13 €
- Capital cost: 25,00 €
- Other costs and profit: 12,50 €
- Total costs: 60,63 €

- Income sale of aluminium: 24 x 1,6 = 38,40 €
- Income sale of power: 700/2 x 50 = 17,50 €
- Total income 55,90 €

This implies that the aluminium producer needs an extra income of 60,63 – 55,90 = 4,73 € , equivalent to 4,73/(700/2) = 13,5 €/MWh to be indifferent between supplying system services or not.

As can be seen from the assumptions in this calculation the assumptions concerning product prices and power prices change the system service cost considerably. For instance for a 30 minutes period

- 10 % increase in aluminium price gives a system service cost of 8,89 €, equivalent to 25,4 €/MWh
- If power costs increase by 20 % (5 €/MWh in the example) and power market price remains unchanged the system service cost is 6,95 €, equivalent to 19,9 €/MWh
- If power contract price and market price for power is identical, for instance 50 €/MWh, system service cost increases to 15,85 €, equivalent to 45,3 €/MWh
- If power contract price and market price for power is identical, for instance 50 €/MWh, and product price increases by 20 %, system service cost in our example would be € 7,50, equivalent to 21,4 €/MWh

The important conclusion is that relatively moderate and realistic changes in assumptions have a considerable impact on the result. Also other input costs may of course vary and have an impact. It therefore goes without saying that there is no fixed and stable system service cost related to big consumers.

If we should try to establish an overall and long term picture a few things should be specially focused:

- A lot of the major potential suppliers of system services on the demand side have to a large extent enjoyed favourable power contracts, compared to the market price of power. The opportunity to sell power at a profit when out of production is, as demonstrated above, important to their marginal cost of stopping. These favourable power contracts may soon belong to the past. However, increased product prices, partly related to increased power costs, may to some extent compensate for the loss of power price margin.

- The ability to supply system services is as mentioned earlier in many respects dynamic by nature. That means that in addition to the economics of input, power and product prices, the technical and necessary equipment basis can be developed. To do so a special price incentive structure may have to be developed. Such an incentive structure will to some extent be a "competitor" to traditional load management.

In the table below the distribution of available system services are estimated, country by country. The basis for the estimate is the distribution of industries in the various countries, typical industry technical opportunity and interviews with a number of technical management staff in various industries.

The loads with the lowest system service cost seem to be correlated with industries with the highest utilisation time. High utilisation time means that you cannot gain much from load shaving. This implies that traditional load management is more important to those with the highest system service cost. The higher the system service cost is, the more likely it is that load management is more profitable than system service supply, and again: Tariff structure may decide.

Estimated distribution of System Service costs. MW

Country	Total estimated available for System Services	< 30 €/MWh	30 – 60 €/MWh	> 60 €/MWh
Denmark	0	-	-	-
Belgium	400	100	150	150
Germany	4 300	1 300	1 500	1 500
Netherlands	400	100	150	150
Finland	600	200	200	200
Sweden	800	200	300	300
Norway	3 500	2 700	300	500
Total	**10 000**	**4 600**	**2 600**	**2 800**

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8. Appendix – List of power plants

SEE ATTACHED EXCEL FILE