Local CHP Plants between the Natural Gas and Electricity Systems

Lars Bregnbæk & Camilla Schaumburg-Müller

Informatics and Mathematical Modelling
Technical University of Denmark
Richard Petersens Plads - Building 305
DK-2800 Kgs. Lyngby, Denmark

Abstract

Local combined heat and power (CHP) plants in Denmark constitute an important part of the national energy conversion capacity. In particular they supply a large share of the district heating networks with heat. At the same time they are important consumers as seen from the gas network system, and they contribute significantly to the electricity production. CHP is, together with the wind power, the almost exclusive distributed generation in Denmark.

This paper deals with the CHP as intermediary between the natural gas system and the electricity system. In particular, the relationship between the peak hour characteristics of the electricity and gas systems will be investigated. The point is here that the two systems will tend to have peak demand during the same hours. This is the typical situation, since load is high during the same hours of the day and of the year. Moreover, the random variations in the load will be correlated between the systems, because both demands in part depend on the climate.

The analysis in the paper is based on a numerical model which simulates the operation of a CHP plant with heat storage. The conditions for the operation of the plant are assumed to be consistent with the conditions that are expected to be in force in Denmark during 2005, where a large part of the local CHP plants will change from being paid for electricity production according to a feed-in tariff, to a situation where the electricity is to be sold on market conditions. The results will highlight the CHP plant as the link between three energy supply systems, viz., district heating, gas and electricity.

1 Introduction

In Denmark, three energy systems form a very interesting and interconnected structure. Natural gas has become a key primary source of energy for both electricity generation and, both directly and indirectly, for heating purposes. The electricity and district heating systems meet in combined heat and power (CHP) generation facilities, of which most are natural gas fired, at locations all over the country.

Denmark has since 1982 extracted increasing amounts of natural gas from the North Sea of which much is used for electricity and heat generation purposes. Electricity generation by local CHP facilities commenced around 1990 and has, due to government subsidies, steadily increased ever since, only slightly tapering off in recent years. Local CHP capacity increased from roughly 200 MW in 1990 to nearly 2.5 GW in 2000. Most local CHPs started out as pure heat production facilities, constructed for the sole purpose of meeting the local heat demand. As they have been converted to combined heat and power generation they are thus direct connection points of the three energy systems.

This paper considers precisely this interconnection, and attempts to illustrate the consequences of recent legislation which imposes that local CHP facilities must now operate on market terms when unloading generated electricity. In Sections 2 and 3 the three energy systems are described. Section 5 describes the modelling procedure and in Section 6 simulations are presented which illustrate the situation. Finally, Section 7 contains discussions and conclusions.

2 The Natural Gas System

The Danish supply of natural gas originates in the off-shore oil and gas fields in the North Sea. Two high pressure pipelines extend along the sea bed and make landfall in Jutland. They meet at the Nybro gas treatment plant near the western coast of Denmark (see Figure 1) where up to 24 million cubic metres (energy content roughly equal to 1000 TJ) of gas can be treated daily. From Nybro two 30 inch transmission lines extend across Jutland towards the major junction at Egtved.

From here one connection goes south to the Danish-German border at Ellund. Another goes north to the gas storage facility at Lille Torup and terminates in the city of Aalborg. Finally a transmission line runs all the way East across the country, passing Odense and crossing both "Belts" to arrive on the outskirts of Copenhagen near Karlslunde. From here one line proceeds to the Stenlille storage facility while others produced to supply the area of Greater Copenhagen and the northern parts of Zealand and ultimately a transmission line crosses Øresund to supply our Swedish neighbours.

Figure 1 The Danish natural gas transmission system (image source: Gastra A/S)

Most of these major transmission lines are 20-30 inches in diameter and scaled to a maximum pressure of 80 bars. At no place in the transmission network is the pressure allowed to descend below 42 bars in order to secure adequate pressure at the final delivery locations. Along the transmission network are metering and regulation stations (M/R stations). From here, natural gas is pulled from the transmission system into the underlying distribution networks. Here the responsibility for network operation is also passed from the transmission system operator Gastra [9] to one of the four distribution system operators.

These operators, along with the storage system operator, are public companies responsible for providing the basic services of natural gas supply. Each company has an economic structure for financing their operations. They develop products for capacity and volumetric throughput in the system and provide balancing services. The model used in this article is a reflection of present and previous structures with regard to the services available to the gas transporter.

3 The Electricity and District Heating Systems

3.1 The Electricity System

The Danish electricity system is at present separated into two systems by the Great Belt between Funen and Zealand. The western and eastern regions each have their own independent transmission system operator (TSO) - Eltra and Elkraft-System, respectively - yet recent legislation [8] has decreed that the two unite with Gastra into a single TSO (to be called EnergiNet.dk [6]) with responsibility for the entire Danish electricity and natural gas system.

There are international connections from the western system to Germany, Norway, and Sweden, and from the eastern system to Sweden and Germany, but the two Danish systems are not (yet) interconnected.

The majority of the electricity production stems from either large central plants, wind power, or local CHP plants of sizes ranging from a few kW to around 400 MW. The change in the composition of the national electricity production capacity from 1983 to 2003 is shown in Figure 2.

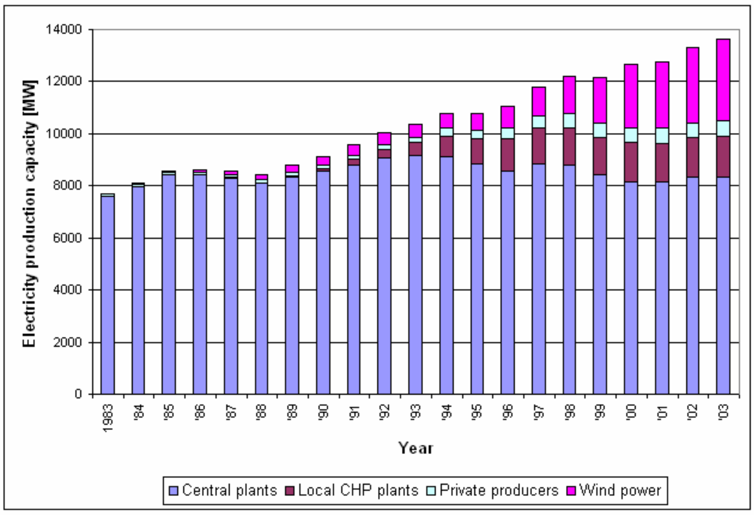

Figure 2 Change in composition of electricity production facility types (source: Danish Energy Authority [7]).

3.2 The District Heating System

In Denmark, heat demand varies considerably over the year, with minimum during the months of July and August and peaking from December to February with significant diurnal and weekly variations.

The heat produced stems from large central CHP plants, local CHP plants, district heating plants, and private producers, as illustrated in Figure 3.

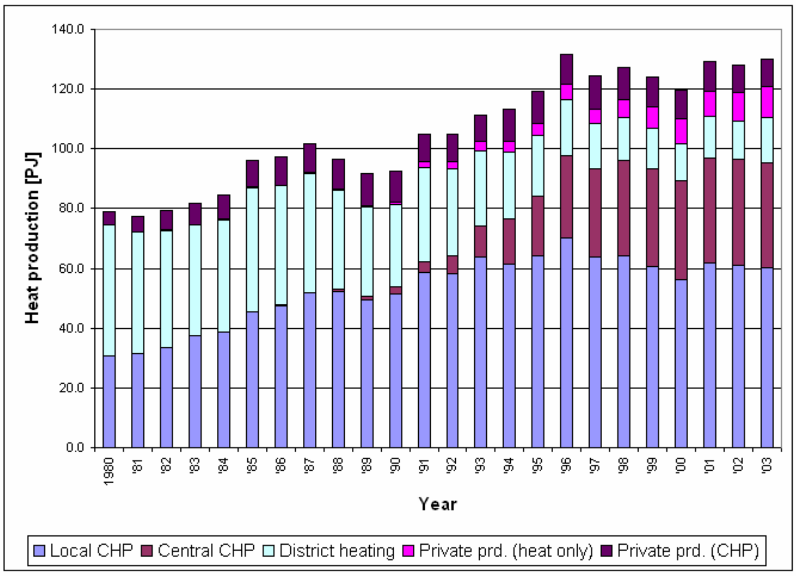

Figure 3 Composition of heat production from 1980 to 2003 (source: Danish Energy Authority [7])

As may be seen from the figure, the majority of the heat production takes place at the large central CHP plants. However, the share of production handled by district heating has decreased significantly as many of these facilities over time have been converted to local CHP plants.

3.3 Local Combined Heat and Power Plants

Combined heat and power plants began to emerge in Denmark in the late 1980's and attributing to government policies and subsidies the amount of facilities grew steadily during the 1990's. The principal idea was that heat production units that supplied the district heating systems around the country should be replaced by CHP facilities where heat was merely a fortunate by-product of electricity generation. Most were also equipped with heat storage facilities, which to a certain degree made possible the production of electricity even when the heat demand was satisfied.

Until 2005, electricity produced at local CHPs was prioritised and sold according to a feed-in tariff, the so-called three stage tariff (see Figure 4).

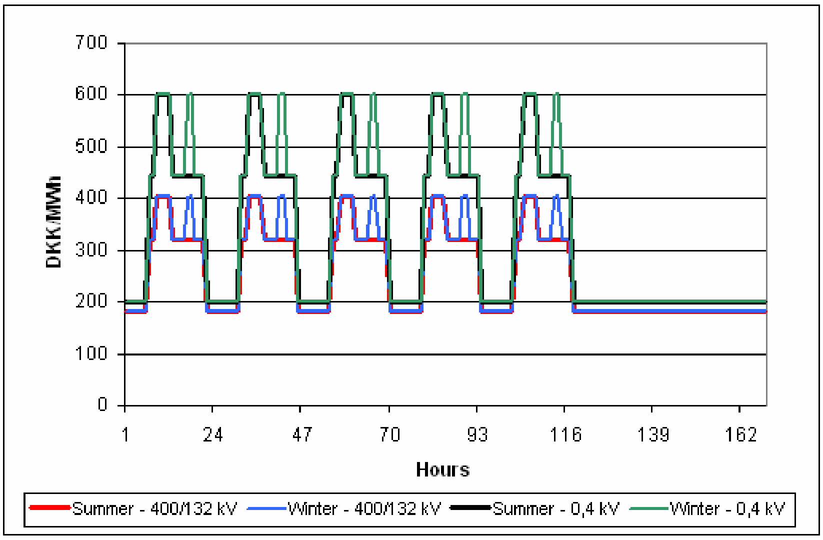

Figure 4 The three stage tariff during a week.

New legislation [1] states, however, that after January 1st 2005, all facilities with capacities larger than 10 MW must operate on market terms, which implies selling the electricity they produce on regular electricity markets, e.g. the Nordic electricity exchange, Nord Pool [10] where prices fluctuate considerably.

4 Combined Heat and Power Technologies

There are several key factors which define the local CHP plants. First there is the location: All electricity producing generators not located at one of the 19 central plant locations are by definition local. In a broad sense there are four categories of thermal CHP technologies, which are described in the following subsections.

4.1 Engine-driven Plants

Engine-driven plants are the most common form of local CHP. Basically a combustion engine powers an electricity generator to produce electricity. Heat recovery systems enable the use of heat from cooling water, lubricants and exhaust in the district heating network. Engines are generally fired by either natural gas or diesel. These plants account for about 85% of the number of installed plants and 45% of the electricity generation capacity in Denmark [3].

4.2 Steam Turbines

A steam turbine is basically a boiler which heats water, thus forming steam. This steam is pressurised over the length of a turbine, which in turn drives a generator. Traditionally exit steam has been cooled by an intake of seawater, but by replacing this with a district heating condenser, the heat is transferred to the district heating system. Steam turbines can either be back pressure units, which supply electricity and heat at a constant ratio, or extraction units. The latter gives added flexibility as it may vary from full back pressure mode to full condensing mode. Steam turbines with extraction capability combines the seawater condenser with the district heating condenser to get the desired ratio between electricity and heat. Approximately 6% of local CHP units in Denmark are steam turbines, but being generally large units they cover near 20% of installed electricity generation capacity [3].

4.3 Gas Turbines (single cycle)

A gas turbine can be coupled with a generator to generate electricity. Again heat can be recovered from exhaust gas. The advantage of gas turbines is that heat can be recovered without reducing the electricity production efficiency. However gas turbines have low regulatory ability, in that efficiency is drastically reduced when operating below nominal power [3].

4.4 Combined Cycle Technology

The combined cycle technology encompasses the combination of a gas turbine and a steam turbine. Instead of the steam turbine being supplied with steam from a boiler, it is driven by the high pressure exhaust from the gas turbine. Combined cycle facilities are usually of a rather large size. The combination of single cycle steam turbines and combined cycle facilities account for 6% of facilities in Denmark and an electricity generation capacity share of 35% [3].

4.5 Included Technologies

Three technologies were included in the simulations namely gas engines, single-cycle steam turbines and combined cycle facilities. Traditional steam turbines were omitted as there are only a few of these which use natural gas as primary fuel. They are however often used in conjunction with municipal waste furnaces, but these are due to technical and environmental considerations less likely to be put on market terms, at least not in the same form.

5 Modelling the Interconnected Systems

The degree of interdependence of the three systems increases with the gradual opening of the energy markets. Previously, local CHPs sold electricity at a fixed feed-in tariff, but from January 2005 this has changed for all local CHPs larger than 10 MW, and from January 2007 also for facilities larger than 5 MW [1]. The dependency of CHPs on the developments in the electricity market also resonates in the natural gas system. Local CHPs are major consumers of natural gas, and the future will demonstrate exactly how much this will influence the natural gas system, both in terms of daily operations and with regard to long-term security of supply.

In modelling the operation of individual plants first according to the feed-in tariff and old rules for natural gas [12] and secondly according to expectations of the development in market price and according to newer rules [13] and tariff structures of the natural gas system, it is possible to extract certain tendencies which follow from the liberalisation process, and specifically how this will affect the natural gas system.

5.1 Single Plant Model

The single plant model was created in connection with the project *Optimal drift af prioriterede anlæg* [11]. It is a linear programming (LP) model, which considers the situation from the point-of-view of a single gas-fired CHP plant. It is assumed that the plant consists of a CHP unit, which produces both electricity and heat; a boiler (also gas-fired), which only produces heat; and a heat storage facility.

The aim of the model is to minimise the production costs of the facility (including fuel costs), while selling electricity on the electricity spot market, and making sure that the local heat demand is met. The model takes into account the uncertainties inherent in the fact that spot prices are unknown at the time of bidding. Using historical data for days of the same type as the one for which the bid is made, the model creates a prognosis for the spot prices on the day of bidding and uses this in the optimisation.

In connection with the present paper, a second version of the model has been created that models the possibility of selling the electricity according to the three stage tariff. This model version is inherently deterministic, as the three stage tariff is well-known in advance of the production planning.

Both versions of the model are implemented using the GAMS modelling language [2].

5.2 Aggregated Model

Two types of simulations are run using the abovementioned model. One simulation is run for a number of relevant facility types using historical data with regard to the three stage tariff, heat demand, as well as rules and tariffs for natural gas transmission/distribution. This gives an indication of how historical load with respect to natural gas is likely to have been in the simulated time period, for the technology in question.

Using data describing the location, type, and capacity of gas-fired CHP facilities in Denmark results from simulations conducted with the model described in the previous section are aggregated multiplicatively to a number of network nodes matching the M/R stations of the natural gas transmission system. Hence an hourly load curve is generated for about 50 locations in Denmark.

This gas consumption profile is compared with realised total gas throughput on the M/R stations, and used to extract the portion of total delivered which was likely not used for heat and power generation in CHP facilities. This portion of gas is hereafter referred as residual consumption. It is assumed that from the year 2003 to the present there has been no change in residual consumption.

Hereafter, a second simulation is performed, this time with post-liberalisation cost structures and using the spot-market price for CHP electricity delivery. Results are once again aggregated according to the capacity index, added to the residual gas consumption, and compared with historic values. It is now possible to see whether the new structures with respect to cogeneration and natural gas supply serve to instigate increased or decreased total natural gas consumption. From this it is possible to evaluate the impact of the new liberalised structures may have for the natural gas transmission network.

6 Simulation Results

Three simulations have been performed using old rules and tariffs, and three using new rules and a model for calculating expected market price based on historical data. Each simulation consists of four one-week samples. All gas data is based on 2003 loads kindly supplied by Gastra A/S [9]. Results were generated for individual areas M/R station level. Thus station-by-station load variations can be observed.

For clarity and overview only national aggregated results are presented here. It is prudent to comment, however that the results vary from station to station depending on the presence of local CHP capacity adjacent to the individual stations, as would be expected. Thus while nationally aggregated results may not give rise to any major concerns, a thorough review of results station by station show that some places are more affected than others by the introduction of market terms.

Figure 5 - Figure 8 illustrate the historical natural gas consumption and the simulated consumption for local CHPs based on spot prices and on the three stage tariff.

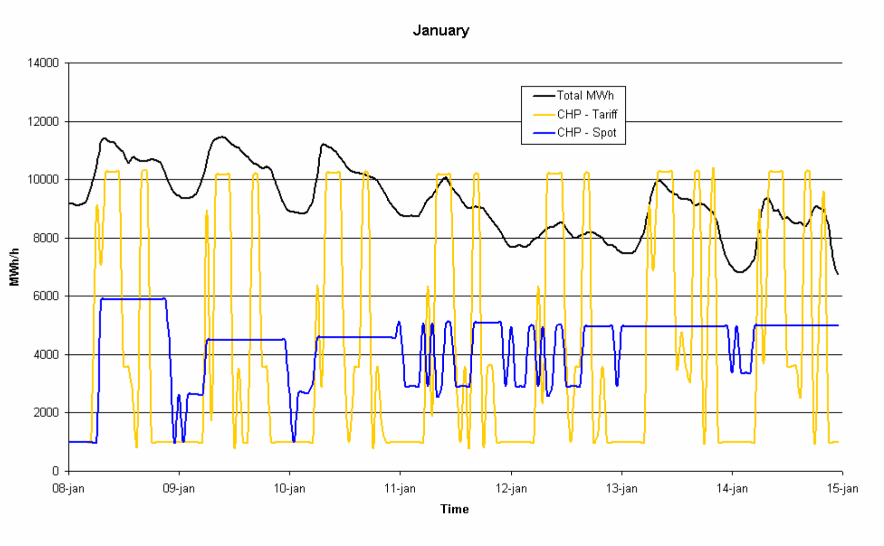

Figure 5 Historical and simulated consumption - January 2003.

In January (Figure 5) the results of the spot price simulation correspond nicely to the natural gas consumption. The dips in the graph are due to occasional expectations of low spot prices. The tariff simulation, however, is surprisingly volatile. This may be due to an overestimation of the available capacity. Also, the stability of the spot price consumption is due to the conservatism against the uncertainty inherent in the spot market. Interestingly enough, volatile and uncertain prices make stable consumption profiles.

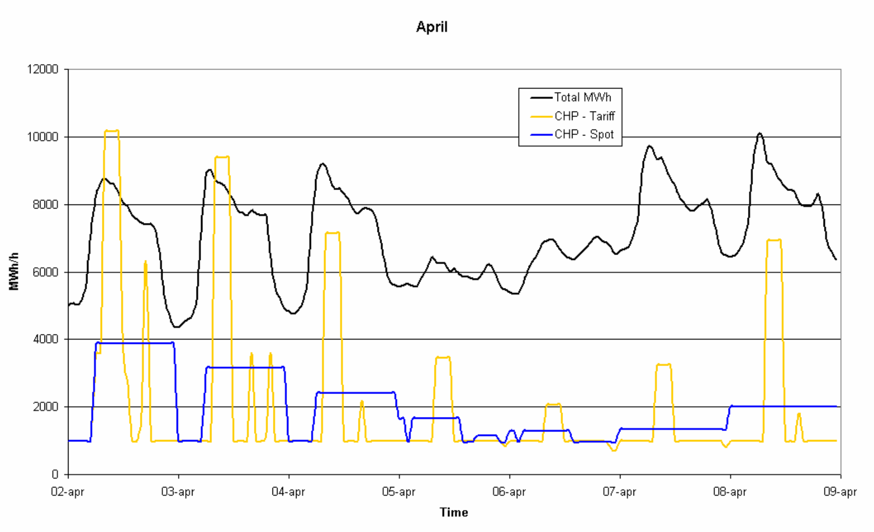

Figure 6 Historical and simulated consumption - April 2003.

For April (Figure 6), the tariff simulations are more reasonable with fewer extreme peaks in consumption. Note also that April is considered ‘summer’ and thus there is no evening peak in the tariff. The consequence is clearly seen when compared to January (Figure 5), as the evening consumption peak has decreased significantly. There is an increasing stability in the spot consumption which follows the total consumption.

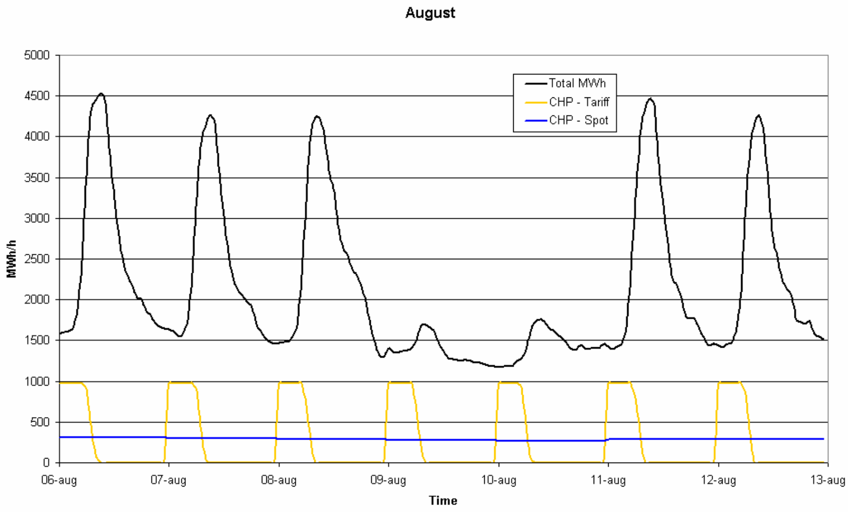

Figure 7 Historical and simulated consumption - August 2003.

In August (Figure 7) heat demand is low, thus in the tariff case consumption only occurs at peak prices, and in the spot price case (where prices are generally low) consumption is stabilised by the possibility of storing heat. It is interesting to note that there is a slight delay between the tariff consumption peaks and the historical outtake at the M/R station. This indicates an average delay in the distribution system of approximately 1½-2 hours. Note the large difference in scale compared to January (Figure 5), which may be explained by the large variations in heat demand from summer to winter.

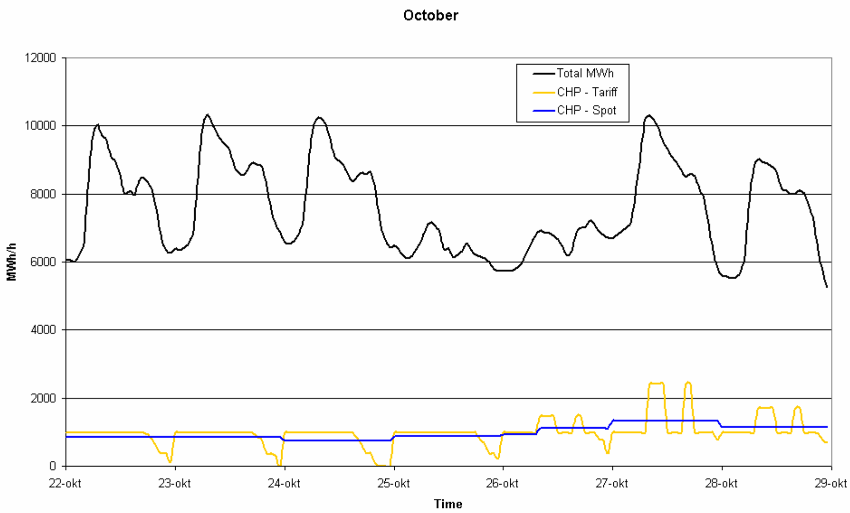

Figure 8 Historical and simulated consumption - October 2003.

The pattern in October (Figure 8) is likewise reasonable for both spot price and tariff simulations. The fact that the graphs are so level may be explained by the use of weekly capacity products in the natural gas transmission system. If, as is often the case, the local CHP purchases yearly transmission capacity products, the scale of these would be defined more by the high heat demand in winter, which would give a greater degree of freedom for the remaining year.

In general the amount of natural gas consumed is approximately identical for both the tariff and spot price cases. This indicates there is no notable change in the amount of electricity generated under the spot market setting compared to the tariff setting.

7 Discussion and Conclusion

It is clear from the simulation results that the production patterns of local CHPs will change as a result of the new conditions for their operation. When using cautious prediction of the spot prices the consequence is a stabilising effect on the consumption of natural gas. Unsurprisingly, the largest variations in consumption occurred in January as there was an opportunity of increased production due to the high heat demand.

The spot price model leads to greater stability in the consumption profile. This may be attributed to the use of short-term capacity products and caution in the face of uncertainty. The analysis does not support any existing concerns that the inclusion of local CHP to the spot market should serve to destabilise the security of the natural gas supply.

The simulations also indicate that there are no notable changes in electricity production when considering the spot market setting compared to the tariff setting.

There are issues of symmetry of both information and of response at work here. It is unlikely that all plants of similar types will operate exactly according to the same patterns. In reality every plant is different and this will force out some of the symmetry in the results. In addition there is the assumption that all local CPHs act unilaterally. In practice local CPHs pool their effort with regard to analysis and planning in responding to market developments. This increases symmetry of information but decreases symmetry of response by coordination between plants.

One unfortunate drawback of the applied approach is that there is a lack of feedback to the electricity market. Local CHPs are assumed to be price-takers, yet their relative market share and potential for symmetric response is likely to impact market movements. As electricity prices were fixed in the simulation according to historical values, the amount of electricity generated by local CHPs changed. Likewise it would have been interesting to see, how feedback to the natural gas market would have affected prices, and especially how this again would have altered the state of the natural gas supply system. Developing tools for this type of research, where the market influences the state of the supply system, which in turn affects the market development, is definitely an area for future research.

8 References

[1] *Aftale om Vindenergi og Decentral Kraftvarme* (Agreement about Wind Energy and Local Combined Heat and Power), Danish Energy Authority, http://www.ens.dk (2004).

[2] Brooke, A., D. Kendrick, A. Meeraus, R. Raman, *GAMS - A User's Guide*, http://www.gams.com.

[3] *Decentral kraftvarme i Danmark – Baggrundsrapport – Systemplan 2002*, Elkraft System (2002)

[4] Elkraft-System, TSO for the eastern Danish electricity system, http://www.elkraft-system.dk.

[5] Eltra, TSO for the western Danish electricity system, http://www.eltra.dk.

[6] Energinet.dk, TSO for the entire Danish electricity and natural gas system from January 2005, http://www.energinet.dk.

[7] Energistyrelsen (The Danish Energy Authority), http://www.ens.dk.

[8] *Forslag til lov om Energinet Danmark* (Proposal for law about Energinet Danmark), Danish Energy Authority, http://www.ens.dk (2004).

[9] Gastra, TSO for the Danish natural gas system, http://www.gastra.dk.

[10] Nord Pool, the Nordic electricity exchange, http://www.nordpool.no.

[11] *Optimal drift af prioriterede anlæg*, Eltra PSO project 4712 (2004)

[12] *Regler for gastransport og gaslagerydelser version 3.0*, Gastra (2003)

[13] *Regler for gastransport og gaslagerydelser version 4.0*, Gastra (2004)

[14] *Technology Data for Electricity and Heat Generating Plants (Draft, October 1, 2004)*, Danish Energy Authority, Elkraft-System, Eltra (2004)