The operation of small cogeneration plants and short-term storage for district heating and public electric power

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ABSTRACT

The introduction of small cogeneration plants together with the establishment of more complex rate structure for electricity and natural gas have contributed to a renewed interest in short-term heat storage. Studies have, therefore, been initiated in order to determine optimal operational strategies for the new plants and the stores subjected to the new conditions. The results of a simulation study that has been aimed at revealing some of the basic relationships are reported.

INTRODUCTION

In Denmark, cogeneration is responsible for covering a major fraction (27%) of the demand for space heating. Most of the cogeneration is concentrated in a small number of larger cities or towns. This, combined with a desire to increase the use of domestic fuels, such as straw, wood chips, sewage, garbage, manure, and even natural gas, has led to the establishment of a national 450 MW installed electric-power small cogeneration-plant program. The first phase of the program up to about 100 MW, is intended to be semi-experimental. The small number of units contemplated and possible unsuccessful experiments may make some of the plants unprofitable. However, the establishment of these plants, will contribute to the solution of a number of problems such as the balance of trade, the garbage disposal problem, the burning of straw in the fields, and the air pollution. It may even benefit the Danish industry by effectively supporting the development of these new plants through consumer-paid electricity.

A significant number of studies of small cogeneration plants have been undertaken [1] and a limited number of cogeneration plants has been established during the past 15 years. When operating these in the electric system with a two-step price schedule for the electricity and a constant fuel price or when only considering energy versus capital costs, short-term heat storage has turned out to be economically advantageous. It should be emphasized, in this connection, that the operation of a heat store by itself is an expense-generating activity and that it is only through its consequences for the operation of the associated cogeneration plants that the operation of a heat store will lead to economic gains or energy savings.

The new cogeneration plants will be introduced into systems with a three-step price schedule on the electricity and a natural-gas price that depends on the ratio
of heat and electricity generated according to a relatively simple formula, given later in this paper. The rest of this paper addresses only natural gas fired cogeneration plants. The most advantageous management strategy for these plants is not known and the optimum dimension of the associated heat stores, when subjected to these new rate structures is not known. But the picture certainly is expected to be significantly more complex than with the old conditions. The results of one study has recently been published that have had similar aims [2], but with emphasis on the optimum dimensions of the cogeneration plant. The present study will emphasize the size and operation of the associated store. The paper will first describe the old situation and the consequent operational philosophy. A simulation model is described and the results of simulation runs are presented and are discussed.

**THE PAST**

The first cogeneration plants were constructed before there was any established rate structure to account for the possible inconvenience that their existence imposed on the rest of the system. This inconvenience could occur in cases where a cogeneration plant, due to the heat demand, forced other power stations to close down during periods of low demand for electricity at night during winter.

By establishing a two-step price schedule it was possible to reduce this inconvenience, but it might also have reduced the cogeneration share of space heating. The typical two-step schedule specified a limited period, typically eight hours, during summer days, a longer period during fall and spring, and the entire twenty four hours during winters, during which peak-load price was being paid for electricity. During the off-peak periods, a lower price, barely covering the fuel costs was being paid. The optimal cogeneration plant operation was then eight hours during the summer time. With a heat store covering sixteen hours of summer heat demand (or eight hours of excess generating capacity over and above the lowest summer demand), it was possible to build the plant three times as large as what was needed to cover the summer heat demand. Thus, it was also possible to take advantage of the peak-load price during fall and spring.

The two-step price schedule thus represented an attempt to distribute the cost according to the required investment in installed generation capacity and the cost of fuel.

**SIMULATION MODEL**

The present study is using a simulation model that has been developed by the Danish Energy Agency. This model is used to simulate the generation of heat and electric power for a given cogeneration plant and store size.

The operation is governed by the weekly and annual variations in heat demand and subjected to weekly cyclical conditions of the state of the store. By running a large number of simulation studies it is possible to arrive at an optimal store dimension and associated operational strategy.

The model is based on a number of simplified descriptions, price relations and assumptions. These will now be presented.

The heat demand over a week is assumed constant. The variation of this demand over the year is shown in Figure 1.
The cost of the water tank is given by

\[ \text{Cost} = A_3 Q_L + A_4 \left( \frac{Q_L}{Q} \right) \]

where \( A_1, A_2, A_3 \) and \( A_4 \) are constants chosen to fit the experimental data and \( Q_L \) is the store size.

The unit price of the natural gas is given by

\[ \text{Unit Price} = A_5 Q_G + A_6 P \]

where the price for natural gas contributing to the generation of electric power is less than one quarter of that contributing to heating.

The investment costs are written off over a period of 20 years with an annuity of 9 percent.

The price for electric power follows a three-step schedule, depending on the hour of the week as shown in Figure 2.

The installation costs of the power plants follow relationships of the type

\[ \text{Cost} = A_1 + P \cdot A_2 \]

Figure 1. The Week Averaged Heat Demand through the Year.

Figure 2. Three-Step Price Schedule for Electricity. The Afternoon Peak Exists only During Winter Months (November-February).

Stochastic variations of demand have not been considered.
The operation of the store is subjected to two limiting conditions.

1. The store is operated cyclically and is empty at six o'clock on Monday morning.

2. The store has no overload capacity.

The simulation model is based on a simple step-by-step computation in time. The demand for a given geographical area is met by a combination of heat generated from the cogeneration plant and a gas-fired heating plant. The heat is primarily supplied by the cogeneration plant. Deficiencies are supplied by the heating plant. Start or stop costs have not been included. Simulations have been carried out for specified plant sizes. For each plant size, the store has been varied until the optimum size has been found.

RESULTS OF THE OPTIMIZATION STUDIES.

Store size

Typical curves for the marginal costs of the water tank and the marginal income from the sale of electricity for a given plant size and heat demand are shown in Figure 3. Patterns, generalizations or interpretations of the results have not been obvious. In order to ease the understanding of the results and their significance, the discussion below will start with some general considerations. On this background, the data may more easily be interpreted.

It has to be kept in mind that the curves of Figure 3 give the marginal costs. This means that for example, for \( C_m = 0.24 \) a small store will not be profitable. Even though the marginal benefits exceed the marginal costs over a significant range of store sizes, the total cost will not be recouped. The reason for this is that the electric power generation is too small to offset the increased cost. However, for \( C_m = 0.94 \), the marginal benefits exceed the marginal cost for the whole range values up to very large store sizes. On the one hand, this gives a significant return on the investment. On the other hand, this return could be wiped out by fairly small relative shifts in prices of fuel, investments or electricity for store sizes above 60 MWh.

![Figure 3. Marginal Cost and Marginal Income Associated with the Establishment of Warm-Water Storage in a District Heating System. Annual Heat Demand 440 TJ, Cogeneration Heat Capacity 10.6 MJ/s.](image-url)
Past experience has shown that the heat demand during the low-load summer weeks \( Q_{\text{DMin}} \) weigh very heavily in the present context. The energy content of the store is, therefore, expressed by the hours \( r \) that it takes to charge it by the summer excess heat generating capacity \( \dot{Q}_G - \dot{Q}_{\text{DMin}} \).

Analysis of the detailed output data indicate that it might be helpful to consider two different store dimensions.

First, there is the day store. For small cogeneration outputs, the main objective of the daily storage cycle would be to generate as much heat and associated electricity as possible during the peak-load and medium-load periods. For cogeneration plants where \( \dot{Q}_G \) is smaller than \( \dot{Q}_{\text{DMin}} \), no store is required. However when \( \dot{Q}_G \) increases beyond \( \dot{Q}_{\text{DMin}} \), a store of a size corresponding to 14.5 hours of excess heat-generating capacity is required as shown by the horizontal line in Figure 4.

When the heat generating capacity of the plant exceeds what is needed to generate the daily heat demand during the 14.5 hours, the storage size remains constant, measured in energy units. But since the generating capacity increases, its size decreases when expressed by the number of hours required to charge it, as shown by the falling line in Figure 4.

Second, there is the week store. The main objective of the weekly storage cycle is to provide heat during the weekend. When the heat generating capacity is increased beyond what is required to meet the daily demand, the excess heat may be accumulated over the five weekdays to be used during the weekend. The store required to function both in the daily and in the weekly cycles is shown by the rising curve in Figure 4. The weekly storage cycle is
only of interest when the workday require-
ments already have been met, that is, when
the cogeneration plant exceeds a certain
size, as shown in the figure.
This means that, beyond a cogeneration
plant size of \( \dot{Q} = 4 \dot{Q}_{\text{DMin}} \), two alternative
store sizes may exist. One, small, is di-
mensioned for daily storage and one, large,
is dimensioned for daily and weekly
storage.

The exact shape of the curves in Figure 3
can not be derived by such simple con-
siderations, but has to be derived from
simulation studies.

The optimal store dimensions for \( C_m = 0.47 \)
derived by simulations of the type that
have lead to data of the type shown in
Figure 3 have been included in Figure 4,
which, in effect are the main results of
the present simulation studies. It is seen
that the simulation results are reasonably
close to the general curves that have been
derived by qualitative arguments, thus
confirming these.

The divergence from these curves may be
caused by the simplifying arguments that
either start from summer medium-load and
peak-load periods or from winter peak-load
periods. The real situation, reflected in
the complete load-duration curve, is more
complex, however, and the results of the
simulations will also reflect the influence
of situations during the year that lie
between these two extreme situations.

One complicating factor in applying the
results is, as already mentioned, the fact
that beyond \( \dot{Q}_C = 4 \dot{Q}_{\text{DMin}} \) there are actually
two alternatives:
one small day store
or
a quite large day-and-week store.
The arguments leading to these two alterna-
tives were mainly based on energy-systems
considerations rather than on economics.
There should be no doubt that daily storage
is more interesting economically than
weekly storage. But the marginal costs of
establishing a warm water tank decrease
considerably with size, and beyond a
certain size the economic gains achieved by
exploiting this weekly cycle may be
considerable.
However, the required store size may be 5
to 10 times as large as what is required
for daily storage. The problem may then be
environmental rather than economic. A water
tank for day storage is large compared to
the corresponding cogeneration plant. A
water tank for weekend storage would have
overwhelming dimensions, and might not be
acceptable in a small community or residen-
tial area.

It also has to be kept in mind that the
cost of a heat store and also the possible
economic gains are about one order of
magnitude lower than the cost of the
corresponding cogeneration plant and that
the potential gains may be wiped out by
reasonably modest relative shifts in the
prices of fuel, electricity, and water
tanks.

The above discussion has only addressed the
data for \( C_m = 0.47 \). As already stated, the
data for \( C_m = 0.24 \) are fairly uninte-
resting for the modest sizes studied in the
present paper, as they show that electric
power generation is too small to really
matter, and the investment in a storage
tank is not very economic.
The data for \( C_m = 0.94 \) essentially show
that in this case the electric power
generation is very important. This mani-
fests itself by the fact that week storage
becomes interesting even at fairly small
values of cogeneration heat. This, in fact
means, that it is economically attractive
to generate heat for weekend storage even during medium-load periods (as opposed to day storage).

Operational Philosophy
With a two-step price schedule, the operational philosophy was reasonably simple. With the new three-step schedule, the operation is only slightly more complex. The goal is first to shift as much of the electric power generation as possible to peak-load periods. If there is still uncompensated heat demand this production should be shifted to medium-load periods. The price of electricity in medium-load periods is still high, while the price in low-load periods barely compensates for the cost of fuel. Heat for week storage may be generated during medium-load periods ($C_m$ is high) or only during peak load periods ($C_m$ is moderate) (or not at all $C_m$ is low).

SUMMARY AND CONCLUSIONS

A theoretical investigation of the economics of cogeneration supplemented by warm-water storage subjected to a three-step price schedule for electricity, has been carried out. Some general guidelines may be derived, but no simple design rules, such as the ones described for the old situation with a two-step schedule, seem to govern the design of such plants when subjected to the new conditions. Full-fledged simulations will have to be carried out in order to arrive at sufficiently accurate optimal store dimensions and operational strategy. The results from simulation studies, that give the store as a function of cogeneration plant size relative to the total heat demand in the geographical region supplied by the plant are shown in Figure 4.

References

1. Studies of small Decentralized Cogeneration Plants undertaken by various power companies, gas companies, communities, and research organizations. In Danish. 1975-89.