Available online at www.sciencedirect.com
SCIENCE DIRECT
Applied Energy 78 (2004) 1–18
APPLIED ENERGY
www.elsevier.com/locate/apenergy

Calculating the marginal costs of a district-heating utility

Jörgen Sjödin*, Dag Henning

Linköping Institute of Technology, Department of Mechanical Engineering, Division of Energy Systems, SE-581 83 Linköping, Sweden

Received 26 March 2003; received in revised form 22 April 2003; accepted 26 April 2003

Abstract

District heating plays an important role in the Swedish heat-market. At the same time, the price of district heating varies considerably among different district-heating utilities. A case study is performed here in which a Swedish utility is analysed using three different methods for calculating the marginal costs of heat supply: a manual spreadsheet method, an optimising linear-programming model, and a least-cost dispatch simulation model. Calculated marginal-costs, obtained with the three methods, turn out to be similar. The calculated marginal-costs are also compared to the actual heat tariff in use by the utility. Using prices based on marginal costs should be able to bring about an efficient resource-allocation. It is found that the fixed rate the utility uses today should be replaced by a time-of-use rate, which would give a more accurate signal for customers to change their heat consumptions.

Keywords: District heating; Marginal costs; Modelling; Combined heat and power

1. Introduction

Distribution of district heating is a natural monopoly and there is a possibility for monopoly behaviour in tariff pricing and enrolling of customers. With the liberalisation of the Swedish electricity market in 1996, old regulations stating cost pricing and an equal treatment of customers were recalled from the Swedish district-heating sector [1]. Now there is a question of how to price district heating in the liberalised energy market.

* Corresponding author. Tel.: +46-13-104754; fax: +46-13-281788.
E-mail address: jorsj@ikp.liu.se (J. Sjödin).

0306-2619/03/$ - see front matter
doi:10.1016/S0306-2619(03)00120-X

District heating (DH) can be found in about 80% of the Swedish municipalities and has a large share of the heat market. However, there is a limited occurrence of combined heat-and-power (CHP) generation. Whereas more than 43 TWh of DH were supplied to end-use customers in 1999, no more than 4.5 TWh of electricity were generated via the CHP mode. The EU average of the DH fraction produced in CHP plants was in 1999 higher than 60%. The total Swedish residential heat market has been estimated to be 94 TWh, while the national electricity consumption in 1999 totalled 143 TWh [2–5].

Average revenues from district heating vary among Swedish utilities between approximately 300 and 600 SEK[1] per sold MWh, excluding the 25% value-added tax, VAT [6]. Prices can differ due to the number of customers, heat density, age of the district-heating system, loan circumstances, profit expectations, cost-effective use of energy resources, and cross-subsidisation. Small DH utilities having CHP generation can be regarded as price takers of electricity, while being price setters for district heating. They operate on two different markets and face the issue of allocating joint costs and revenues from CHP generation.

The aim of this study is to demonstrate three models for calculating a utility's marginal costs for district heating. The structure of the paper is as follows. First, marginal costs are briefly discussed. Second, some general features of cost and revenue allocation in CHP systems are reviewed. In the third section, a case study is performed. A utility's technical energy-system is analysed using three different methods for calculating marginal costs. One is a manual spreadsheet method, another method involves an optimising linear-programming framework, and the third method uses is a least-cost dispatch simulation model. In a closing discussion, the resulting marginal costs are compared to the utility's actual heat-tariff.

2. Costs and pricing

A basic presupposition here is that optimal prices from a societal point of view should equal short-range marginal costs (SRMC) of DH generation. These prices reflect the scarcity of resources in society, and are the best means for optimal resource allocation. However, such prices do not guarantee full cost coverage for the producer. Consequently, a fixed charge, besides variable prices, can be justified. With monopoly, the producer can use his market power when setting tariffs. Monopoly pricing, when the producer tries to maximise his revenues, tends to keep production down and prices high. Rather, prices can be set to reflect marginal costs, and a fixed charge can be set to cover investment costs. More elaborated discussions on utility pricing, and SRMC versus long-range marginal costs (LRMC), can be found in e.g. [7–9].

Alternate cost pricing is a pricing policy in common practice. The heat price is set just below the price customers would pay for an alternative heating technology. In Sweden, common alternatives to district heating are electric boilers and oil boilers.

[1] One Swedish Krona (SEK) equalled 0.110 Euro in March 2003.

With alternate cost pricing, a utility may earn larger revenues from their DH operation. The price of oil, including taxes, renders a typical heat price around 700 SEK/MWh heat for dwellings. Due to low electricity prices experienced during the past two decades, electric heating is common in Sweden. Such heating alternatives have until recently rendered a price at approximately the same level as oil.

In the subsequent case study, calculations of marginal costs are made with different approaches. One approach is to use a linear-programming (LP) model. In linear programming, the resulting shadow prices are the values of the dual variables, representing the effects of small changes on the right-hand side coefficients (e.g. for demand) of a constraint [10]. Shadow prices represent the marginal costs of a unit increase in energy demand and reflect a price that may be uniformly charged to all consumers [11]. The MODEST LP model, used in this case study, has previously been used to determine shadow prices for heat generation. In studies by Nilsson and Söderström [12], and Andersson [13], shadow prices were interpreted and used as a theoretical tariff. Wene [14] has also affirmed that shadow prices obtained with the Markal LP model should provide a basis for the district-heating rate. In the following, we presume that SRMC or shadow prices are suitable to form the basis for the pricing of DH.

3. CHP and allocation of joint costs

Despite the low penetration of combined heat-and-power generation in Sweden, CHP is recognised as a promising future technology. Large investments have already been made in DH grids and there is a large biofuel potential yet to be utilised for combined generation. Furthermore, Sweden has a simultaneous need for electricity and heat. When the outdoor temperature turns low, the electricity demand increases because of all the electric heating. At the same time, the demand for district heating increases. CHP could play an important role when Swedish nuclear-power is phased out.

When district heating is produced with heat-only boilers, the calculation of marginal costs is relatively straightforward. In DH systems with CHP generation, the calculation of marginal costs is more complex. In order for CHP generation to be profitable, the market value of generated electricity and heat must exceed the joint generation costs of the CHP plant. The joint cost function of a CHP plant can be formulated as

$$\frac{\text{Fuel Costs}}{\eta} = \frac{\text{Heat Value} + \alpha \ (\text{Electricity Value})}{1 + \alpha} \tag{1}$$

where η denotes the total efficiency, and α the electricity-to-heat ratio. The joint CHP cost function can be interpreted as the zero-profit frontier. Below this line, costs are not fully covered. Only when the value of heat and electricity exceeds the production cost, production will be profitable. Total costs of combined generation can be split in an infinite number of ways on the isocost line [Eq. (1)]. Allocation of joint costs can be made according to various principles. The following outline of methods of allocation is derived from Verbruggen [15], Fredriksen and Werner [16], Schlamadinger et al. [17], Mayerhofer et al. [18], and Lucas [19].

In a residual approach, the value of generated electricity can be set to the electricity market price or the generation cost in a *standard reference power plant*. Total CHP costs are subtracted by this electricity value in order to obtain the heat costs. In this case, the heat cost becomes relatively low. This method of allocation is therefore probably proposed by a utility's district-heating division. Electricity is considered somewhat of a by-product and all benefits of simultaneous generation are assigned to heat.

As an opposite principle of allocation, the heat value can be set to a heat-market price or a *standard heat-only boiler* production cost. Total CHP costs are subtracted with this heat value in order to obtain a cost for electricity. As a general result, the electricity cost becomes relatively low. Since heat is considered somewhat of a by-product and all benefits are assigned to electricity, this method of allocation probably is proposed by the utility's power division.

Another method is simply to allocate costs in proportion to the amounts of generated *energy*, i.e. in relation to the electricity-to-heat ratio. Thus, it is assumed that electricity and heat are produced with the same efficiency. Consequently, this method usually attributes an efficiency of CHP electricity generation of close to 100% since the total efficiency (heat and electricity) generally is close to 100%. As the electricity-to-heat ratio often is low, usually somewhere between 0.30 and 0.60, this method will attribute a larger portion of the total costs to heat production. Incidentally, this is the way CHP generation is viewed by the Swedish system for energy taxation, where different tax levels apply for electricity and heat production. The taxation of CHP generation indicates that fuel costs are to be split proportionally between the fuel used for heat and electricity production. Heat is heavier taxed than electricity at the stage of production and heat may thus be viewed as more costly.

Allocation can also be made in proportion to the *exergy* of the generated energy forms. The exergy content of heat may be calculated by using the Carnot factor. As a result, this method will normally attribute a relatively large portion of the costs to electricity generation.

Exergy loss in a CHP plant can be defined as the difference between the electricity that is produced by cogeneration and the electricity that could be generated with all the supplied fuel in a condensing plant. The difference corresponds to lost electricity in cogeneration, and its value is attributed to the cost of heat production. The remaining part of the total production cost is attributed to the produced electricity.

Yet another combined method compares CHP production with the *ratio of separate standard power and heat plant's stand-alone efficiencies*. The allocation between electricity and heat costs in a CHP plant is thus made in accordance with the ratio between the necessary fuel amounts for generation of the electricity and heat in separate plants.

We argue, in accordance with Verbruggen [15], that allocation according to the first residual method (standard reference power plant), and where electricity is considered somewhat of a by-product, is fair and reasonable. There is a district heating demand that needs to be supplied. With combined heat-and-power generation, the heat is considered as the main product. Electricity can be sold and purchased on the deregulated market. Without CHP generation, the DH demand needs to be supplied through heat-only boilers or heat pumps. Electricity from CHP generation can be valued in accordance with the electricity market. In the case study below, we use a set of assumed spot-market prices on electricity to assess the heat costs of CHP generation.

4. Case study

The municipal district energy utility Tekniska Verken in Linköping AB is located in Linköping some 200 km south-west of Stockholm. Having 140 000 inhabitants, it is the fifth largest city in Sweden. The district-energy utility is responsible for district heating generation as well as local electricity distribution and is wholly owned and operated by the municipality. The district-energy business annually produces and distributes some 1200 GWh of heat and a small amount of steam. The maximum heat-demand is usually somewhere between 360 and 430 MW depending on the outdoor temperature in winter. The utility has one of Sweden's lowest tariffs for district heating with a variable cost of 265 SEK/MWh in 2002 (excluding 25% VAT), for all non-industrial customers all year round and regardless of capacity requirement. In addition, there is an annual fixed charge, which is proportional to the subscribed capacity.

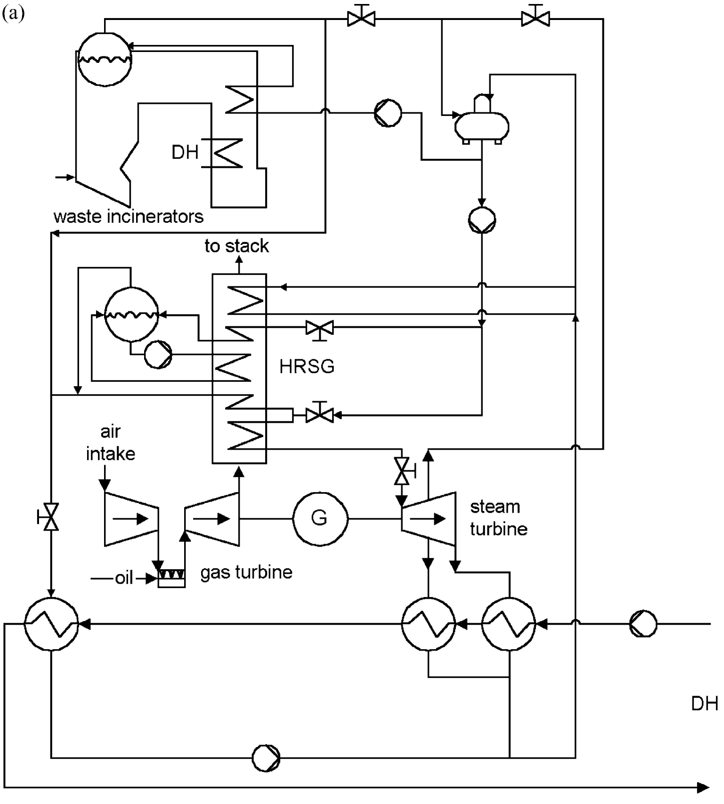
Coupled with the district-heating production, around 340 GWh of electricity are annually generated in three thermal-power plants. Such a share of thermal (CHP) electricity generation in proportion to generated district heating is relatively high by current Swedish standards. The utility's energy system is technically complex and has a high degree of fuel flexibility.

The *Gärstad plant* consists of three waste-incineration boilers coupled with a steam turbine through a gas-turbine's heat-recovery steam generator (Fig. 1a). Light fuel-oil is used for the gas turbine with a shaft output of 25 MW. The plant can be operated in CHP mode with the turbines in operation but usually the waste incineration boilers produce district heating only. With flue-gas condensing, the maximum output of the plant is about 100 MW heat.

The *KVV CHP plant* has three boilers (Fig. 1b). The *coal* boiler is fuelled with a mixture of coal, rubber and wood. This boiler is equipped with an economizer. The *biofuel* boiler is fuelled with a mixture of wood and plastics. It is equipped with an economizer and flue-gas condensation. The *oil* boiler can use either heating oil or animal fat. Maximum heat-generation capacity at the KVV plant is 240 MW. With a certain amount of condensing extraction generation, the total output can reach 86 MW electricity and 180 MW heat.

The *Tornby plant* consists of two diesel-engines able to produce 7 MW electricity each (Fig 1c). At the same site, there are two heat-only oil boilers and an electric boiler. A main purpose with this plant is to supply nearby located industries with process steam. However, it can also be used to supply the district-heating system with hot water.

(a)



(b)

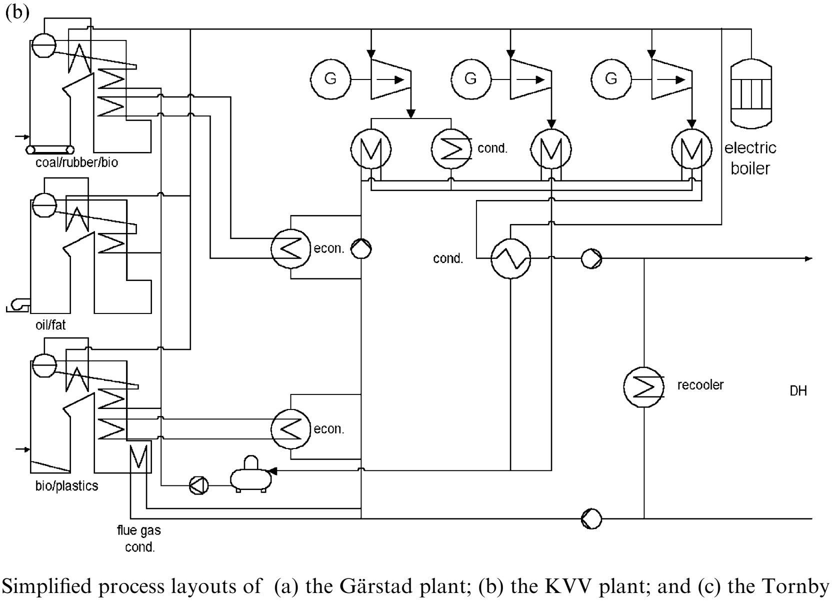


Fig. 1. Simplified process layouts of (a) the Gärstad plant; (b) the KVV plant; and (c) the Tornby plant.

(c)

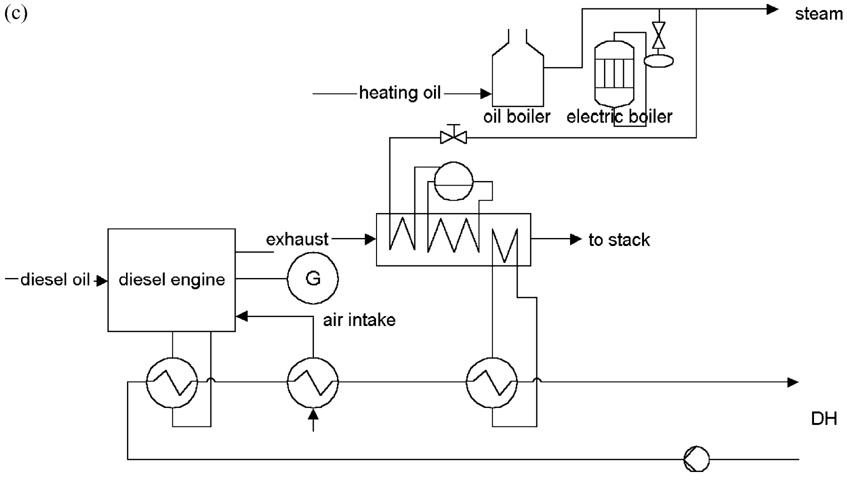


Fig. 1 (*continued*).

Furthermore, six heat-only oil boilers, mainly at the outskirts of the city, have a total installed capacity of 157 MW. These are primarily used during cold winter days and for back-up purposes. For a similar purpose, a 25 MW electric boiler is installed close to the KVV plant (Fig. 1b). Depending on the precipitation, some 45–85 GWh hydropower is annually generated in the utility's hydropower plants. One wind-power plant makes a minor contribution. As a result, the amount of self-generated electricity totals about 420 GWh annually. However, the present customer demand in the city is close to 2 TWh, resulting in rather extensive supplementary purchases in the electricity market.

Actual monthly production of heat is shown in Fig. 2. The base load is supplied by waste incineration at the Gärstad plant. Instead of paying a tax on landfill, the incineration yields revenues, which makes it advantageous as base-load production. The three boilers at the KVV plant also supply significant amounts of heat. Primarily, wood and plastics are used as they have low costs. Secondly, the boiler fuelled with coal, rubber, and a smaller portion of wood is committed. In the third place, the oil and fat boiler is in operation. Electric boilers and the oil-fired heat-only boilers are used to balance demand during winter. In recent years, the gas turbine at Gärstad and the Tornby diesel-engines have been scarcely used.

4.1. Manual calculations

A simple manual method is to calculate variable costs for generating heat directly from the Swedish system for energy taxation. Presently, on fuels used for electricity generation, there is only a sulphur tax applied. For fuels producing heat in heat-only plants and heat in CHP plants, there is both an energy tax and a carbon tax. In the latter case there is a 50% discount on the energy tax.

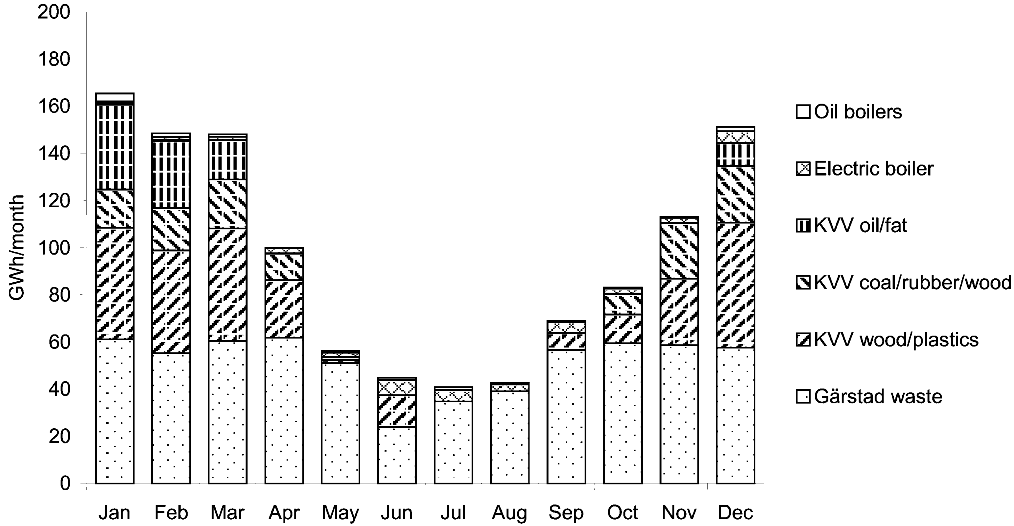


Fig. 2. Actual monthly production of district heating at the utility in 2000.

For heat-only plants, the variable cost (VC) can be expressed as:

$$\mathrm{VC}_{\text{boiler}} = \frac{\text{Fuel price} + \text{Sulphur tax} + \text{Carbon tax} + \text{Energy tax}}{\eta} \tag{2}$$

In combined generation, the value of produced heat and electricity will influence the other product's variable cost. The variable cost for heat may therefore be calculated as:

$$\begin{aligned}\mathrm{VC}_{\text{CHP-heat}} = {} & \frac{\text{Fuel price} + \text{Sulphur tax} + \text{Carbon tax} + \frac{1}{2}\text{Energy tax}}{\eta} \\ & + \alpha \cdot \left(\frac{\text{Fuel price} + \text{Sulphur tax}}{\eta}\right) - \alpha \cdot \left(\text{Price of electricity}\right)\end{aligned} \tag{3}$$

The first term in Eq. (3) captures the fuel costs of producing heat, and the second term the costs for the fuel producing the associated electricity. In the last term, credit is given for the value of generated electricity. Consequently, the expression resembles the first residual method outlined above.

The utility uses a detailed manual spreadsheet method for calculating marginal costs that follows Eqs. (2)–(3). During each month, a certain boiler is assumed to provide the majority of the marginal heat to the district heating system (Table 1). But during a certain fraction of the month, two other boilers provide the marginal heat and an average marginal cost for each month is calculated. January and June may serve as examples. In January, the major supply of marginal heat is expected to come from the oil boiler at the KVV CHP plant. The biofuel boiler at the KVV CHP plant is supposed to be the marginal source of heat during 8% of the time, while the heat-only oil boilers are assumed to supply marginal heat during 7% of the time. In June, when waste incineration is shutdown for maintenance, the biofuel boiler at the KVV CHP plant is expected to supply marginal heat throughout the month.

4.2. Modelling with the MODEST model

Complementary to manual methods applying historic or presumed production of district heating as means for calculating marginal costs, computer models can be used to simulate production. Advantages with such tools may include a more detailed time division and an increased ability to analyse the influence of changes in input parameters. MODEST is a model framework developed for simulation of municipal and national energy systems. The model has been described in detail by Henning [20,21]. Being similar to the MARKAL model, it is a linear-programming optimisation tool. The model has been used frequently for studies of Swedish energy systems. The name is short for Model for Optimisation of Dynamic Energy Systems with Time-dependent components and boundary conditions.

The utility has been analysed rather thoroughly with the MODEST framework by several analysts. Some of the data used in this study have emerged from computa-

Table 1
Time-shares of production considered being on the margin in the manual method of calculating marginal costs

Month	Period	Time share (%)	Type of marginal heat-generation	Month	Period	Time share (%)	Type of marginal heat-generation
January	Period 1	7	Heat-only oil boiler	July	Period 1	7	Electric heating
	Period 2	85	CHP oil		Period 2	85	Waste incineration
	Period 3	8	CHP woodchips		Period 3	8	Waste incineration
February	Period 1	7	Heat-only oil boiler	August	Period 1	7	CHP coal
	Period 2	85	CHP oil		Period 2	85	CHP rubber/coal
	Period 3	8	CHP oil		Period 3	8	Waste incineration
March	Period 1	7	CHP oil	September	Period 1	7	CHP woodchips
	Period 2	85	CHP oil		Period 2	85	CHP woodchips
	Period 3	8	CHP woodchips		Period 3	8	Waste incineration
April	Period 1	7	CHP oil	October	Period 1	7	CHP oil
	Period 2	85	CHP woodchips		Period 2	85	CHP woodchips
	Period 3	8	CHP woodchips		Period 3	8	CHP woodchips
May	Period 1	7	CHP woodchips	November	Period 1	7	CHP oil
	Period 2	85	CHP woodchips		Period 2	85	CHP oil
	Period 3	8	Waste incineration		Period 3	8	CHP woodchips
June	Period 1	7	CHP woodchips	December	Period 1	7	Heat-only oil boiler
	Period 2	85	CHP woodchips		Period 2	85	CHP oil
	Period 3	8	CHP woodchips		Period 3	8	CHP woodchips

tions made with Modest by the utility. In brief, the objective of the model is to minimise costs of meeting a demand for district heating.

Modest comprises a matrix-generator program for the input data of the energy system. Input can be made through a graphical user interface or directly in the Pascal programming code. Modest then generates an input (MPS) file for the optimisation software (Cplex™) where the actual optimisation is carried through. A result-transformer program extracts information from the optimisation output file and compiles tables for further handling in e.g. Microsoft Excel™.

The real continuous load curve is here represented in Modest by a discrete load curve with 88 periods. Costs that are considered in the model include all fuel costs, taxes, and operating and maintenance costs. The result of the analysis includes when plants should be in operation and at what output, which fuels that should be used, total costs, and shadow prices.

For periods where alternative operating schemes are equally beneficial, no shadow prices are obtained. For some time-periods during summer, shadow prices are estimated manually by interpolating the values from adjacent periods.

Fig. 3 shows in a simplified way how the utility is modelled in Modest. Fuels used for heating, cogenerated heat, and electric-power generation, are subject to different Swedish taxes. Therefore, one real fuel may be represented by several "model" fuels. Fuel flows have costs, including taxes, and an efficiency of the subsequent conversion technology. Conversion technologies usually have capacity constraints and, where applicable, an electricity-to-heat ratio.

Optimal monthly production of heat calculated with the Modest model is shown in Fig. 4. Comparing the results with actual production in 2000 (Fig. 2) shows that the operation is similar.

4.3. Modelling with the Martes model

The Martes model is a computer-based simulation tool designed for the analysis of district-heating production [22,23]. Martes is a merit-order dispatch model that enables economic and emissions analyses. The model is based on load curves representing demands for heat and steam. The load curves consist of 730 time-periods (two periods each day during the year) or, alternatively, 8760 time-periods (hours) per year. In the first alternative, one 16-h period represents daytime and one eight-hour period represents night. Plant operation is here simulated for each day and night during a year. Units are committed according to their variable costs, which are calculated from Eqs. (2)–(3). Deviations from the basic least-cost dispatch may be induced by giving units a certain priority overruling the merit-order. Other features in Martes enables, e.g., electricity generation in condensing mode, load-dependent electricity-to-heat ratios, capacity ratios between different units, and minimum capacity adjustment. Each unit may have a certain minimum capacity. If the simulation calls for capacity, which is less than the minimum capacity of the consecutive unit, this unit cannot be taken into operation. However, with minimum capacity adjustment, the model calculates if it is more profitable to reduce the output of the preceding unit in order to enable the subsequent unit to run at minimum capacity.

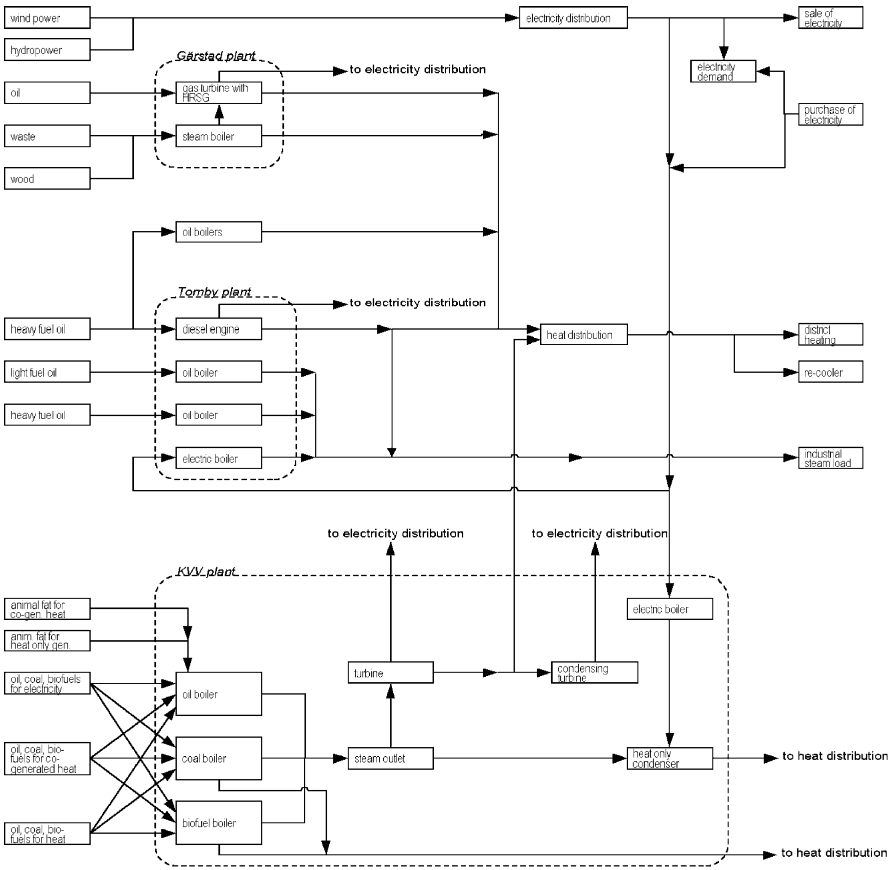


Fig. 3. Simplified layout of the MODEST model of the utility. Biofuels consists of wood, rubber, and plastics.

Martes can be used for analysing the profitability of investments and budgeting. Furthermore, emissions, fuel mixes and fuel stocks, alternative taxes and environmental fees, as well as the profitability of connecting several district-heating systems can be analysed, including the calculation of marginal costs. Martes can thus be used in much the same way as the MODEST model.

The utility has been implemented in Martes as illustrated in Fig. 5 [22]. Being able to automatically handle the special taxation of combined generation, the model includes fewer fuels than the MODEST model. Some of the conversion units are adapted or even fictitious in order to depict the utility's many options for plant operations. A cogeneration-plant's boiler, turbine, and generator are implemented as one unit. Two different fuels with different conversion efficiencies may be coupled to such a unit. The algorithm chooses the cheapest fuel to use for heat and electricity generation, respectively. However, the model cannot handle four different fuels, such as coal, oil, wood, and rubber in the utility's KVV cogeneration plant. Neither can

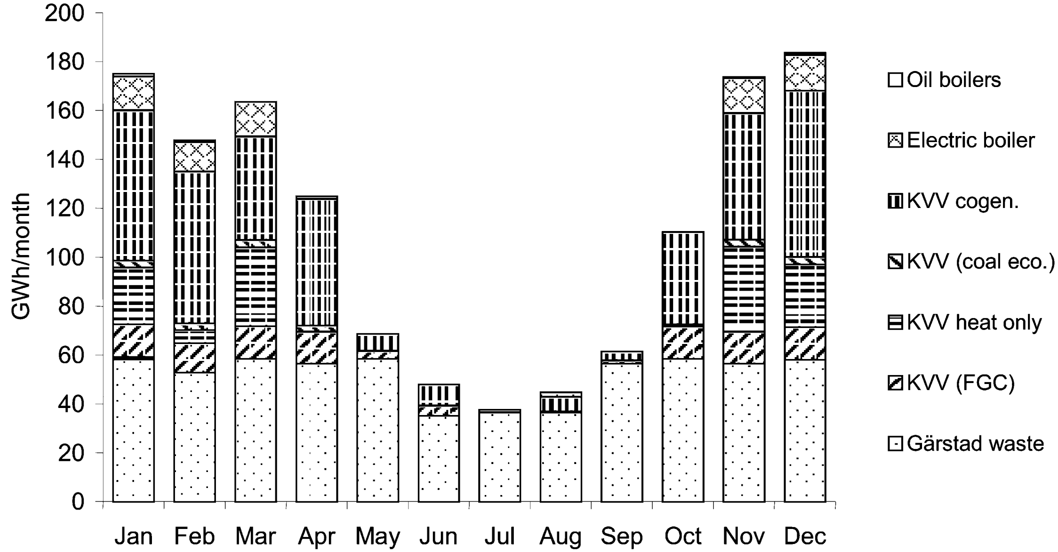


Fig. 4. Monthly district-heating production according to MODEST model simulation (eco = economizer; FGC = flue-gas condensation).

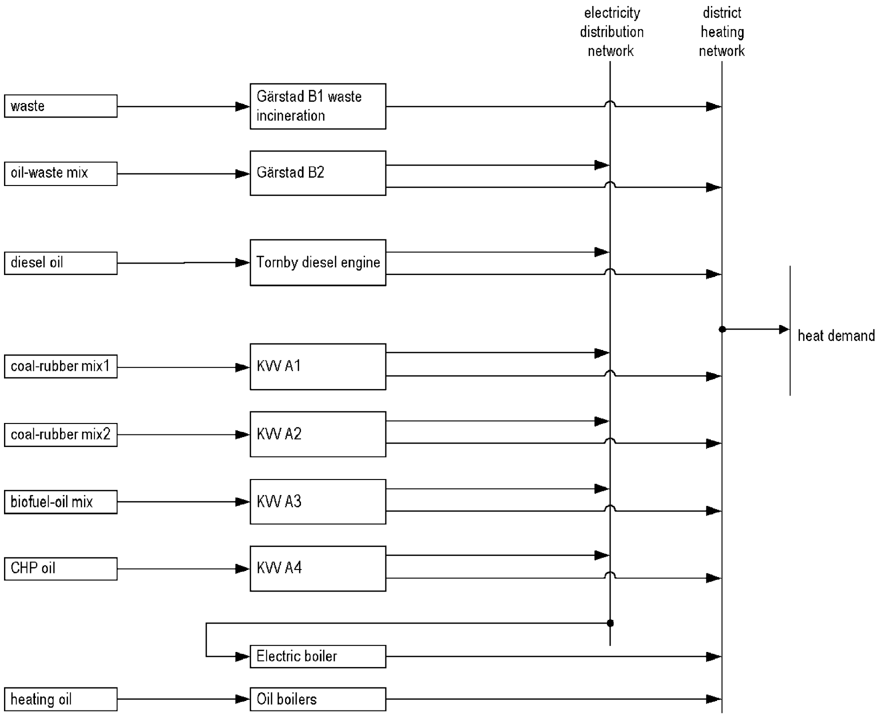


Fig. 5. Martes model of the utility. *A1* includes the KVV boiler using rubber and coal. *A2* enables further combustion of rubber and coal in CHP and condensing mode. *A3* is fuelled with wood, plastics, and oil, and *A4* is fuelled with oil having a reduced CHP tax. *B1* represents heat-only waste incineration at the Gärstad plant. *B2* represents Gärstad using waste-incineration boilers and the gas turbine with heat-recovery steam generator.

Martes handle different capacity constraints applying to different fuels for the same unit. Therefore, the KVV cogeneration plant is split into four units. A certain share of rubber is supposed to be used. For that reason, the first cogeneration unit (A1) includes the boiler using the rubber–coal fuel mix. Another unit (A2) can be operated in condensing mode to enable further combustion of rubber and coal. These two units' collective output is constrained. A third unit (A3) is fuelled with biomass, plastics and oil. This oil is assigned to electricity generation. A fourth and complementary unit (A4) is fuelled with oil, which is taxed as used for CHP generation.

The Gärstad plant is implemented using two fictitious units. The first unit (B1) represents heat only waste incineration, while the other unit (B2) represents Gärstad operating in cogeneration mode, i.e. using both waste incineration and a gas turbine with a heat-recovery steam generator. In the latter case, the unit is fuelled with "a mixture" of waste and oil. By using a Boolean operator, only one of the two Gärstad units is able to operate within the same time-period.

Allocation of costs for combined heat-and-power generation is computed according to Eq. (2). The value of generated electricity is set exogenously corresponding to the same estimated spot market prices as in the MODEST simulations. The marginal

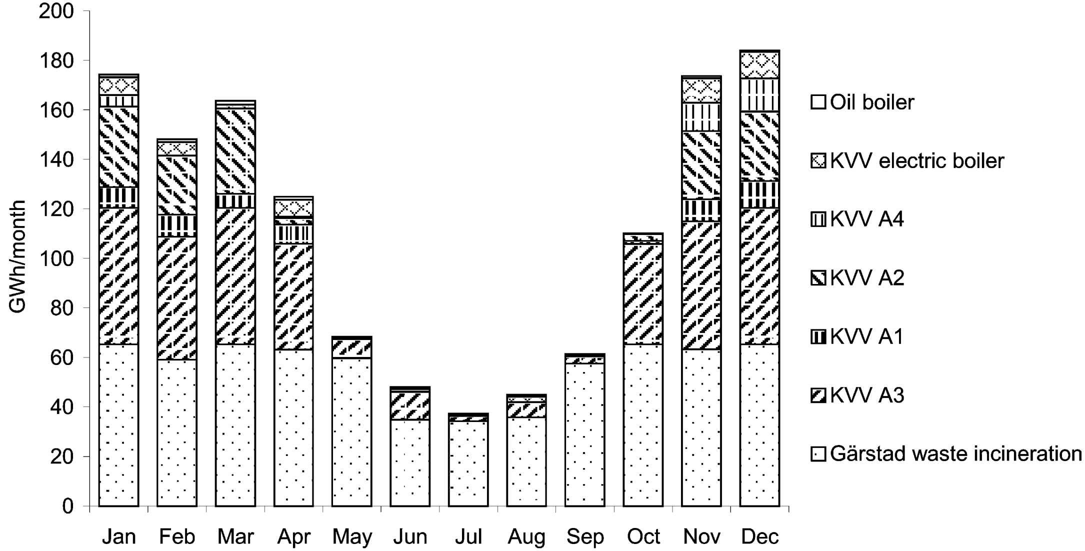


Fig. 6. Monthly district-heating production according to the Martes simulation.

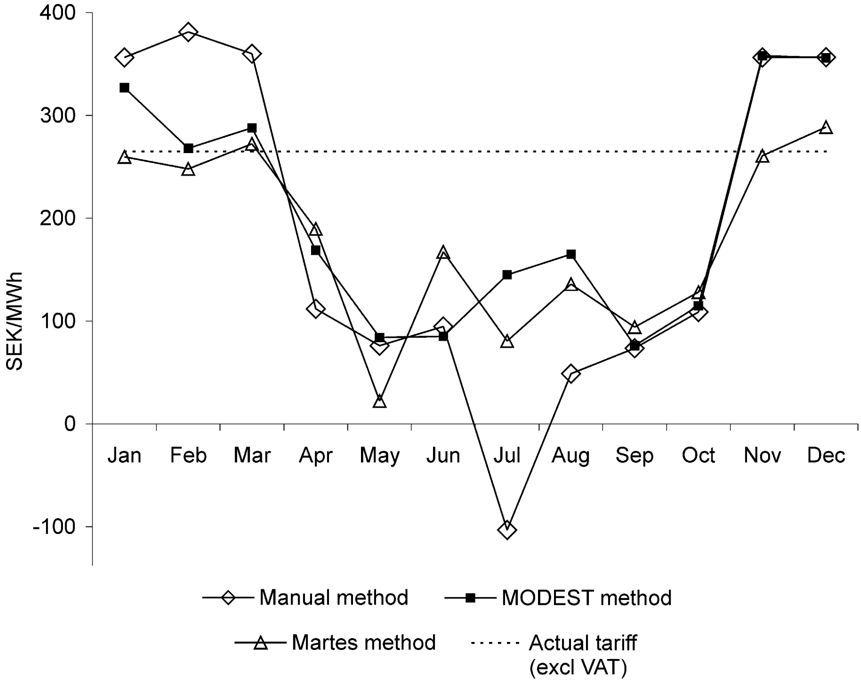


Fig. 7. Calculated marginal-costs and present district-heating tariff (excluding VAT and fixed charge).

cost in each time-period corresponds to the average variable cost for the last dispatched unit. Marginal costs can be automatically compiled and aggregated to monthly averages. The compiled monthly production of heat according to the Martes model is shown in Fig. 6. The model results are compatible with actual production in 2000 (Fig. 2).

5. Concluding discussion

The calculated marginal costs obtained with the three different methods are similar (Fig. 7). The largest difference between the methods is found in July. One explanation for this is that Martes and MODEST use load curves based on an assumed normal year, which has a higher heat load than the year used in the manual method. When using the latter method, waste incineration is assumed to cover almost all of the district-heating demand in July. Consequently, the marginal costs become lower compared to the other two methods.

Differences in the results between the methods have additional explanations. The models are based on different algorithms. There are also differences in how the energy system is depicted. It was difficult to implement the energy system in exactly the same fashion. The objective was to demonstrate the different methods' capability of calculating marginal costs for a complex utility rather than comparing the models.

The calculated marginal costs can be viewed as short-range marginal costs. They can thus be taken as a point of departure when determining the district-heating tariff. The utility also has a fixed price element in the tariff. A fixed charge can eliminate the risk of the utility running at a loss, i.e., eliminate dead weight losses arising from pure short-range marginal cost (SRMC) pricing. Using these prices based on SRMC and a fixed charge should be able to bring about a close to optimal resource-allocation.

The calculated marginal costs are lower during summer. This should be reflected in the DH tariff. However, the actual tariff in this case is fixed all year round. This signals that conservation measures undertaken by customers in order to save heat during summer are equally important or valuable as those measures saving heat during winter. Installing, e.g., complementary solar collectors at a DH customer would save district heating mainly during summer, whereas additional insulation would save heat mainly during winter. But the latter measure is more beneficial to the utility, and this should be reflected by the DH price.

Acknowledgements

The authors would like to thank John Johnson for help with the Martes model, and Heimo Zinko for comments on an earlier version of this paper. Tekniska Verken in Linköping AB is acknowledged for their support. The work has been carried out under the auspices of The Energy Systems Programme, which is financed by the Swedish Foundation for Strategic Research, the Swedish Energy Agency and Swedish industry.

References

[1] The Electricity Act. SFS 1997:857. Stockholm: The Swedish Parliament; 2002 [chapter 7, §2].
[2] The Swedish District-Heating Association. Statistics 1999. Stockholm: FVF; 2001.
[3] International Association for District Heating, District Cooling and Combined Heat-and-Power (Euroheat). District heat in Europe 1999. Brussels: Euroheat; 1999.
[4] Werner S. Fifty years with district heating in Sweden. Stockholm: The Swedish District-Heating Association; 1999.
[5] The Swedish Energy Agency. Energy in Sweden—facts and figures 2000. Eskilstuna: STEM; 2000.
[6] Andersson S, Werner S. Swedish district-heating—owners, prices and profitability. Göteborg: Chalmers University of Technology, Department of Energy Conversion; 2001 [in Swedish].
[7] Della Valle A. Short-run versus long-run marginal cost pricing. Energy Economics 1988;10(4):283–6.
[8] Bohman M, Andersson R. Short- and long-run marginal cost pricing. On their alleged equivalence. Journal of Public Economics 1987;33(4):333–56.
[9] Schramm G. Marginal-cost pricing revisited. Energy Economics 1991;13(4):245–9.
[10] Williams H. Model building in mathematical programming. Chichester: John Wiley & Sons; 1993 p. 109.
[11] Sherali H, Soyster A, Murphy F, Sen S. Linear-programming based analysis of marginal-cost pricing in electric utility capacity expansion. European Journal of Operational Research 1982;11:349–60.

[12] Nilsson K, Söderström M. Industrial applications of production planning with optimal electricity demand. Applied Energy 1993;46(2):181–92.
[13] Andersson M. Shadow prices for heat generation in time-dependent and dynamic energy systems. Energy—The International Journal 1994;19(12):1205–11.
[14] Wene C-O. In: Lundqvist L, editor. Spatial energy analysis. Aldershot: Avebury; 1989. p. 271–95.
[15] Verbruggen A. Cogeneration—allocation of joint costs. Energy Policy 1983;11(6):171–6.
[16] Fredriksen S, Werner S. District heating—theory, technology and function. Lund: Studentlitteratur; 1993 [in Swedish].
[17] Schlamadinger B, Apps M, Bohlin F, Gustavsson L, Jungmeier G, Marland G, et al. Towards a standard methodology for greenhouse-gas balances of bioenergy systems in comparison with fossil energy systems. Biomass and Bioenergy 1997;13(6):359–75.
[18] Mayerhofer P, Krewitt W, Friedrich R. ExternE core project. Extension of the accounting framework. Final report, December 1997. Stuttgart: Institute of Energy Economics and the Rational Use of Energy (IER); 1997 p. 83-86.
[19] Lucas K. On the thermodynamics of cogeneration. International Journal of Thermal Sciences 2000; 39:1039–46.
[20] Henning D. Cost minimization for a local utility through CHP, heat storage and load management. International Journal of Energy Research 1998;22(8):691–713.
[21] Henning D. Optimisation of local and national energy systems: development and use of the MODEST model. Dissertation no. 559. Linköping: University of Linköping, Division of Energy Systems; 1999.
[22] Johnsson J. Personal communication. Profu Consultants, http://www.profu.se (March 2003), Götaforsliden 13, nedre, SE-431 34, Mölndal, Sweden.
[23] Josefsson A, Johnsson J, Wene C-O. Community-based regional energy-environmental planning. In: Carraro C, Haurie A, editors. Operations research and environmental management. Kluwer Academic; 1996. p. 3–23.