17

Planning of Distributed Energy Systems with Parallel Infrastructures: A Case study

Bjorn H. Bakken
SINTEF Energy Research
Norway

1. Introduction

Traditionally, energy supply systems have been designed from a centralized perspective where the prime concern has been to cover the customers' demand for energy at minimum cost. In the increasing drive for more renewable energy and a sustainable society, changes are needed both on the supply and demand side. New technologies and advanced solutions for distributed energy systems are emerging, removing the previous clear distinction between centralised supply options and distributed passive loads. These new technologies yield better possibilities to design sustainable energy systems for the future, but also introduce more complex energy systems to design, operate and maintain. Different types of micro-cogeneration, heat pumps and possibly fuel cells create mutual influence and dependency between different infrastructures.

Furthermore, the ongoing liberalization is causing a change from previously vertically integrated (mono-energy) utilities to horizontally integrated "multi-utilities" supplying electricity, heat and gas to their customers. In a liberalized market regime, also independent energy suppliers can enter the traditional supply area of a local utility and offer their products to customers at competitive conditions. Strategic planners in energy companies thus need to consider both complementarities within their own multi-utility company and competition from others in their "home" market. Public planners, on the other hand, need to be able to give a fair and neutral evaluation of different projects across the traditional energy supply systems of electricity, heat and gas. To meet this development, more comprehensive and flexible planning tools are needed, in particular at distribution system level.

Several approaches have appeared the last years that integrate two or more energy infrastructures in the analysis. Many of these focus on the integrated operation of large scale gas (fuel) and electricity networks for optimal dispatch of generating units and/or pricing of transmission capacity (An et al., 2003; Gil et al., 2003; de Mello & Ohishi, 2005; Morais & Marangon Lima, 2003; Quelhas et al., 2006; Shahidehpour et al., 2005). Others consider downstream optimization of electricity and heat demand from cogeneration units (Henning, 1997; Sandou et al., 2005). Some attack the optimization of multiple energy carriers more generalised, incorporating electricity, gas, heat and hydrogen on the supply side as well as electricity, heating and cooling on the demand side (Aki et al., 2006; Bruckner et al., 1997; Geidl & Andersson, 2005; Lindenberger, 2000; Lindenberger, 2004). However, few, if any, of these approaches consider the issue of expansion/investment planning of such multiple infrastructures.

The area of optimal expansion planning in energy systems with multiple energy carriers is currently dominated by large scale optimisation tools for regional or global system studies like MARKAL/TIMES, EFOM, MESSAGE and similar models (Beller, 1979; Henning, 1999; Goldstein et al., 2003; Messner & Strubegger, 1995; Seebregts et al., 2001). In such large scale studies the energy system is typically represented with an aggregated type of modelling with one energy balance per energy carrier, and with resources deployed on one side and end use extracted on the other side. Various technologies are modelled with emissions and energy losses. This approach is usually sufficient for energy system studies on a national or international level. In an improved optimisation approach for expansion planning in local energy supply systems, however, different infrastructures within the geographical area of concern have to be identified. Geography, topology and timing are all key elements in this approach. It is thus not only a question of which resources and which amounts to use, but also where in the system the necessary investments should take place and when investments should be carried out.

Over the last decade, SINTEF Energy Research has been developing a new optimization model called 'eTransport' that takes into account both the topology and geographic distance of multiple energy infrastructures, and the technical and economic properties of different investment alternatives. The model employs nested optimization algorithms of linear, mixed integer and dynamic programming, calculating both the optimal diurnal operation of the given energy system and the optimal expansion plan typically 15-20 years into the future. The model offers a systematic approach to meet the challenges of planning future energy supply systems with multiple energy carriers.

In this paper, a brief documentation of the eTransport model will be given, and a case study will be presented to demonstrate the use of the model. In the case study, a supply area with variable heat and electricity demand during winter and summer periods considers investments in both electric boilers and a local CHP unit to cover increasing energy demand.

2. The eTransport model

The optimization model "eTransport" is developed for expansion planning in energy systems where several alternative energy carriers and technologies are considered simultaneously (Bakken & Holen, 2004; Bakken et al., 2007). The model uses a detailed network representation of technologies and infrastructure to enable identification of single components, cables and pipelines. The current version optimizes investments in infrastructure over a planning horizon of typically 15 to 20 years for most relevant energy carriers and conversion between these. It is not limited to continuous transport like lines, cables and pipelines, but can also include discrete transport by ship, road or rail.

The model is separated into an operational model (energy system model) and an investment model, as illustrated in Figure 1 (Bakken et al., 2007). In the operational model there are sub-models for each energy carrier and for conversion components. The operational planning horizon is relatively short (1-3 days) with a typical time-step of one hour. The operational model finds the cost-minimising diurnal operation for a given infrastructure and for given energy loads. Annual operating costs for different energy system designs are calculated by solving the operational model repeatedly for different seasons (e.g. peak load, low load, intermediate etc), investment periods (e.g. 2-5 year intervals) and relevant system designs. Annual operating and environmental costs for all different periods and energy system designs are then used by the investment model to find the investment plan that minimises the present value of all costs over the planning horizon.

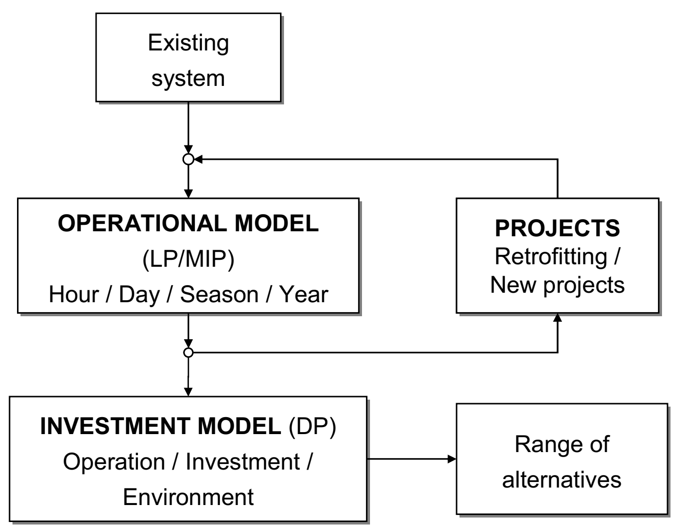

Fig. 1. Combination of operation and investment optimization in eTransport

Mathematically, the model uses a combination of linear programming (LP) and mixed integer programming (MIP) for the operational model, and dynamic programming (DP) for the investment model. The operational model is implemented in the AMPL programming language with CPLEX as solver, while the investment model is implemented in C++. A modular design ensures that new technology modules developed in AMPL for the operational model are automatically embedded in the investment model. A full-graphical drag-and-drop Windows interface is developed for the model in MS Visio. All data for a given case are stored in a database.

In the *operational model* the sub-models for different components are connected by general energy flow variables that identify the flow between energy sources, network components for transport, conversion and storage, and energy sinks like loads and markets. These general variables are included in and restricted by the various models and they are the link between the different models. The different technology models are added together to form a single linear optimisation problem where the object function is the sum of the contributions from the different models, and the restrictions of the problem include all the restrictions defined in the models. Emissions are caused by a subset of components (power plants/CHP, boilers, road/ship transport etc) that are defined as emitting CO_2, NOx, CO and SOx.

Further environmental consequences can be defined. Emissions are calculated for each module and accounted for as separate results. When emission penalties are introduced by the user (e.g. a CO_2 tax), the resulting costs are included in the objective function and thus added to operating costs.

The task for the *investment model* is to find the optimal set of investments during the period of analysis, based on investment costs for different projects and the pre-calculated annual operating costs for different periods and states. The optimal investment plan is defined as the plan that minimises the discounted present value of all costs in the planning period, i.e. operating costs plus investment costs minus the rest value of investments. The optimal plan will therefore identify the optimal design of the energy system (i.e. the optimal state) in different periods. The user defines a set of investment alternatives where each alternative typically consists of several physical components with predefined connections to the rest of the energy system. The same components can be included in several competing investment alternatives, making the different alternatives mutually exclusive from an economic point of view. Mutually exclusive alternatives will be identified by the model in the search for the best expansion plan. More details of the investment algorithm in eTransport can be found in (Bakken et al., 2007).

The combined operational and investment analysis enables a very flexible time resolution as illustrated in Figure 2. The user specifies *Hourly profiles* of prices and loads for one or more days, which are aggregated into one or more seasonal *Segments* (e.g. winter, summer, spring and autumn). The sum of the Segments equals one *Year*, which is the base for the results from the operational analysis. Yearly values of costs and emissions are input to the investment analysis, where one or more years define an *Investment period* (where the model is allowed to make investments). The sum of investment periods, which do not have to be of equal length, is the *Planning horizon* of the case.

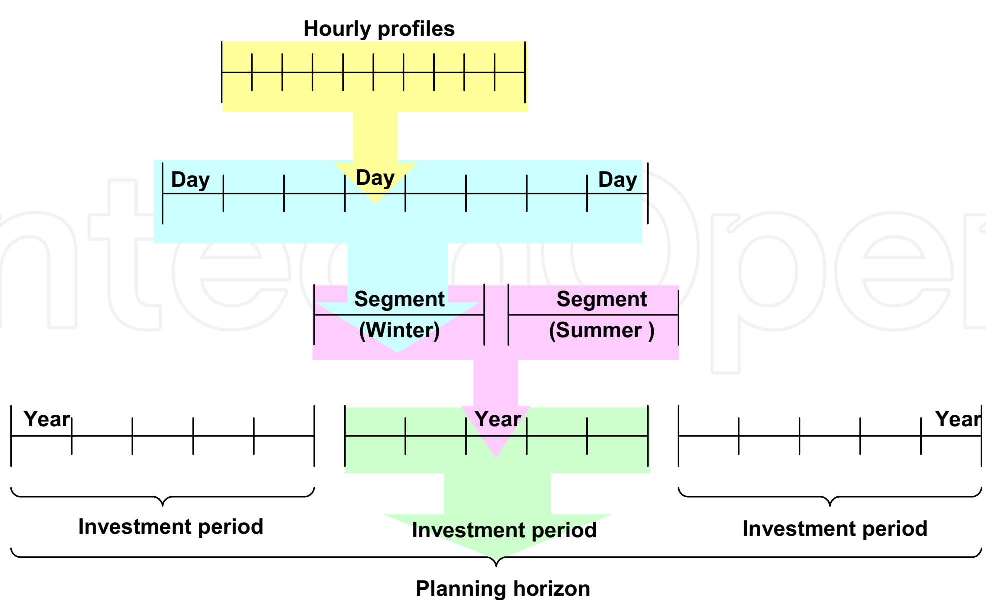

Fig. 2. Time resolution in eTransport

3. Case study

In this paper a case study is used to demonstrate the use of the eTransport model for planning of a distributed energy system with multiple infrastructures and several alternative energy sources. It is worth noting that the example is based on a real case, but the data are slightly tuned to emphasize the different aspects discussed in the paper.

3.1 Case input parameters and assumptions

The case is based on a simplified model of a small municipal/suburban area as shown in Figure 3. There is a mix of residential, service and industrial loads in the area, aggregated into 6 load centres of electricity (blue circles) and heat (red circles). The loads are supplied by a 22 kV distribution grid of underground cables (blue) and a district heating network (red). The main electricity source is the Elspot market (blue square). The old oil fired heat central is being decommissioned, and the challenge in the case is to decide whether to base the future heat supply in the area on:

i) a gas fired CHP (CHP 1),
ii) a waste fired CHP with low quality domestic waste (CHP 2),
iii) a waste/biomass fired CHP with higher quality recycled waste and wood construction materials (CHP 3), or
iv) an electric boiler.

In the case of the three CHP's, surplus electricity may be sold back to the local utility at a fixed price. Electricity demand exceeding the capacity of the CHP's has to be purchased from the Elspot market to market prices.

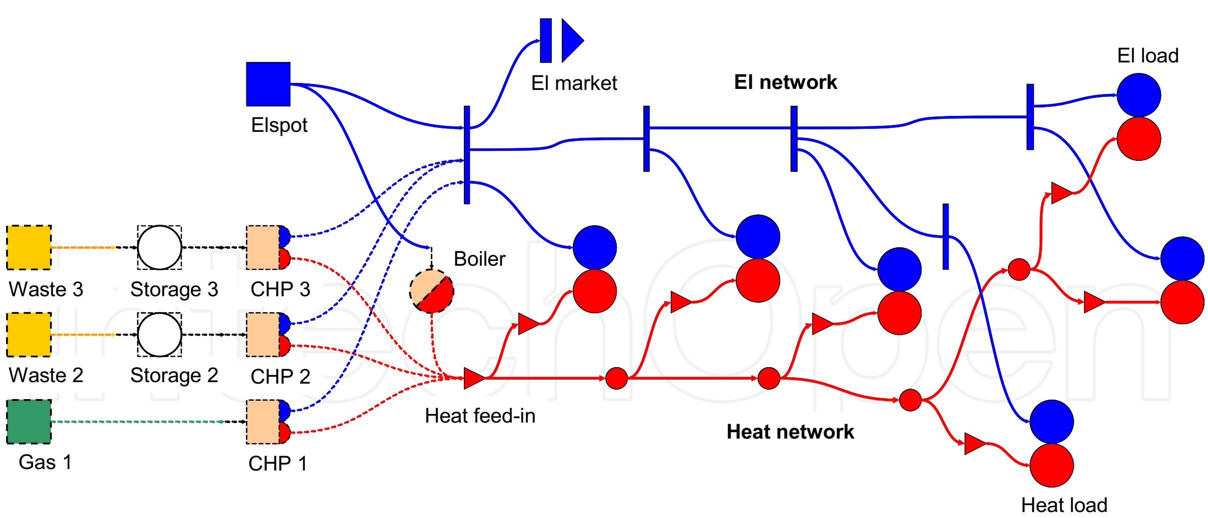

Fig. 3. Energy supply system layout

When a case model is set up as in Figure 3, special consideration has to be given to the supply of heat to the customers. Heat demand can be covered by either electricity through local boilers or direct electric heating, or by hot water from the district heating network. If both alternatives are modelled as in the left hand illustration in Figure 4, a "flip-flop" solution may occur where the model changes from electricity to district heating and back every hour depending on which supply is cheapest at any time. This would require that customers have installed multiple heat systems and is not a feasible solution, so the modeller should take care to separate electricity and heat supplies as shown in the right hand illustration of Figure 4. Physically, this implies a policy/regulatory decision that prohibit users to install electric heating equipment once the district heating system is in operation.

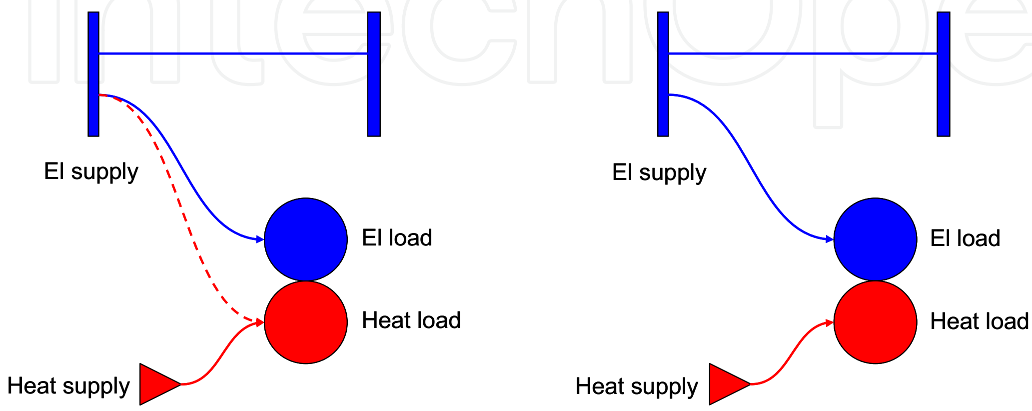

Fig. 4. Heat supply alternatives; *Left*: Multiple heat supply by electricity and heat network; *Right*: Separate electricity and heat supply.

In order to analyse the profitability of a district heating network in a new area, the network itself must be defined as part of the investment. The heat load should then be supplied from the heating network (Figure 4, Right) in the states where the network existed, and from the electricity network in the states with only electricity distribution. Such a case is however not treated in this paper, where we presume the district heating network already exists.

The planning horizon is 15 years (2010-2025), split into three 5-year investment periods. The case is set up with two annual segments: "Summer" of 265 days and "Winter" of 100 days (see Figure 2). The total load profiles for the area for the Summer segment are shown in Figure 5. For simplicity, the Winter segment has the same load profiles but they are 50% higher. The electricity loads are assumed to increase with 10% for each 5-year period, while the heat loads do not increase.

There are no renewable electricity sources in the area, so electricity has to be purchased at the Elspot market to the price shown in Figure 6 for the Summer period. The Elspot price is assumed to be 50% higher in the Winter period, but the same profile is used. Furthermore, if the municipality decides to invest in a CHP, the local utility offers to purchase surplus electricity at a fixed price of 20 Euro/MWh. The Elspot price is assumed to increase 10% for each 5-year period. The interest rate is set to 5% pa.

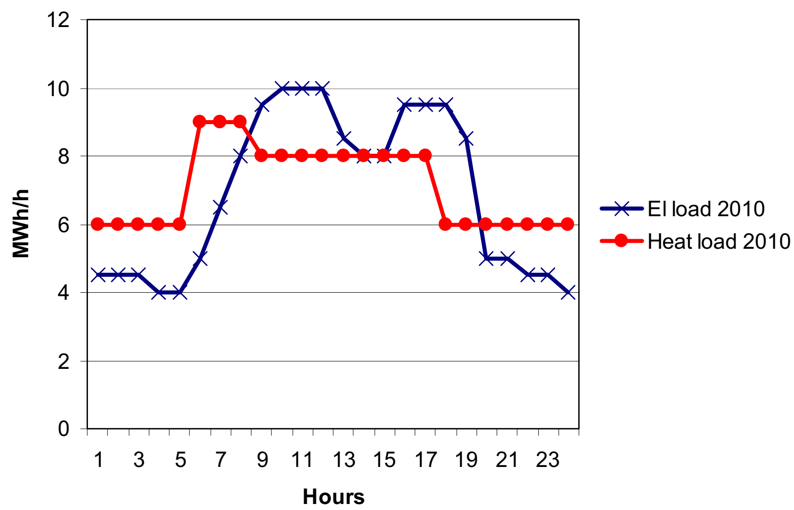

Fig. 5. Total electricity and heat loads in "Summer" period 2010 (MWh/h)

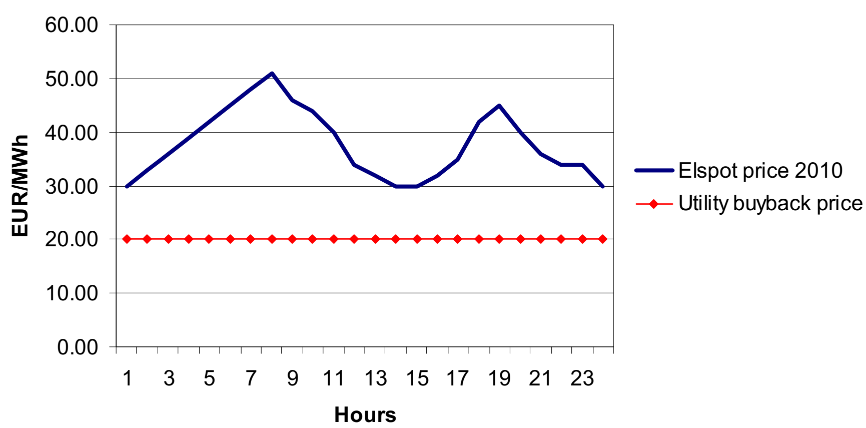

Fig. 6. Elspot market price and utility buyback price in "Summer" period 2010 (EUR/MWh)

Table 1 summarizes the main technical and economic parameters for the four investment alternatives. We assume the same contractor is offering both waste fired units (CHP 2 and CHP 3) as alternative designs for the same investment cost. However, the domestic waste has lower quality than the recycled biomass, so both fuel cost and unit efficiency is lower.

Unit	**Fuel**	**Fuel price**	**Unit rating (MW)**	**Unit efficiency (El / Heat)**	**CAPEX (1000 EUR)**	**OPEX (EUR/year)**	**Service life (years)**
Boiler	Electricity	30-51 EUR/MWh	15	- / 0.9	500	0	30
CHP 1	Gas	0.3 EUR/Sm³	35	0.4 / 0.45	5 000	50 000	30
CHP 2	Waste	10 EUR/MWh	20	0.3 / 0.4	10 000	70 000	25
CHP 3	Waste	25 EUR/MWh	20	0.35 / 0.4	10 000	60 000	25

Table 1. Basic data for investment alternatives

In some cases the cost of domestic waste can even be negative. The municipality can be obliged to collect and dispose of waste in a safe way, and the alternative cost to incineration can be high. In this case, however, we set a positive but low cost for the waste fuel.

3.2 Results based on initial assumptions

Due to limitations in the waste supply, the rating of the waste units is lower than the gas fired CHP. The model is therefore allowed to combine the electric boiler with the two waste fired CHP's, while the gas fired CHP is large enough to supply the whole heat load alone. Note that the case only deals with the total unit rating, and does not consider whether the heat central consists of one large or several smaller units for backup/redundancy.

With initial assumptions of investments and fuel prices as given above Figure 7 shows the resulting ranking of the alternatives. The CHP 2 unit with cheap domestic waste in combination with the electric boiler turns out to be the cheapest alternative with an annuity of 4.4 mill. Euro. The gas fired CHP 1 unit comes in second place with an annuity of 5.4 mill. Euro. The waste fired CHP 3 comes in third place while the electric boiler is last. The boiler itself has lowest investment cost, but the purchase of electricity for heat production causes the operational costs to exceed the other alternatives. Figure 8 shows that all investments are made in the first investment period.

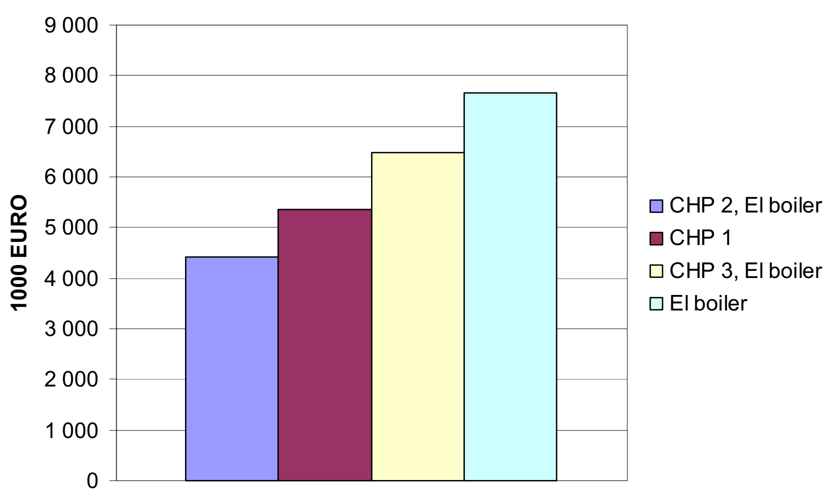

Fig. 7. Ranking of investment alternatives based on annuity of total system cost over planning horizon

The operation of the system can be examined by inspecting the energy profiles of different components. All variables for all components in all segments and investment periods are available to the user in the eTransport user interface, and can also be exported to Excel for further documentation as in this paper. Figure 9 shows the operating profiles of the CHP 2 and the boiler in the "Summer" period in 2010, i.e. the low load period in the first year (corresponding to the load situation shown in Figure 5). Already in this period the CHP is rather heavily loaded, while the boiler is used during peak load hours only. The corresponding electricity generation is shown in Figure 10. As small amount of surplus electricity is sold back to the local utility during the day, but most of the time electricity has to be purchased from the Elspot market.

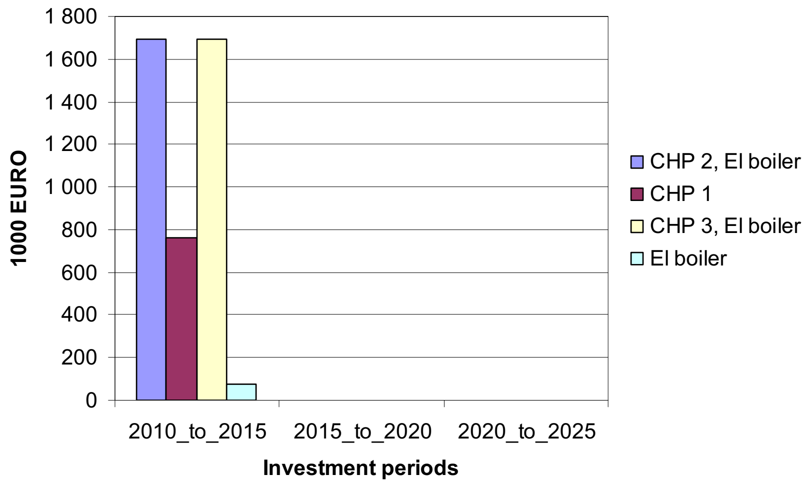

Fig. 8. Investments (costs shown as annuities over the 5-year investment periods)

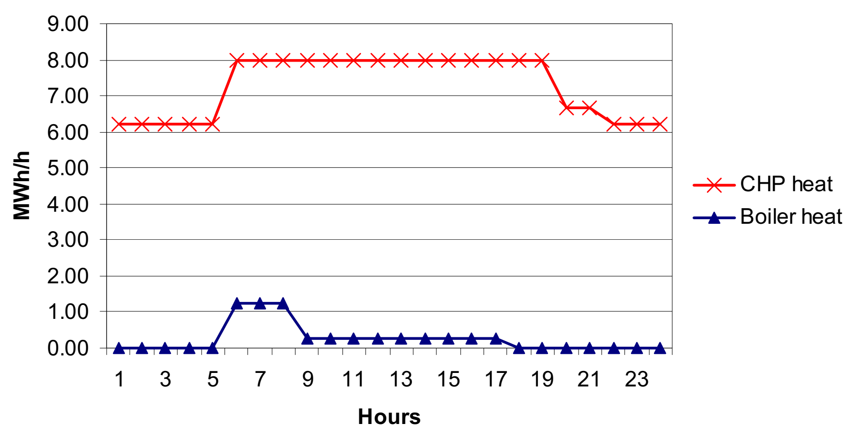

Fig. 9. Heat production from boiler and CHP 2 in "Summer" period 2010 (MWh/h)

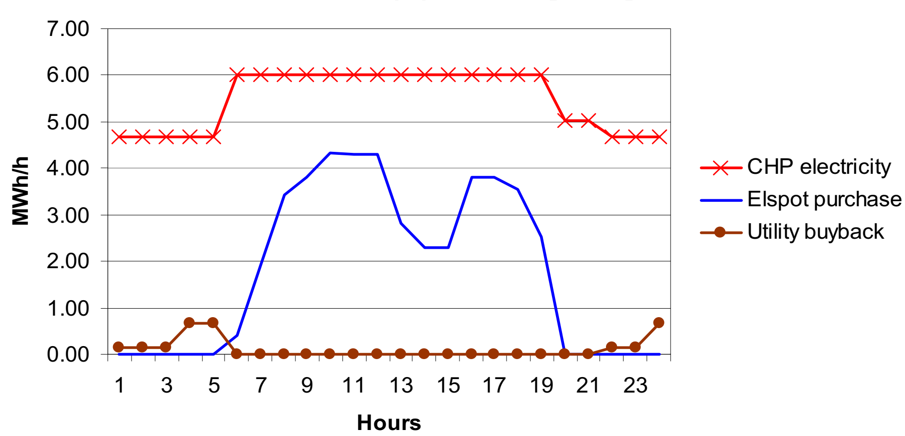

Fig. 10. Electricity production from CHP 2, Elspot purchase and sales of surplus electricity in "Summer" period 2010 (MWh/h)

For comparison, we can show the same variables for the "Winter" period in 2020, i.e. the period of heaviest load in the case. Figure 11 shows that the CHP is running full load all day, and also the boiler has to be in operation the whole day to cover the rest of the load. There is still sufficient capacity in the system to supply the needed heat, but the CHP is obviously due for an upgrade. Similarly, Figure 12 shows that a large amount of electricity has to be purchased from the Elspot market. There is no surplus electricity to sell back to the local utility at this stage.

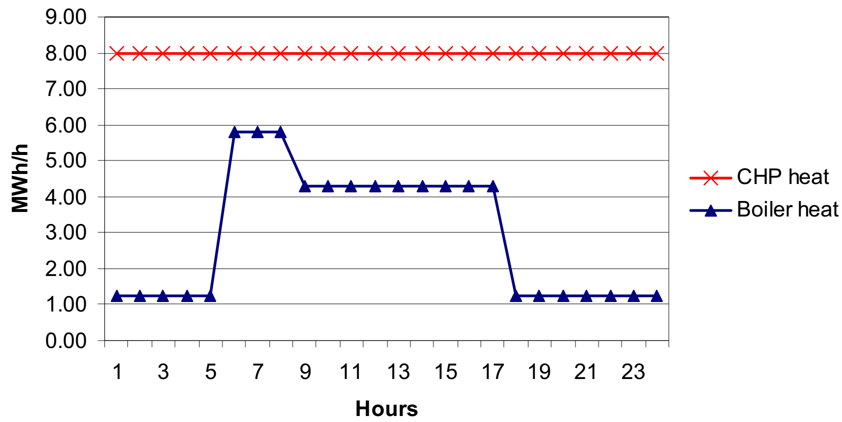

Fig. 11. Heat production from boiler and CHP 2 in "Winter" period 2020 (MWh/h)

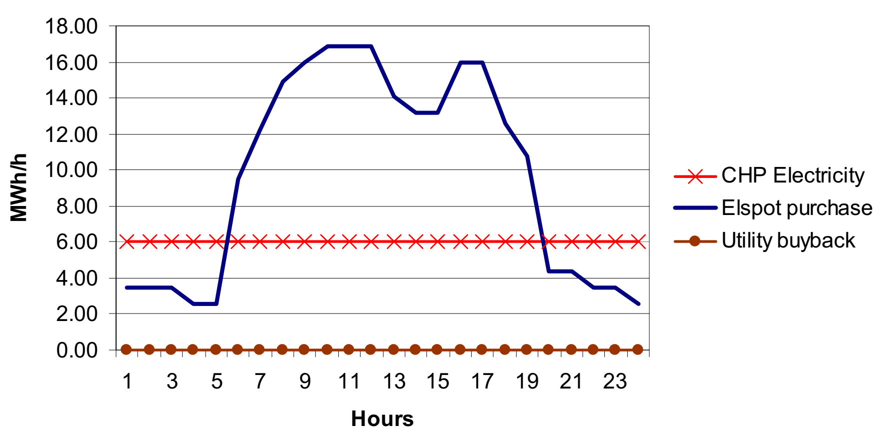

Fig. 12. Electricity production from CHP 2, Elspot purchase and sales of surplus electricity in "Winter" period 2020 (MWh/h)

3.3 Re-negotiation of gas price

As a second step, let us assume that the gas supplier is not satisfied with second place in the investment analysis. He therefore returns to the municipality with an offer for a long-term gas contract at the reduced price of 0.2 EUR/Sm^3.

When all other parameters are kept at initial values, a re-run of the analysis with reduced gas price allows the gas fired CHP 1 to move up to first place with the reduced annuity of 3.8 mill. Euro, as shown in Figure 13. Figure 14 shows that all investments are again made in the first period.

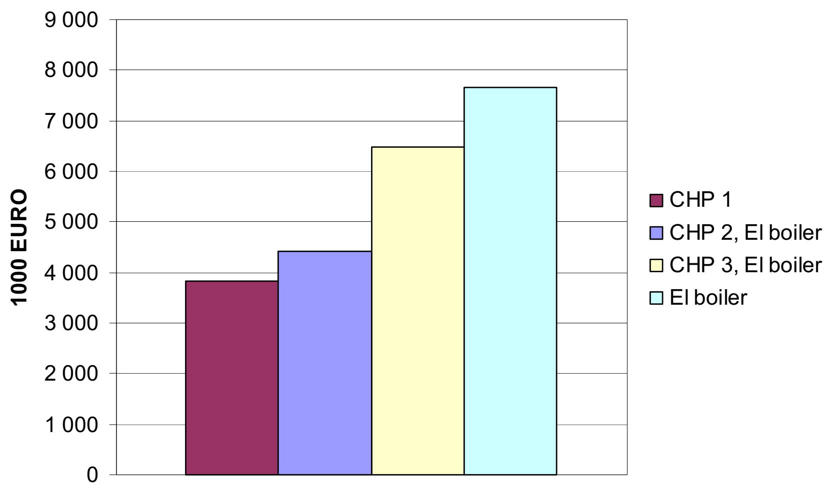

Fig. 13. Ranking of investment alternatives based on annuity of total system cost over period of analysis

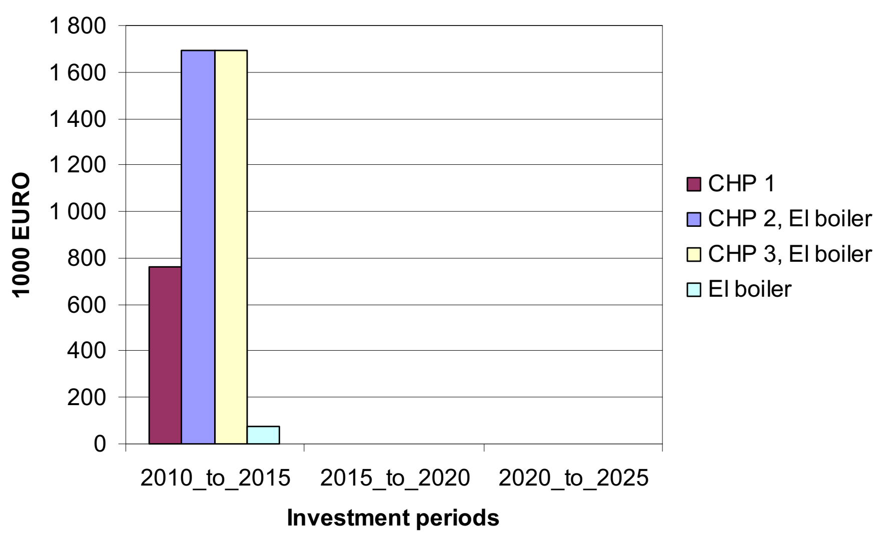

Fig. 14. Investments (costs shown as annuities over the 5-year investment periods)

In this case, the gas fired CHP 1 is large enough to cover the full heat load, but it is more interesting to examine the electricity balance. Figure 15 shows the electricity production, the purchase from the Elspot market and the electricity sold back to the local utility in the "Summer" period of 2010. The hourly distribution between CHP production, Elspot purchase and electricity sales is defined by the relation between the energy prices, so the CHP is not running full load all day to minimize purchase from the Elspot market.

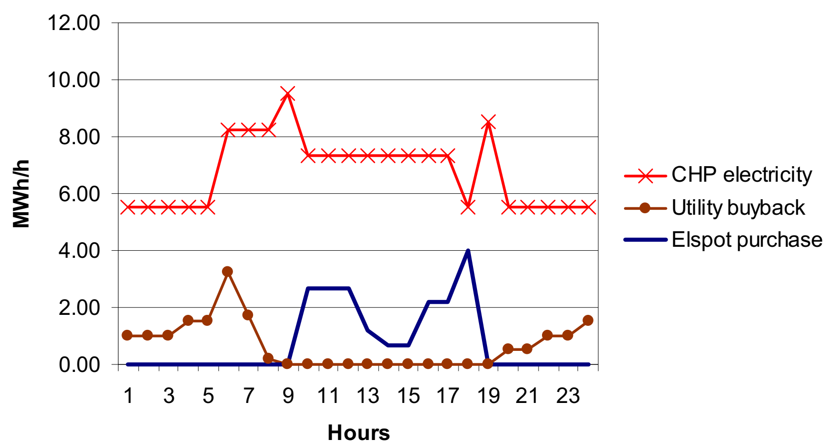

Fig. 15. Electricity production from CHP 1, Elspot purchase and sales of surplus electricity in "Summer" period 2010 (MWh/h)

Moving to the heavy load period of 2020 in Figure 16, the picture is similar. However, now the load is so high that the CHP has to run full load during peak hours and still electricity has to be purchased to cover the load. During off-peak hours some electricity is still sold back to the utility.

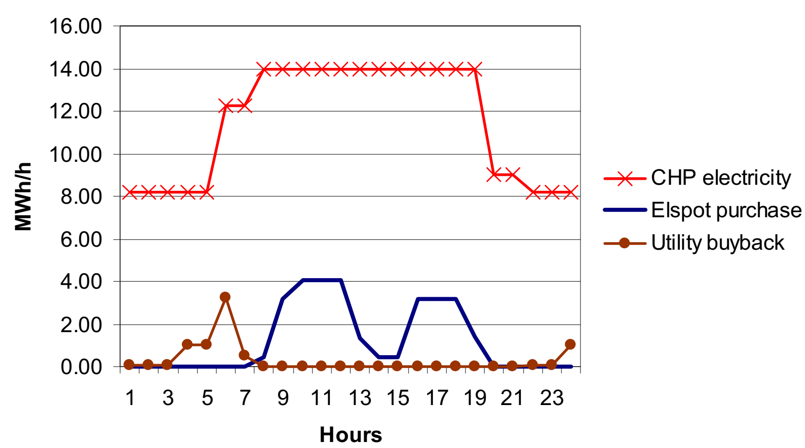

Fig. 16. Electricity production from CHP 1, Elspot purchase and sales of surplus electricity in "Winter" period 2020 (MWh/h)

The gas supplier is naturally satisfied with the changed outcome. However, let us further assume the "Green Party" in the municipality raises the question of CO_2 emissions. The gas fired unit causes average CO_2 emissions of 37.78 tonnes/year over the period of analysis. The domestic waste of CHP 2, on the other hand, is estimated to consist of 40% fossil waste and 60% organic waste, the latter considered as CO_2 neutral. The recycled wood waste of CHP 3 is also CO_2 neutral. Assuming the Elspot electricity is produced with the Norwegian generation portfolio of 99% hydropower, also the electricity can be considered as CO_2 free.

A sensitivity analysis shows that the waste fired CHP 2 moves back as cheaper than the gas fired CHP 1 for a CO_2 tax above 25 Euro/tonne. Although higher than current CO_2 prices, this causes some concern in the municipality. The final decision is to build the waste fired unit CHP 2 in combination with the electric boiler as peak load/backup unit.

3.4 Delayed commissioning

The municipality has decided to sign a contract for the waste fuelled CHP 2. However, such technologies are still quite young, so in a final sensitivity analysis we assume there will be problems with the delivery and/or commissioning of the unit. This is modelled as a delay in the CHP 2 investment until the second investment period (2015), changing also the cash flows accordingly. Figure 17 shows that in this case the gas fired unit CHP 1 again moves up as cheapest alternative even with the original gas price of 0.3 Euro/Sm^3.

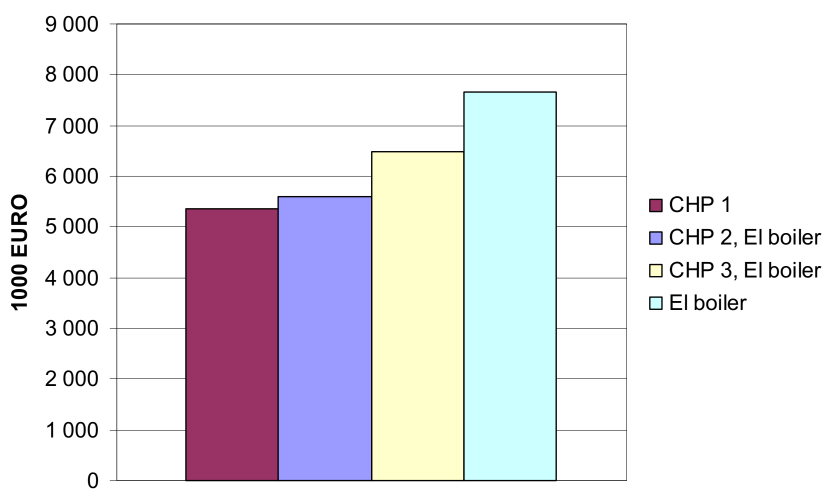

Fig. 17. Ranking of investment alternatives based on annuity of total system cost over period of analysis

Another interesting observation from Figure 18 is that the electric boiler is put into operation in 2010, while the CHP 2 does not come online until 2015. The added operational expenses of supplying heat only from electricity for the first 5 years cause the waste alternative to come in second place.

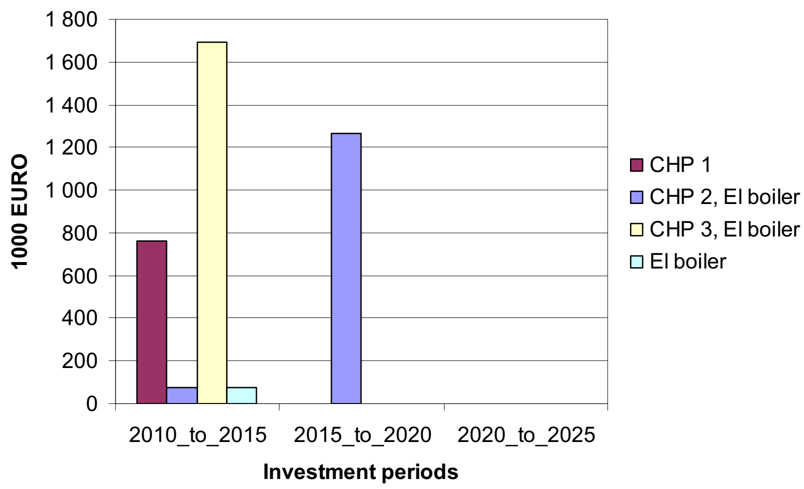

Fig. 18. Investments (costs shown as annuities over the 5-year investment periods)

4. Summary

This paper has presented a novel optimization model 'eTransport' for planning of distributed energy supply systems with parallel infrastructures. The model minimises total energy system costs (investments, operation and emissions) of meeting predefined energy demands of electricity, space heating and tap water heating within a geographical area over a given planning horizon. Many topographical details can be included for the different supply infrastructures (electricity, natural gas, biomass, waste, district heating etc), and this makes the model especially appropriate for local energy planning e.g. in municipalities or cities.

The main user group for the eTransport model are decision makers involved in planning of local energy service systems including new DG plants. Local authorities (e.g. municipalities) need to analyze the local energy system with respect to concessions and/or energy planning. It is also useful for utilities that do regional energy studies, including large energy suppliers that must find the least-cost option for their supply. Governmental agencies that give investment subsidies on basis of socio-economic efficiency can also use the model to analyse the effects of the support.

The model currently employs a nested optimization of mixed integer programming and dynamic programming, calculating both the optimal diurnal operation of the complete energy system and the optimal expansion plan typically 20-30 years into the future. A full graphical user interface is also developed to increase the user-friendliness of the model. In the next version stochastic optimization is implemented to handle uncertainties in energy prices, demand and investments.

The main focus of this paper has not been the optimisation algorithm itself; rather the usefulness of such an optimisation model is demonstrated though a case study. Initially, the model is used to find the least-cost alternative for future energy supply in a suburb or municipality. Then various assumptions are changed to see how the results are affected. The case study uses fictive input data that have been tuned to show the effects of various changes. Usually, the process of analysing the sensitivity of different solutions to changes in parameters is done offline by an analyst and presented afterwards. However, due to the full graphic user interface developed for the eTransport model, sensitivity analyses can also be performed "live" with municipal or corporate decision makers present. This will enhance the involvement of the decision makers and thus increase the value of the analysis. This is especially important in the case of municipal planning, where political decision makers may have low technical competence.

5. Acknowledgement

The author gratefully acknowledges the support from the Research Council of Norway and from the sponsors of the "eTransport" development.

6. References

Aki, H.; Yamamoto, S.; Kondoh, J.; Maeda, T.; Yamaguchi, H.; Murata, A. & Ishii, I. (2006). Fuel cells and energy networks of electricity, heat and hydrogen in residential areas, *Hydrogen Energy*, Vol. 31, 2006, 967-980

An, S.; Li, Q. & Gedra, T.W. (2003). Natural gas and electricity optimal power flow, *Proceedings of IEEE PES 2003 Transmission and Distribution Conference*, pp. 138-143, Dallas, USA

Bakken, B.H. & Holen, A.T. (2004). Energy service systems: Integrated planning case studies, *Proceedings of IEEE PES 2004 General Meeting*, Denver, USA, 2004

Bakken, B.H.; Skjelbred, H.I. & Wolfgang, O (2007). eTransport: Investment Planning in Energy Supply Systems with Multiple Energy Carriers, *Energy*, Vol. 32, 2007, 1676-1689

Beller, M. (1979). The Applications of Energy Systems Analysis to Policy and Technology Studies, *Proceedings of Int. Conf. of Energy Systems Analysis*, Dublin, Ireland, 1979

Bruckner, T.; Groscurth, H.M. & Kümmel, R. (1997). Competition and synergy between energy technologies in municipal energy systems, *Energy*, Vol. 22, No. 10, 1997, 1005-1014

Geidl, M. & Andersson, G. (2005). A modeling and optimization approach for multiple energy carrier power flow. *Proceedings of IEEE PES 2005 PowerTech Conference*, St. Petersburg, Russian Federation, 2005.

Gil, E.M.; Quelhas, A.M.; McCalley, J.D. & Van Voorhis, T. (2003). Modeling integrated energy transportation networks for analysis of economic efficiency and network interdependencies, *Proceedings of 35th North American Power Symposium (NAPS)*, Rolla, USA, 2003

Goldstein, G.A.; Kanudi, A. & Loulou, R. (2003). *MARKAL: An Energy-Environment-Economic Model for Sustainable Development*, International Resources Group, NESCAUM, Boston, USA, 2003. Available from: http://www.nescaum.org

Henning, D. (1997). MODEST – An Energy-System Optimisation Model Applicable to Local Utilities and Countries, *Energy,* Vol. 22, No. 12, 1997, 1135-1150

Henning, D. (1999). *Optimisation of Local and National Energy Systems. Development and Use of the MODEST Model*, PhD Dissertation, Linköping University, ISBN 91-7219-391-1, Linköping, Sweden

Lindenberger, D.; Bruckner, T.; Groscurth, H.M. & Kümmel, R. (2000) Optimization of solar district heating systems: Seasonal storage, heat pumps and cogeneration, *Energy*, Vol. 25, 2000, 591-608

Lindenberger, D.; Bruckner, T.; Morrison, R.; Groscurth, H.M. & Kümmel, R. (2004). Modernization of local energy systems, *Energy*, Vol. 29, 2004, 245-256

de Mello, O.D. & Ohishi, T. (2005). An integrated dispatch model of gas supply and thermoelectric systems. *Proceedings of 15th Power Systems Computation Conference*, Liege, Belgium, 2005

Messner, S. & Strubegger, M. (1995). *User's Guide for MESSAGE III, WP-95-69,* International Institute for Applied Systems Analysis, Laxenburg, Austria, 1995. Available from: http://www.iiasa.ac.at/Research/ECS/docs/MESSAGE_man018.pdf

Morais, M.S. & Marangon Lima, J.W. (2003). Natural gas network pricing and its influence on electricity and gas markets, *Proceedings of IEEE PES 2003 PowerTech Conference*, Bologna, Italy, 2003

Quelhas, A.M.; Gil, E. & McCalley JD (2006). Nodal prices in an integrated energy system. *Int. Journal of Critical Infrastructures,* Vol. 2, No. 1, 2006, 50-69

Sandou, G.; Font, S.; Tebbani, S.; Hiret, A. & Mondon, C. (2005). Short term optimization of cogeneration systems considering heat and electricity demands. *Proceedings of 15th Power Systems Computation Conference*, Liege, Belgium, 2005

Seebregts, J.; Goldstein, G.A. & Smekens, K. (2001). Energy/Environmental Modeling with the MARKAL Family of Models. In: *2001 Int. Conf. on Operations Research (OR 2001)*, Chamoni, P.; Leisten, R.; Martin, A.; Minnemann, J. & Stadtler, H. (Ed.), Duisburg, Germany, 2001

Shahidehpour, M.; Fu, Y. & Wiedman, T. (2005). Impact of natural gas infrastructure on electric power systems. *Proceedings of the IEEE,* Vol. 93, No. 5, 2005, 1042–1056

Renewable Energy

Edited by T J Hammons

ISBN 978-953-7619-52-7
Hard cover, 580 pages
Publisher InTech
Published online 01, December, 2009
Published in print edition December, 2009

Renewable Energy is energy generated from natural resources-such as sunlight, wind, rain, tides and geothermal heat-which are naturally replenished. In 2008, about 18% of global final energy consumption came from renewables, with 13% coming from traditional biomass, such as wood burning. Hydroelectricity was the next largest renewable source, providing 3% (15% of global electricity generation), followed by solar hot water/heating, which contributed with 1.3%. Modern technologies, such as geothermal energy, wind power, solar power, and ocean energy together provided some 0.8% of final energy consumption. The book provides a forum for dissemination and exchange of up-to-date scientific information on theoretical, generic and applied areas of knowledge. The topics deal with new devices and circuits for energy systems, photovoltaic and solar thermal, wind energy systems, tidal and wave energy, fuel cell systems, bio energy and geo-energy, sustainable energy resources and systems, energy storage systems, energy market management and economics, off-grid isolated energy systems, energy in transportation systems, energy resources for portable electronics, intelligent energy power transmission, distribution and inter-connectors, energy efficient utilization, environmental issues, energy harvesting, nanotechnology in energy, policy issues on renewable energy, building design, power electronics in energy conversion, new materials for energy resources, and RF and magnetic field energy devices.