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Power-to-gas plants in a future Nordic district heating system

Jussi Ikäheimo[a]*

[a]VTT Technical Research Center of Finland, Koivurannantie 1, FI-40101 Jyväskylä, Finland

Abstract

Power-to-gas (P2G) technology has been suggested as one way to balance the variability of renewable power generation and decarbonize the transport sector. This paper studies the application of P2G plant in a real Finnish municipal district heating system in a future situation where the European power and district heating sectors have been decarbonized. From the point of view of the district heating company, the P2G plant can act as fuel producer, CO_2 sink and heat source.

The district heating unit commitment (DHUC) model was used to optimize the full-year hourly resolved operation of a CHP CCS plant, heat boilers, heat pumps, P2G plant and heat storages. Capacity optimization of most plants was also done. The hourly power price variability was obtained from regional unit commitment and economic dispatch simulation of the North European region. We find that a P2G plant may be profitable in the system, starting with SNG value of 70 €/MWh and depending on the specific investment. The regional simulations show that the market value of SNG is greater than this, and we conclude that P2G is a viable option.

Keywords: power-to-gas; power-based fuels; district heating; combined heat and power; solar district heating

1. Introduction

Solar power, wind power and solar thermal energy are plagued by variability, seasonality and uncertainty. Power-to-gas (P2G or PtCH4) is a promising solution to balance the electric grid, which can effectively contribute to reducing

* Corresponding author. Tel.: +358 20 722 5764; fax: +358 14 617 058.
E-mail address: jussi.ikaheimo@vtt.fi

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the uncertainty of dispatch plans [1]. Power-to-gas technology converts power produced by renewables into hydrogen via water electrolysis, and through methanation further into synthetic natural gas. The rationales for synthesis to methane are the challenges related to distribution and use of hydrogen whereas in the case of methane the existing infrastructure can be used [2], [3]. The technology is especially suited for long-term storage because the cost of storing methane is low.

In Nordic countries heating of buildings is a significant energy consumer. District heating, especially combined with CHP is recognized as an efficient way of supplying heat and its market share in Northern Europe is high. In Finland district heating supplies heat to 50 % all residents in the whole country but in most cities the share is more than 90 %. Carbon capture and storage (CCS) and carbon capture and utilization (CCU) are also expected to become important solutions for emissions reduction in the future [4]. Integration of power-to-gas in this setting could be an interesting opportunity. Power-to-gas can produces renewable fuel and bind carbon dioxide, which otherwise would have to be vented to atmosphere or stored geologically.

There are a few papers which have included integration of district heat or CHP in P2G analyses. Kötter et al [5] studied the application of P2G in an energy supply system with 100% renewable energy in an model region in southwest Germany. They concentrated on the electrical system but district heat was also included with SNG-fired CHP and power-to-heat as heat producers. Tsupari et al [2] studied the integration of P2G with CHP plant by oxygen enriched air combustion where the oxygen from electrolysis is used to increase the heat output of the CHP plant. Brandstätt et al [6] studied the present and future economics of heat storages and P2G in a small-scale district heating network.

In this paper the operation and economic feasibility of P2G from the future Nordic district heating system point of view is evaluated. The analysis considers a biomass-fired CHP plant with carbon capture as the possible CO_2 source and site of heat integration. A medium-sized Finnish city was taken as an example heating network. The system faced hourly-varying electricity prices, which were determined by a separate multinational model.

Nomenclature

CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
DAC	Direct Air Capture
EN	European Standard
ETS	Emissions Trading System
kW_e	kilowatt-electric
kW_{th}	kilowatt-thermal
LHV	Lower Heating Value
MEA	Monoethanolamine
MW_{fuel}	Megawatt-fuel
O&M	Operating and Maintenance
PCC	Post-Combustion Capture
PEM	Proton Exchange Membrane
P2G	Power-to-Gas
PtCH4	Power-to-methane
SNG	Synthetic Natural Gas

2. Methods and assumptions

2.1. Simulation model

The District Heating Unit Commitment (DHUC) model was used to determine the optimal operation of heat and electricity producing plants, power-to-gas and storages. Plant and storage capacities were also optimized with the exception of the CHP plant, whose capacity was set exogenously. DHUC is an hourly-resolved deterministic mixed-integer linear programming model, which considers a full year of operation. The model seeks the optimum system operation and composition from the point of view of minimum systemic costs, including capital costs, operating and maintenance costs, fuel costs and taxes. The model minimizes costs taking into account demand constraints, storage constraints and plant operational constraints. The model was significantly improved since it was used to analyze the operation of power plants in a real case in Finland [7].

Fig 1 shows the components and pathways of energy and gases in the model. District heat may be produced by CHP plant, heat pumps, solar thermal collector fields or boilers. Hydrogen is produced by electrolysis and is converted into synthetic natural gas in methanation process, together with the CO_2 captured from the flue gases of the CHP plant. CO_2 may also be exported to permanent geological storage if it is not needed by methanation.

2.2. Power-to-gas plant

The power-to-gas plant consists of the electrolysis and methanation sections and possible hydrogen storage. Several technologies are possible for both processes. According to Gahleitner [8] the advantages of PEM electrolysis include faster cold start and higher flexibility. Götz et al [9] mention the availability of high-quality heat and suitability for large plants as advantages of chemical methanation. We can thus take these technologies as the basis for cost and efficiency estimation.

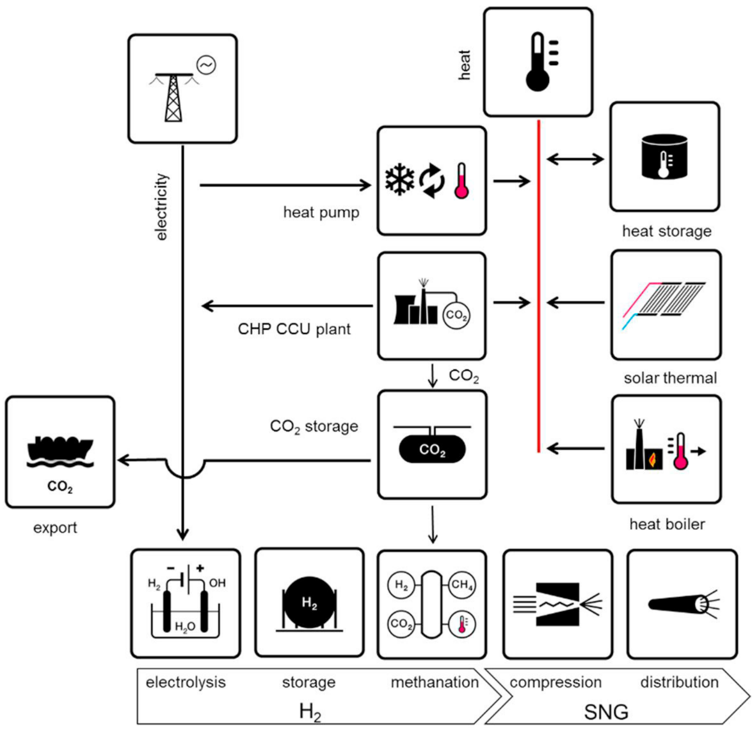

Fig 1. Components and flow chart of the DHUC energy system model.

Bertuolucci et al [10] anticipate the future investment cost of PEM electrolysis in 2030 to be 760 €/kW but with wide range of uncertainty 250–1270 €/kW. For alkaline electrolysis their central estimate is 580 €/kW. DLR et al estimated the PEM electrolysis future investment cost for a large 100 MW plant to be 400 €/kW. Grond et al [11] estimate that the investment cost of megawatt-scale chemical methanation plants could be in the range 300–500 €/kW$_{CH4}$. The methanation capacity can be lower than that of electrolysis if the dynamic operation is stabilized with a hydrogen storage [12]. Aicher et al [12] mention 5.8 €/kWh$_{H2}$ as the cost of pressurized hydrogen storage. Thus a 24-hour storage would cost 100 €/kW, referring to the electrolysis input power. Evaluating the size of the hydrogen storage is not in the scope of this work.

Tsupari et al [2] assumed 1750 €/kW plus 15 % for balance of plant as the near-term investment cost of the whole P2G plant and 2 % of the investment cost as fixed operating and maintenance (O&M) costs. Jentsch et al [13] used 750 €/kW for a future 85 % renewable energy scenario.

Bertuolucci et al [10] anticipate that the efficiency of PEM electrolysis in 2030 could be 44–53 kWh/kg$_{H2}$ which translates to 62–76 % based on lower heating value (LHV). Their central estimate is 47 kWh/kg$_{H2}$. Heat recovery is possible from methanation process. Götz et al [9] use 78 % as the methanation efficiency. They also present 15 % of the input energy as useful heat but also mention that low-temperature heat from electrolysis could be used for district heating.

As the costs estimates vary widely, we study investment costs between 750–1250 €/kW as shown in Table 3. This is formed by the cost of electrolysis, hydrogen storage and methanation. If 100 % methanation capacity and 55 % conversion efficiency from power to methane is assumed, methanation would contribute 170–280 €/kW based on the electrolysis input power [11]. If hydrogen storage contributes 100–200 €/kW (again based on the electrolysis input power), the cost electrolysis would thus lie between 270–980 €/kW, well in accordance with [10]. The cost of balance-of-plant components is not included in this estimate. The efficiency parameters are shown in Table 1.

2.3. CHP power plant

A circulating fluidized bed extraction-condensing CHP power plant was assumed to be the main heat generation unit in most cases considered in this study because of the good availability of biomass and important role of CHP in Nordic countries. This type of plant is also rather flexible in producing either power or heat. Some technical parameters of the plant are shown in Table 2 and costs in Table 3. The default size of the plant was thus set to 450 MW$_{fuel}$ (half of the peak load) but the case where no CHP plant was present was also simulated.

2.4. Heat pumps and district heating boilers

The maximum capacity of heat pumps was limited to 280 MW. More than 100 MW could be available from local exhaust air heat pumps and 180 MW from sewage or sea. Biomass and gas fired boilers were included in district heat production. The capital investment in each plant type was optimized. To avoid fossil fuels, gas-fired boilers were only able to use SNG as fuel.

Table 1. Efficiency parameters used for the P2G plant.

Parameter	Value	Unit
Electrolyser efficiency	47	kWh/kg$_{H2}$
Methanation efficiency	77	% (LHV)
Heat recovery	20	% of input electricity

Table 2. Technical parameters for the CHP plant.

Parameter	Value	Unit
fuel	90 % wood, 10 % peat	–
fuel power	450	MW
power-to-heat ratio	0.64	–
maximum total efficiency	91	%
maximum electrical efficiency	42	%
minimum load	35	%
start-up cost	70,000	€

2.5. Solar thermal plants

Solar thermal district heating was simulated based on hourly measurements of year 2011 of air temperature and global horizontal irradiation by the Finnish Meteorological Institute. To calculate the plane-of-array irradiation the global irradiation should be separated into beam and diffuse components. Many correlation models have been presented between the sky clearness index and the share of diffuse irradiation [14]. One such model was chosen here and the heat production was then calculated by the polynomial equation presented in standard EN12975 [15]. We used typical loss parameters for flat-plate collectors. The area of the collectors was decided by the optimization model or set exogenously depending on the case. All collectors were assumed to be facing south in 45 ° inclination. Costs are shown in Table 3.

2.6. Heat storages

Heat storages are important element components in the district heating network which can decouple heat generation and consumption. According to Schmidt and Miedaner [16] the investment cost of tank thermal storage in the 10,000 m^3 range is between 150–200 €/m^3, which translates to about 3.8–5.0 €/kWh_{th}. In this work 4.3 €/kWh_{th} was used as investment cost and annual operation and maintenance cost was 2 % of the investment.

Table 3. Economic parameters used for power and heat generation and storage technologies.

Conversion technology	fuel	Investment cost	Annual fixed O&M	Variable O&M
CFB CHP	biomass	2000 €/kW_e	60 €/kW	4 €/MWh
heat pump	electricity	520 €/kW_{th}	6 €/kW_{th}	–
power-to-gas	electricity	750–1250 €/kW_e	10 €/kW_e	3 €/MWh
solar thermal	–	280 €/m^2	2.5 €/kW_{th}	–
biomass boiler	biomass	370 €/kW_{th}	3 €/kW_{th}	4 €/MWh
gas boiler	SNG	80 €/kW_{th}	2 €/kW_{th}	4 €/MWh

2.7. CO_2 capture and storage

Chemical solvent absorption is widely recognized as a practical method for the industrial-scale development due to its commercial maturity [17]. Amine scrubbing technology for CO_2 separation, which has been used in the gas processing industry for decades, is considered the dominant technology for large-scale post-combustion CO_2 capture

(PCC). Although monoethanolamine (MEA) is widely considered as a benchmarking amine solvent, the deployment of MEA-based PCC is still hindered by its high capital cost and parasitic energy consumption [18]. Li et al estimate the investment cost of a MEA-based PCC plant for a large coal plant to be US$ 1357 per kW of power plant electrical capacity. In terms of CO_2 flow rate the cost would be US$ 1100 €/(kg/h). The cost 1200 €/(kg/h) was used here, together with fixed annual O&M cost 40 €/(kg/h). The MEA-based PCC process also has variable costs arising from e.g. solvent costs, and they were set to 8 € per captured CO_2 tonne.

The MEA-based PCC process also consumes electricity and low-pressure steam. Different results for these quantities have been obtained in different simulations [19], [20]. Here the values shown in Table 4 are used.

CO_2 was assumed to be stored in the liquid phase. The choice of pressure and temperature of the stored CO2 depends on the storage solution. Lower temperature lowers the material requirements for the storage tanks [21]. Kujanpää et al [21] estimated the investment cost of storage tanks to be 950 – 2700 €/m^3, with the average estimate being 1830 €/m^3.

An alternative method to acquire CO_2 is direct air capture (DAC), where CO_2 is extracted from ambient air. Several different technologies have been developed for this purpose [22]. The benefit is the high purity of the product as well as possibility to decouple the CO_2 capture spatially and temporally from power plant operation. Schmidt et al [23] estimate that the cost of large (20 tCO_2/h) plant based on temperature swing adsorption could be 90 million euros. Considering that the power-to-gas plant consumes 0.12 kg of CO_2 for each kWh consumed by the electrolysis, DAC would add 540 €/kW$_e$ to the total plant cost (assuming full capacity of the capture plant). Here the power unit refers to the input power of the electrolysis. The DAC plant also consumes a considerable amount of energy. The heat consumption 2 MWh/tCO_2 and electricity consumption 0.7 MWh/tCO_2 was used [23]. Annual O&M cost was assumed to be 2 % of the investment as shown in Table 4.

After capture and intermediate storage, the subsequent pathway for the CO_2 was either utilization in the methanation process or shipping to a permanent geological storage. Biomass firing with carbon capture and storage can even produce negative emissions, i.e. removal of CO_2 from the atmosphere on life cycle basis [24]. However, the EU emission trading regulations [25] do not accept subtracting the captured CO_2 from the plant emissions with biomass-fired plants. In this work the subtraction was allowed and consequently the consumer of the SNG is then responsible for the emissions and this must be considered in the SNG price. The export and storage cost of CO_2 was set to 15 €/t.

Table 4.Economic and technical parameters of the capture plants.

Parameter	MEA-based PCC	DAC	Unit
Capital cost	1200	4500	€/(kg$_{CO2}$/h)
O&M fixed cost	40	90	€/(kg$_{CO2}$/h)/a
O&M variable cost	8	0	€/t$_{CO2}$
Power consumption	0.18	0.7	MWh/t$_{CO2}$
Low-pressure steam consumption	0.55	2.0	MWh/t$_{CO2}$
Capture efficiency	90	–	%

2.8. District heat demand

District heat demand of the city was simulated based on hourly measurements of year 2011 of air temperature and global horizontal irradiation by the Finnish Meteorological Institute. A separate time series, based on a sample of measured consumers, was used for domestic hot water energy demand. The model was validated with measurement data from a Finnish city whose population was about 100,000. The annual measured demand of heat was 2.0 TWh.

2.9. Power and fuel prices

Power prices for the area were simulated separately. The results of marginal cost of electricity obtained by Ikäheimo and Kiviluoma [26] were exploited. Marginal cost of electricity can be considered as the electricity price in a competitive market. The studied region included the Nordic countries, the Baltic countries, Germany and Poland. The setting in the simulation was year 2050 with more than 100 % renewable electricity generation (mostly wind power) relative to electricity consumption, with part of the electrical energy going into SNG and district heat production by heat pumps. The average price was 39 €/MWh.

The transmission and distribution cost of electricity for heat pumps and the power-to-gas plant was assumed to be 5 €/MWh, which is a reasonable value for a Finnish case.

Wood price was set to 25 €/MWh and peat price to 14 €/MWh.

2.10. Taxes and economic assumptions

The price of the CO_2 emission allowance was set to 60 €/t. Electricity tax for heat pumps and P2G plants was set to 3.4 €/MWh, which is a reasonable value for a Finnish case. Capital costs were annualized assuming a lifetime of 20 years in the base case with 30 and 40 years also simulated for plants other than P2G. Longer lifetime is not justified for P2G plants because of the fast degradation of electrolyzers. Interest rate of 7 % was used.

3. Results

Power-to-gas plants reached high annual operating time when they were present in the system. Table 5 shows the summary of optimal system operation when the P2G investment cost was 1000 €/kW and SNG price 80 €/MWh and the CHP capacity was set exogenously to 450 MW_{fuel}. The CHP plant supplies by far the largest share of heat in the city. The optimized capacity of power-to-gas was 585 MW_e. The plant reached an annual full-load operating time of 5400 hours and supplies about one fourth of all heat on the annual level. Heat pumps were also important producers in winter, followed by biomass-fired district heating boilers, which are more important during high load. Gas boilers are solely used during the highest load peaks (Fig 2). Heat storages appear in the system with much higher capacity than is typical today.

Fig 3. shows the breakdown of costs and income flows for the power-to-gas plant. We may note, however, that it is difficult to make such analysis because P2G is linked to the rest of the system via heat and CO_2 flows. In Fig 3. the value of heat output was calculated using the marginal value of district heat. CO_2 supply is not included in the cost figures because the post combustion capture is also used for CCS. The total systemic annual costs in this case were 3 M€ lower in the case P2G was present compared to the case with no P2G.

Income from oxygen is not included in the figure. If 168 kg oxygen per MWh of input electricity is produced, and the value of oxygen were 30 €/t, it would create an additional annual income of 16 million euro, less the cost of equipment for handling oxygen.

Table 5. Resulting capacities and production when P2G investment cost was 1000 €/kW and SNG price 80 €/MWh.

Conversion technology	**Capacity**	**Annual production**
CFB CHP	450 MW_{fuel}	1.2 TWh_{th}
heat pump	102 MW_{th}	30 GWh_{th}
power-to-gas	585 MW_e	1.7 TWh_{SNG}
solar thermal	18 MW_{th}	6.1 GWh_{th}
biomass boiler	214 MW_{th}	230 GWh_{th}
gas boiler	119 MW_{th}	35 GWh_{th}
heat storages	6240 MWh_{th}	350 GWh_{th}
CO_2 storage	7650 t	360,000 t

Solar thermal district heating was not found economically feasible from the system point of view. However, consumers may invest into decentralized plants, which may be profitable when the plants compete against the retail price of heat. Thus a collector area 30,000 m^2 (about 18 MW_{th}) was exogenously set for solar district heating. The presence of this solar district heating plant had little effect on the results. Availability of large amount of waste heat from the operation of P2G further reduced the profitability of solar district heating.

The threshold price of SNG above which the P2G investment is economically feasible from the system point of view, when the PCC investment is also considered, varied between 67–85 €/MWh_{LHV} depending on the P2G investment cost (Fig 4).

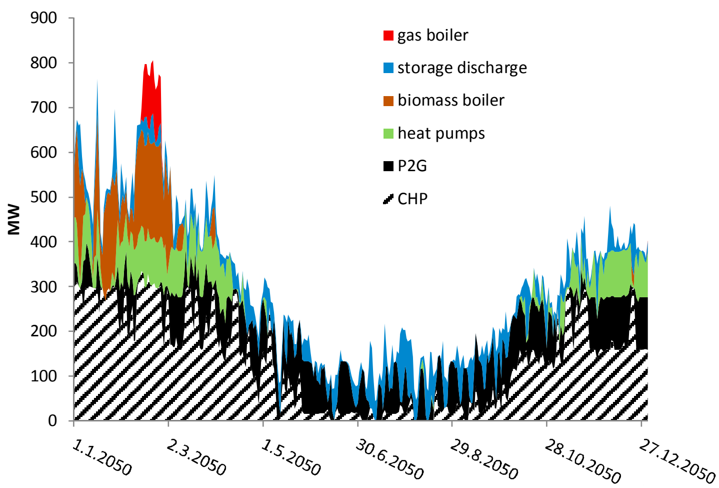

Fig 2.Daily averages of optimized heat production schedules for different plants in case of 1000 €/kW investment cost of P2G and 80 €/MWh SNG price. Daily averages of solar district heating was too small to show in the graph.

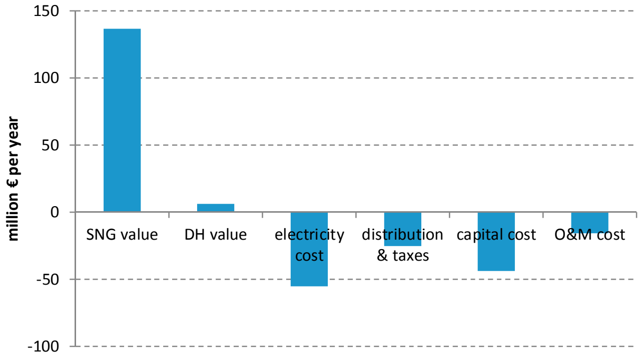

Fig 3. Breakdown of annual costs and income flows of the P2G plant in the case of 1000 €/kW investment cost of P2G and 80 €/MWh SNG price.

The optimal PCC capacity turned out to be about 55 tonnes CO_2 per hour (CHP plant flue gas contained maximum 172 t_{CO2}/h) and did not depend much on the P2G capacity when P2G was present. Annually 51 % of the plant emissions were captured by the PCC plant when the P2G investment cost was 1000 €/kW and SNG price 80 €/MWh. The decision to invest into PCC depended on the presence of P2G. In principle, it was also possible to run the plant as CCS plant. Fig 5, however, shows that when SNG price falls below the threshold of P2G profitability, no investment is made into PCC. The resulting export amounts were so small that shipping them would not be economical. The export cost of CO_2 had little effect on optimal P2G capacity or operation when it was varied between 15–25 €/t. Thus running an isolated system where all the captured CO_2 is used for SNG production would also be feasible with the same cost parameters.

The assumption above was that CHP plant was already present in the system and none of its costs need to be attributed to the P2G investment. An alternative system would be one based only on district heating boilers and heat pumps. This case was also simulated, assuming that the possible P2G plant needs to use DAC for CO_2 supply. P2G was not economically feasible even at the highest simulated SNG price 90 €/MWh in this case. The total annual costs of the system were 9 M€ (10 %) lower than in the CHP case, reflecting the fact that the employed electricity price was too low for long-term CHP profitability. However, the chosen lifetime and interest rate influence the result to a great degree because of the high capital cost of the CHP plant. Further simulations were performed with lifetimes of the CHP plant, boilers and heat pump increased to 30 or 40 years. Assuming 30 years lifetime, the total cost of the alternative systems was roughly the same, and with 40 years lifetime, the total cost of the system based on CHP was 6 M€ (8 %) lower.

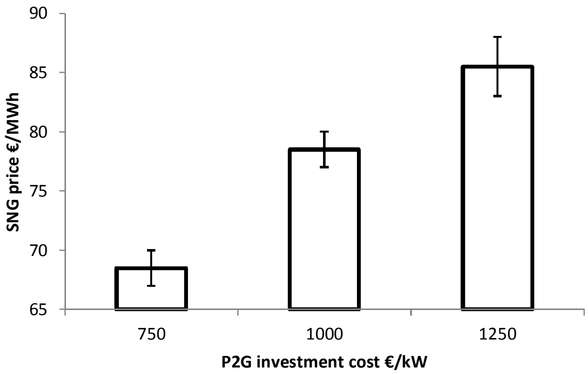

Fig 4. Threshold price of SNG above which P2G was profitable. The error bars indicate the uncertainty in the limited number of simulations.

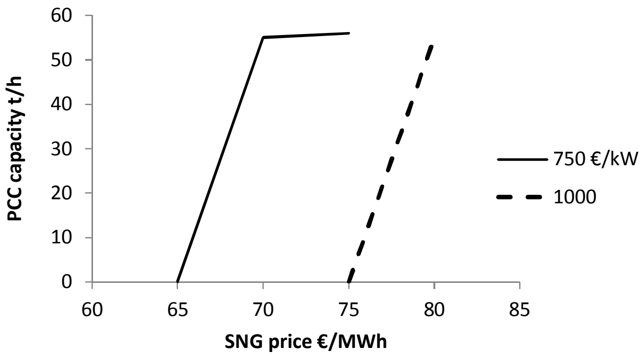

Fig 5. Optimized post-combustion capture plant capacity as function of SNG price and P2G investment cost.

4. Conclusions

We find that in a bio-CHP dominated district heating system P2G where CO_2 is supplied by post-combustion capture plant can be profitable from the system point of view at price levels of SNG 67–85 €/MWh depending on the investment cost of the P2G plant. The product SNG was by far the largest income source, with heat sales contributing only a minor part. Electricity cost and capital cost were almost equal Electricity distribution costs and electricity taxes were also important if they are determined according to current Finnish tariffs and regulations. Oxygen was not included in the analysis but it could bring a significant amount of income if a buyer for the oxygen is found. It is also possible to increase profitability of P2G even further by offering demand response (DR) which goes beyond the hourly resolution, i.e., system reserves. However, it is difficult to estimate the income which is available from system reserves market in the future.

P2G has various effects on the system operation. P2G operates largely according to electricity price and as result of the P2G operation during summer there can be an oversupply of heat. In the simulation solar thermal district heating plant was shut down during the oversupply period, and the investment into solar district heating was not beneficial. P2G also needs CO_2 which drives the CHP plant away from its normal optimum. We note especially the increased summertime operation of CHP. These effects of course depend on the size of the P2G plant relative to the system. In this work the size of the plant was optimized from the local system point of view, assuming inelastic power prices.

CCS was an option for the CHP plant but it was practically not utilized. Thus it would be economically feasible to run the system as a pure CCU system where all the captured CO_2 is used for methanation.

With our cost and electricity price assumptions a system where only district heat boilers and heat pumps were generating heat was more cost efficient than the system based on CHP. Lower cost of capital or lower fuel costs could change the situation. P2G based on DAC was not competitive in any of the simulated cases.

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