Towards the Optimal Development of Low-Carbon Community Energy Systems

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ABSTRACT

More and more communities and cities are moving toward low-carbon and sustainable development using smart grid concepts. In China, the development of numerous newly planned communities presents an opportunity to incorporate sustainable energy systems. What the opportunity requires are the scientific tools necessary to deploy the energy technologies that are most suited to a particular site. This paper focuses on optimizing the planning and operation of low-carbon district energy systems that incorporate solar photovoltaics (PV), thermal energy storage, and combined heat and power plants. We developed an optimization tool that is modeled as a multi-objective, mixed integer linear programming problem regarding meeting a community's heating, cooling, and electricity needs. One objective in solving the problem is to minimize the installation and operating costs for low-carbon energy technologies, which in turn will minimize the cost attributed to carbon emissions associated with the community's energy production. We also consider the potential for profit from selling surplus electricity and heating energy outside of the community. The distribution network is modeled to account for losses through the pipelines that deliver thermal energy. The model determines the optimal capacity and operation of each low-carbon option within the optimization time horizon. The model is being tested on an eco-city project in China.

This model developed for this study could be used as a district energy system planning tool for developers, urban planners, practitioners, or energy mangers seeking to meet a community's energy needs. Alternatively, the optimization tool could be used to identify the optimal operation of established thermal energy systems.

Introduction

China and the United States are the two largest carbon-emitting countries in the world. Climate change circumstances call for developing low-carbon communities (DECC report, 2015). Renewable energy resources such as solar panels, solar thermal collectors, and wind turbines play an important role in reducing a community's carbon emissions. The challenges surrounding development of low-carbon communities include choosing the optimal low-carbon technologies; measuring the associated savings in carbon emissions; evaluating the environmental, social, and economic benefits; and providing for scalability of test applications.

At the community level, low-carbon energy technologies typically consist of PV, solar thermal systems, air or ground source heat pumps, a biomass-based district heating system, wind turbines, heaters, and boilers.

Optimal development of a community-scale low-carbon energy system incorporates lease-cost strategies to integrate renewable energy resources and reduce carbon emissions. The optimization model evaluates the potential for reducing carbon emissions based on the low-carbon technologies incorporated in the community system design. The goal is to find out the most economic decisions on which technologies will be chosen and at what capacity they should be installed at the planning stage. Requirements include hourly energy balance, power and thermal energy generation limits for each technology, capacity limit, etc.. For electricity as well as heating and cooling storage systems, it may also need to take into account the temporal relationship for charging and discharging behavior between consequent time periods. Meanwhile, the consideration of power and thermal energy in the same district energy system makes it more difficult to model the correlation between power and thermal energy balance. The techniques for developing low-carbon communities potentially could be applied to larger urban developments.

Our model of a low-carbon energy system for a community considers a combination of low-carbon technologies such as PV, CHP, boiler, chiller, and heat tank. The system must meet the community's energy demands for electricity, heating, and cooling. Adding heat tanks to a system is found to increase CO_2 emissions but decrease the total cost. The pipeline network produces the highest CO_2 emissions in the energy system, but the system's total cost is lower than in cases that do not consider the pipeline.

Modeling a district energy system

We developed an optimization model for selecting energy technologies to be used in planning and operating an optimal district energy system (Mehleri et. al 2012). The model also determines the periodic energy output and production of carbon dioxide (CO_2). Within the stipulated time horizon, the optimization problem comprises two stages. In the planning stage, the object of the problem is to select the energy technologies to be installed. Based on the technologies selected, the installed system capacity is determined. The operating status must be defined to optimize the operating stage. Control variables include, but are not limited to, the charging and discharging status of any energy storage system, electricity exchange between building clusters and the electric grid, and ON or OFF status of the combined heat and power (CHP) plant. The periodic energy output from each selected technology is determined under operating conditions.

The general optimization problems include linear programming (LP), mixed integer linear programming (MILP), nonlinear programming (NLP), etc. Basically, the linear programming problem does not consider any nonlinear relationship in the optimization model. Since we do not have any nonlinear constraints, our problem can be modeled as a linear problem. Moreover, it involves both integer and continuous variables, therefore this problem can be further modeled as a mixed integer linear programming problem.

A. Objective function

The objective function consists of two parts, f_{cost} indicates both installation and operation cost for the planning of the community energy system, while $f_{CarbTax}$ is the carbon emission tax charged due to the CO2 emission from energy technologies. These two parts are competing with each other. While reducing the total cost, the carbon emission tax would increase; if the final goal is to reduce carbon emission, then the total cost will increase accordingly. Therefore, it is a multi-objective function. A complicated way is to consider a different weight on each part of the objective function. In the paper, we simply take both equally, no emphasis in either of them.

$$f_{TOTAL} = f_{cost} + f_{CarbTax}$$

Cost function

As shown, the basic goal of the optimization problem is to minimize overall annualized investment cost and annual operating cost of the system while maximizing the profit from selling surplus electricity and heating energy outside the district system:

$$min f_{cost} = f_{INV} + f_{OP} + f_{MTN} + f_{PUR}^{GRID} - f_{SAL}^{GRID}$$

Where f_{INV} is the investment cost; f_{OP} is operation cost; f_{MTN} is maintenance cost; f_{PUR}^{GRID} is purchase cost for electricity; f_{SAL}^{GRID} is sale profit out of electricity.

Total investment costs are calculated for PV units, solar thermal sources, electric and natural gas-fired boilers, CHP units, and heat and electric energy storage, as shown below:

$$C_{INV} = (C_{INV}^{PV} + C_{INV}^{ST}) + \left(C_{INV}^{ELEboil} + C_{INV}^{NGboil}\right) + (C_{INV}^{HST} + C_{INV}^{EST}) + \left(C_{INV}^{ABSchill} + C_{INV}^{ELEchill} + C_{INV}^{NGchill}\right) + C_{INV}^{HP} + C_{INV}^{CHP}$$

Where C_{INV}^{PV} means investment cost of PV system; C_{INV}^{ST} means investment cost of solar thermal collectors; $C_{INV}^{ELEboil}$ means investment cost for electric boiler; C_{INV}^{NGboil} means investment cost for natural gas boiler; C_{INV}^{HST} means investment cost for heating storage system; C_{INV}^{EST} means investment cost for electricity storage system; $C_{INV}^{ABSchill}$ means investment cost for absorption chiller; $C_{INV}^{ELEchill}$ means investment cost for electric chiller; $C_{INV}^{NGchill}$ means investment cost for natural gas chiller; C_{INV}^{HP} means investment cost for heat pump; C_{INV}^{CHP} means investment cost for CHP plants.

By stipulating the interest rate, we can annualize total investment costs and compare those to operating costs. To obtain the annualized capital cost, we apply the capital recovery factor (CRF) for each type of equipment, calculated as:

$$CRF = \frac{r \cdot (1+r)^n}{(1+r)^n - 1}$$

Where *r* is an interest rate; *n* is the number of annuities received.

The general method for calculating the investment cost for discrete technologies, such as CHP, is shown as:

$$C_{INV}^{disc} = \sum_{k} N_k^{disc} \cdot CRF_k^{disc} \cdot C_k^{disc} \cdot g_k^{disc} \cdot X_k^{disc}$$

Where k is the type of the discrete technology, g_k^{disc} is the capacity of type k; X_k^{disc} is the decision variable of type k; C_k^{disc} is the installation cost of type k; N_k^{disc} is the number of installation for type k.

For continuous technologies with installation capacity within a continuous range such as PV or solar thermal collector, the investment cost includes both fixed and variable costs. Although the fixed cost pertains to the operation of the system, it depends on the initial investment. Alternatively, the fixed cost can be determined by the rated capacity of the continuous technology:

$$C_{INV}^{cont} = CRF_{cont} \cdot (X_{cont} \cdot C_{fix}^{cont} + Cp_{rat}^{cont} \cdot C_{var}^{cont})$$

The cost for operating back-up boilers and the CHP units (Best et al. 2014), as well as natural gas-fired chillers, depends on the natural gas consumption:

$$C_{OP}^{GAS} = C_{OP}^{NGboil} + C_{OP}^{CHP} + C_{OP}^{NGchill}$$

Where C_{OP}^{NGboil} is the operation cost of natural gas boiler; C_{OP}^{CHP} is the operation cost of CHP plants; $C_{OP}^{NGchill}$ is the operation cost of natural gas chiller.

Maintenance costs for continuous technologies are calculated by:

$$C_{mtn}^{cont} = \sum_{m} \sum_{d} \sum_{h} N_{m,d} \cdot NG_{m,d,h}^{cont} \cdot c_{mtn}^{cont}$$

Where m is the month index; d is the date index; h is the hour index; $N_{m,d}$ is the total number of hours in the day d of month m.

Maintenance costs for discrete technologies are calculated as the sum of the maintenance cost for each technology type k.

$$C_{mtn}^{disc} = \sum_{m} \sum_{d} \sum_{h} \sum_{k} N_{m,d} \cdot NG_{m,d,h,k}^{CHP} \cdot c_{mtn}^{disc}$$

Where $NG_{m,d,h,k}^{CHP}$ is the natural gas consumption of CHP plants.

Carbon emissions

The pollutants emitted by a district energy system can cause many environmental problems, such as air pollution, global warming, acidification, ozone depletion, and forest destruction. SO_x, NO_x, and other acid gas emissions produced by burning fuels increase the acidity of rain, leading to acidification of lakes and soil. The emission of SO_x and NO_x resulting from human activities produce negative effects throughout a region. Cumulative carbon emissions, which reflect the carbon content of the purchased electricity or natural gas used in a boiler, CHP, or natural gas-fired absorption chiller, is calculated by multiplying the quantity of consumed electricity and gas by their CO_2 emission intensities (Bakken et al 2008). The CO_2

produced by electricity generation from a CHP is accounted for through the amount of natural gas used in the cogeneration unit:

$$Q_{CO2} = \sum_{m}\sum_{d}\sum_{h}[N_{m,d} \cdot CI_{ele} \cdot P_{m,d,h}^{GRID\_pur} + N_{m,d} \cdot CI_{gas} \cdot \left(NG_{m,d,h}^{NGboil} + NG_{m,d,h}^{CHP} + NG_{m,d,h}^{NGchill}\right)]$$

Where Q_{CO2} is the cumulative carbon emission from electricity and thermal energy generation; CI_{ele} is the amount of carbon emission from electricity generation; $P_{m,d,h}^{GRID\_pur}$ is the amount of electricity purchased from the power grid; CI_{gas} is the carbon emission from energy generated by natural gas; $NG_{m,d,h}^{NGboil}$ is the amount of natural gas consumed by natural gas boiler; $NG_{m,d,h}^{CHP}$ is the amount of natural gas consumed by CHP plants; $NG_{m,d,h}^{NGchill}$ is the amount of natural gas consumed by natural gas chiller.

The cost associated with carbon emissions is calculated as the cumulative carbon emission multiplied by the carbon tax rate:

$$minf_{CarbTax} = CT \cdot Q_{CO2}$$

Where *CT* is the carbon tax rate.

B. Energy balance

A community energy system must fulfill customers' requirements for both electricity and thermal energy. Electricity loads can be met by PV arrays, CHP units, electric storage, or purchases from the grid. Excess electricity produced by the district energy system is considered income.

$$D_{m,d,h}^{ele\_only} + P_{m,d,h}^{GRID\_sal} + P_{m,d,h}^{ELEchill} + P_{m,d,h}^{HPS} + P_{m,d,h}^{ELEboil} = P_{m,d,h}^{GRID\_pur} + P_{m,d,h}^{PV} + \sum_{k=1}^{T_{CHP}}\sum_{i=1}^{N_k^{CHP}} P_{m,d,h,k,i}^{CHP}, \forall m, d, h$$

Where $D_{m,d,h}^{ele\_only}$ is the electricity demand for the community customers; $P_{m,d,h}^{GRID\_sal}$ is the electricity sold outside the community energy system; $P_{m,d,h}^{ELEchill}$ is the electricity consumption by electric chiller in the community energy system; $P_{m,d,h}^{HPS}$ is the electricity consumption for heat pump; $P_{m,d,h}^{ELEboil}$ is the electricity consumption by electric boiler; $P_{m,d,h}^{GRID\_pur}$ is the electricity purchased from outside of the community; $P_{m,d,h}^{PV}$ is the electricity generation from PV panels within the community energy system; $P_{m,d,h,k,i}^{CHP}$ is the electricity generation provided by CHP plants.

The heating load in a district energy system refers primarily to space heating, air conditioning, water heating, ventilation, and process heat. Space heating, ventilation, and air conditioning represent seasonal heating loads, whereas water heating and process heating are year-round heating loads. In our model, the seasonal heat load includes space heating only, and the year-round heat load refers to water heating.

$$H_{m,d,h}^{BLDG\_heat} = H_{m,d,h}^{SH} + H_{m,d,h}^{WH}$$

Where $H_{m,d,h}^{BLDG\_heat}$ is the heating demand for the community customers; $H_{m,d,h}^{SH}$ is the heating demand for space; $H_{m,d,h}^{WH}$ is water heating demand.

Heat loads can be satisfied by boilers, CHP units, solar thermal, a natural gas chiller, heat storage for space heating, or water heating:

$$H_{m,d,h}^{BLDG\_heat} + H_{m,d,h}^{HST\_sto} + H_{m,d,h}^{PIPE\_loss} + H_{m,d,h}^{ABSchill} = H_{m,d,h}^{INDS} + H_{m,d,h}^{HP} + H_{m,d,h}^{ELEboil} + H_{m,d,h}^{NGboil} + \sum_{k=1}^{T_{CHP}} \sum_{i=1}^{N_k^{CHP}} H_{m,d,h,k,i}^{CHP} + H_{m,d,h}^{ST} + H_{m,d,h}^{HST\_from}, \forall m, d, h$$

Where $H_{m,d,h}^{BLDG\_heat}$ is heating demand of the community customers; $H_{m,d,h}^{HST\_sto}$ is heating for storage; $H_{m,d,h}^{PIPE\_loss}$ is heating loss; $H_{m,d,h}^{ABSchill}$ is heating input for absorption chiller; $H_{m,d,h}^{INDS}$ is heating purchased from the industry waste heat; $H_{m,d,h}^{HP}$ is heating generation from heat pump; $H_{m,d,h}^{ELEboil}$ is heating generation from electric boiler; $H_{m,d,h}^{NGboil}$ is heating from natural gas boiler; $H_{m,d,h,k,i}^{CHP}$ is heating generation from CHP plants; $H_{m,d,h}^{ST}$ is heating generation from solar thermal system; $H_{m,d,h}^{HST\_from}$ is heating output from heat storage system.

The cooling load is supplied by an electric chiller, absorption chiller, or natural gas chiller:

$$Q_{m,d,h}^{BLDG\_cool} + Q_{m,d,h}^{PIPE\_loss} = Q_{m,d,h}^{HP} + Q_{m,d,h}^{ELEchill} + Q_{m,d,h}^{ABSchill} + Q_{m,d,h}^{NGchill}$$

Where $Q_{m,d,h}^{BLDG\_cool}$ is the cooling demand of the community customers; $Q_{m,d,h}^{PIPE\_loss}$ is the cooling pipeline loss; $Q_{m,d,h}^{HP}$ is the cooling output from heat pump; $Q_{m,d,h}^{ELEchill}$ is cooling generation of electric chiller; $Q_{m,d,h}^{ABSchill}$ is cooling from absorption chiller; $Q_{m,d,h}^{NGchill}$ is cooling from natural gas chiller.

Model of pipeline network

This section describes the model we used for evaluating the energy associated with losses through the energy system's network of delivery pipes (Vesterlund et al. 2013).

A. Grid integration

The model must account for two aspects of the electricity grid.

1. The cost for purchasing electricity from the grid:

$$C_{PUR}^{GRID} = \sum_m \sum_d \sum_h N_{m,d,h} \cdot c_{m,d,h}^{ELE\_pur} \cdot P_{m,d,h}^{GRID\_pur}$$

2. The profit from selling electricity to the grid:

$$C_{SAL}^{GRID} = \sum_m \sum_d \sum_h N_{m,d} \cdot c_{m,d,h}^{ELE\_sal} \cdot P_{m,d,h}^{GRID\_sal}$$

Electricity can move in two directions between the power distribution network and the district energy system: it may be purchased from the power distribution network, $E_{m,d,h}^{GRID\_pur}$, or fed back to the distribution network in the amount of $E_{m,d,h}^{GRID\_sal}$. Only one state can exist at any given time, however, as indicated by the status variables $X_{m,d,h}^{GRID\_pur}$ and $X_{m,d,h}^{GRID\_sal}$. The upperbound limit for electricity exchanged between the distribution network and the district energy system usually is set at an extremely high value:

$$0 \leq P_{m,d,h}^{GRID\_pur} \leq X_{m,d,h}^{GRID\_pur} \cdot P_{max}^{GRID\_pur}$$

$$0 \leq P_{m,d,h}^{GRID\_sal} \leq X_{m,d,h}^{GRID\_sal} \cdot P_{max}^{GRID\_sal}$$

$$0 \leq X_{max}^{GRID\_pur} + X_{m,d,h}^{GRID\_sal} \leq 1$$

$E_{max}^{GRID\_sal}$ can be selected to represent the largest available CHP capacity plus the maximum amount of electrical energy that can be produced by the largest possible PV installation in the district energy system within one hour throughout a year.

B. Pipeline network

Thermal loss occurs when thermal energy is distributed through pipelines (Bohm et al. 2000). For simplicity, our model considers pre-insulated single-pipe distribution systems. The pipeline network is modeled as consisting of main pipe sections and secondary heating/cooling distribution lines (Bohm et al. 2006). More than one building may be connected directly or indirectly to each main section. Secondary lines, however, serve only to connect individual buildings with the primary network, so that only one building is linked to a given secondary branch. When a building is connected directly with the main section, the length of the associated secondary branch is zero.

The total heat energy lost in a pipeline network is almost constant during the heating season if the supply temperature is constant (the return temperature has a smaller effect). It is also proportional to the length of the heating season.

Thermal losses through pipelines can be calculated in two ways (Zager et al. 2011). The load-following method calculates the loss based on the thermal energy delivered by the pipeline network. Using this method, the loss varies through time as the thermal load varies throughout the year. This method assumes that the heat loss in pipelines is proportional to the heating load distributed through the primary and secondary lines. The cooling loss is modeled in the same way:

$$H_{m,d,h}^{PIPE\_loss} = \sum_l (1 - \eta_{heat,l}^{PIPE}) \cdot H_{l,m,d,h}^{BLDG\_heat} + \sum_n (1 - \eta_{heat,n}^{PIPE}) \cdot H_{n,m,d,h}^{BLDG\_heat}$$

$$Q_{m,d,h}^{PIPE\_loss} = \sum_l (1 - \eta_{cool,l}^{PIPE}) \cdot Q_{l,m,d,h}^{BLDG\_cool} + \sum_n (1 - \eta_{cool,l}^{PIPE}) \cdot Q_{n,m,d,h}^{BLDG\_cool}$$

The length-following method of calculating thermal losses through a network assumes that the losses depend on the distance the energy resource travels. The gamma coefficient in the following two equations indicates that the pipeline losses are calculated based on the length of

the pipeline that delivers the thermal energy required by customers. Using this method, the loss remains the same no matter how greatly the amount of delivered thermal energy changes through time:

$$H_{m,d,h}^{PIPE\_loss} = \gamma_{heat}^{PIPE} \cdot (\sum_l L_l^{PIPE} + \sum_n L_n^{PIPE})$$

$$Q_{m,d,h}^{PIPE\_loss} = \gamma_{cool}^{PIPE} \cdot (\sum_l L_l^{PIPE} + \sum_n L_n^{PIPE})$$

Generally speaking, the two methods can be applied based on the availability of data for system planning. It can be seen that the first loss calculation method is more practical since it takes into account the loss impact for both heating and cooling energy. While for the second method, all thermal energy is treated in the same way. Therefore, in the paper, the first method is considered for the calculation of heating and cooling energy in the pipeline network.

Community case studies

To apply our model, we built case studies for community systems that include the energy technologies of PV, CHP, heat tank, absorption chiller, electric chiller, natural gas boiler, natural gas chiller, and electric boiler. Electricity purchases are not allowed. The maximum loads are 63, 53, and 312 MW for electricity, heating, and cooling, respectively. Figure 1 shows the energy demand associated with each load. The figure indicates that the highest cooling load is much greater than either the electricity or heating load. The period covered is 12 months, with a sample of 2 typical days each month. We do not account for the impact of length of weekday and weekend day on the total cost. A one-hour time step is used in the optimization problem. Therefore we will have totally 576 time periods for a one-year planning horizon.

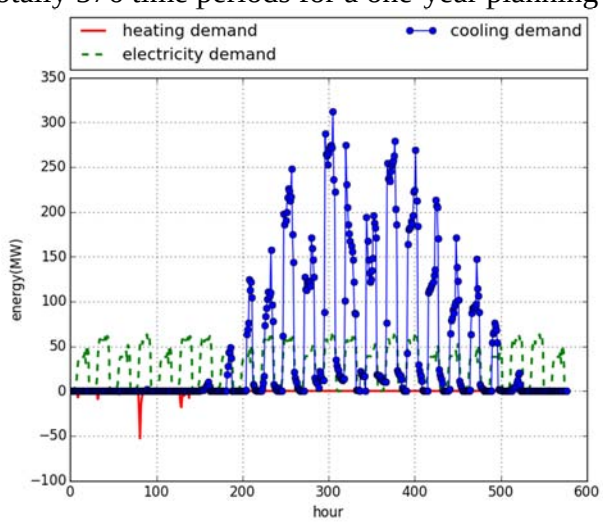

Figure 1. Energy demand

Figure 2 shows the distribution of cooling demand used in the case studies. Figure 3 shows the distribution of heating demand used in the studies.

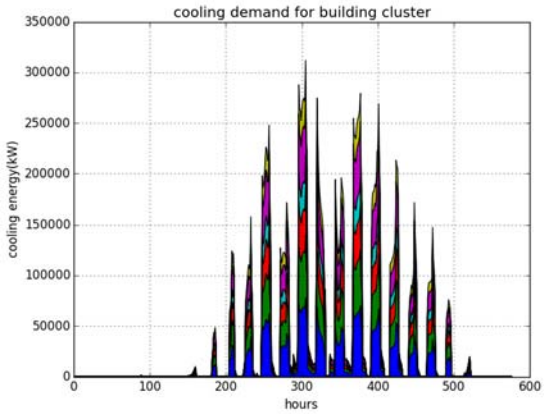

Figure 2. Distribution of cooling demand

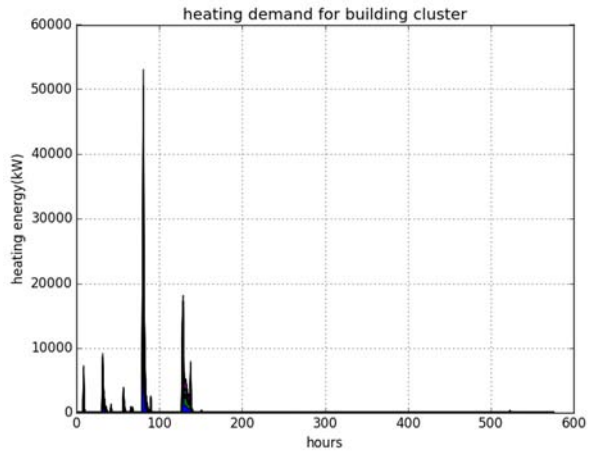

Figure 3. Distribution of heating demand

We developed three basic cases in order to examine the impact of CO_2 emissions and pipeline network on the optimal planning and operation of district heating and cooling systems. In Table 1, case 1 considers neither CO_2 emissions nor pipeline network. In case 2, CO_2 emissions are considered but the pipeline network is ignored. Case 3 considers both CO_2 emissions and the pipeline network. We based three additional cases on the first three. Case 4 is based on case 1, except electricity purchases are allowed. Case 5 is based on case 2, but again electricity purchases are allowed. Case 6 is based on case 2, but no heat tank is considered.

Table 1 Case design

Cases	Description
1	considers neither CO_2 emissions nor pipeline network
2	CO_2 emissions are considered but the pipeline network is ignored
3	considers both CO_2 emissions and the pipeline network
4	based on case 1, and electricity purchases are allowed
5	based on case 2, and electricity purchases are allowed
6	based on case 2, but no heat tank is considered

As shown in Table 2, the optimization model indicates that an absorption chiller capacity is selected at 177 MW. The installed capacity of a natural gas boiler is 80 MW. The capacity of a natural gas chiller is 80 MW. A heat tank's installed capacity is 66 MWh. In the first three cases the installed capacity of an electric chiller is 150 MW. In both cases 1 and 2, the installed area of PV is 0.7 km^2; in case 3, the area of PV is reduced to 0.3 km^2. Cases 1 through 3 consider CHPs having four capacities—20, 10, 15, and 23 MW. In cases 4 and 5, only the 23 MW CHP is selected because much of the needed electricity is purchased from the power grid.

Table 2 Capacity selection

Cases	Technology	Capacity
1-5	absorption chiller	177 MW
	natural gas boiler	80 MW
	natural gas chiller	80 MW
	heat tank	66 MW
1	electric chiller	150 MW
	PV	0.7 km^2
	CHP	10,15, 20,23 MW
2	electric chiller	150 MW
	PV	0.7 km^2
	CHP	10,15, 20,23 MW
3	electric chiller	150 MW
	PV	0.3 km^2
	CHP	10,15, 20,23 MW
4	CHP	23 MW
5	CHP	23 MW

The total cost for case 2 is the highest among the three basic cases. Case 2 has a higher total cost than case 1 because case 2 accounts for CO_2 emissions and the CO_2 tax. When the cost of CO_2 emissions is considered in both cases 2 and 5, the total cost is higher than the cost of cases 1 and 4. Because electricity purchases are allowed in cases 4 and 5, their total cost is much lower than the cost of cases 1 and 2. Figure 4 shows the costs associated with each of the six cases.

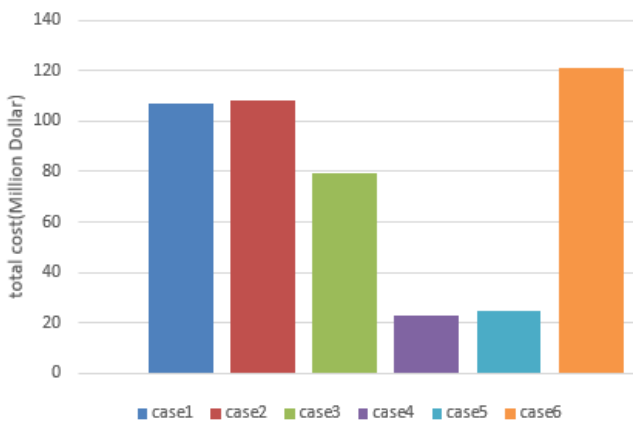

Figure 4. Cost comparison for six cases

Sample model results are presented in Figure 5 for the cooling balance, Figure 6 for the electricity balance, and Figure 7 for the heating balance under case 2, which accounts for CO_2 emissions but ignores the effects of the pipeline network. Similar figures can be produced for all cases.

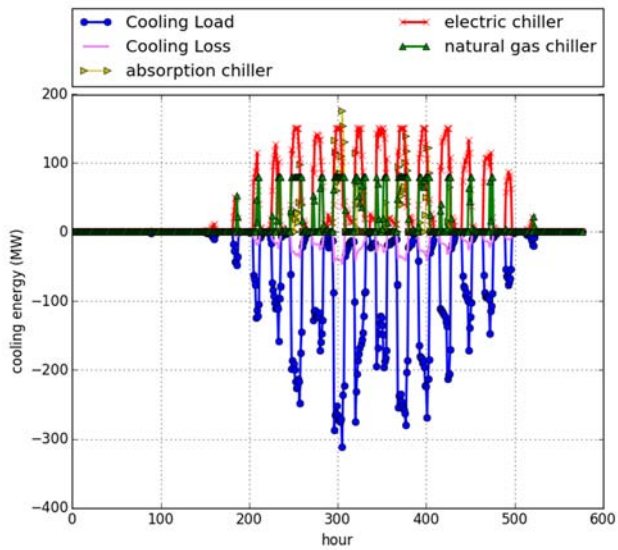

Figure 5. Cooling balance for case 2

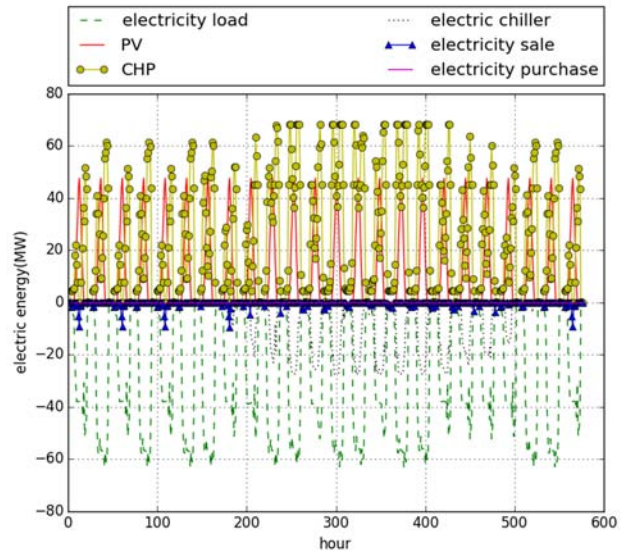

Figure 6. Electricity balance for case 2

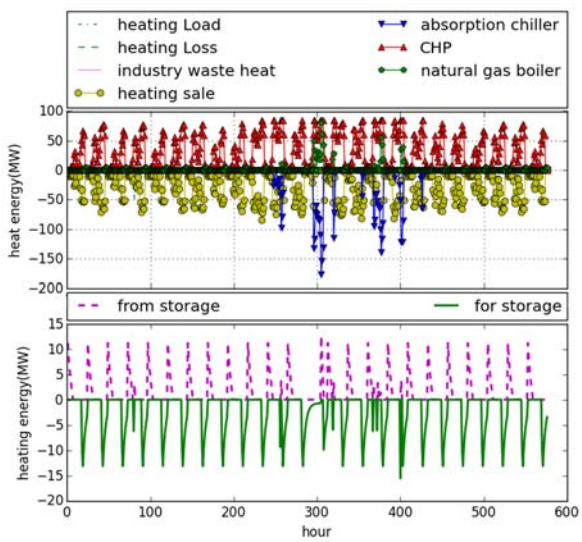

Figure 7. Heating balance for case 2

A. Impact of CO_2 emissions

Because the optimization problem does not consider an entire years' worth of data, total CO_2 emissions represent those for only two days per month throughout the year. The model assumes that the CO_2 emissions from electricity generation and natural gas delivery are 0.088 $kgCO_2/kWh$ and 0.231 $kgCO_2/kWh$, respectively. The tax on CO_2 emissions is set to 1.023 $\$/kgCO_2$ for electricity and 0.13 $\$/kgCO_2$ for natural gas. No CO_2 is considered for the PV system.

CO_2 emissions are reduced in response to the emission tax. The CO_2 emission is 23,412 kg less in case 2 than in case 1, for example, and 903,587 kg less in case 5 than in case 4. Case 5, which assumes both the CO_2 emission tax and the ability to purchase electricity, results in the

lowest CO_2 emissions. Case 3, on the other hand, which considers losses through the pipeline network, causes the highest CO_2 emissions.

Figure 8 compares the CO_2 emissions associated with each case.

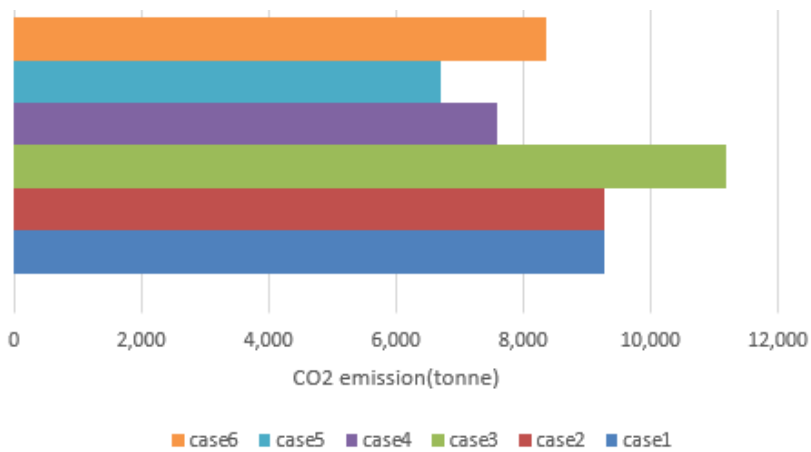

Figure 8. Comparison of CO_2 emissions for the six cases

CO_2 emissions from the CHPs are highest in case 3. Although four types of CHP are selected for cases 1 through 3, total electricity output from the CHP is much greater in case 3 than in cases 1 or 2 because the area of installed PV is reduced in case 3. Cases 4 and 5, which incorporate electricity purchases, show greatly reduced CO_2 emissions from the CHP when only one CHP is selected. There are no CO_2 emissions from electricity in cases 1 through 3 because no electricity purchase is allowed. CO_2 emissions from electricity represent 17.5 percent and 21 percent of total CO_2 emissions in cases 4 and 5, respectively.

Figure 9 shows the CO_2 emissions associated with the various energy sources for electricity, heating, or cooling in the district system.

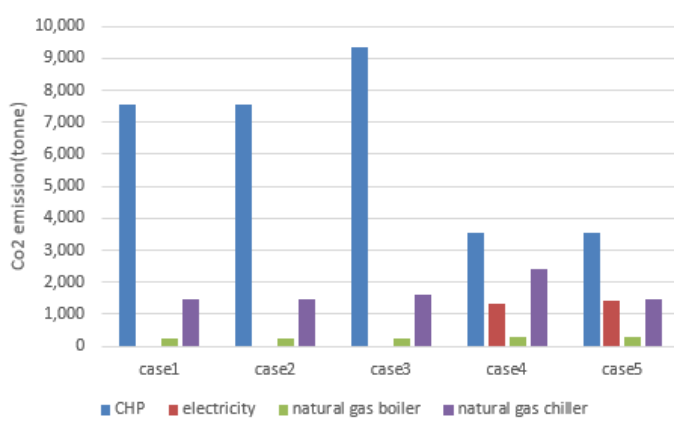

Figure 9. Comparison of CO_2 emissions from various energy sources

B. Impact of pipeline network

Among cases 1 through 3, the lowest total cost is associated with case 3, which accounts for thermal losses through the district pipeline network. In cases 1 and 2, thermal loss is treated as a percentage of the delivered thermal energy: a 0.1 percent loss for heating and a 0.15 percent loss for cooling energy. It is more realistic to account for the pipeline network than apply a set percentage when calculating the effect of thermal loss on total cost. Figure 10 shows heating and cooling losses through the network of pipelines. Figure 11 shows the effect the pipeline network has on heating provided by a CHP. Figure 12 shows the effect the pipeline network has on electrical production from PV.

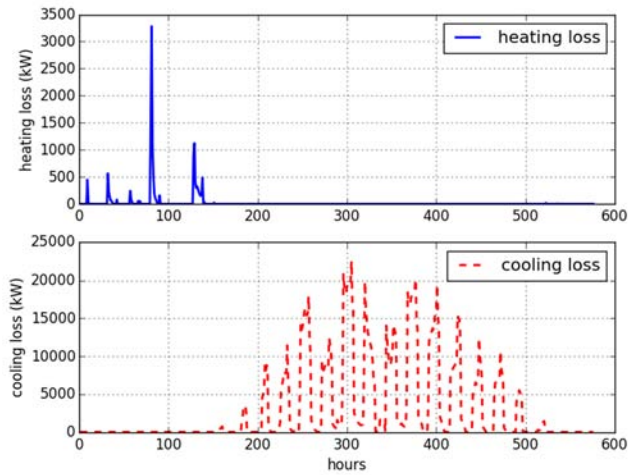

Figure 10. Losses through pipeline network

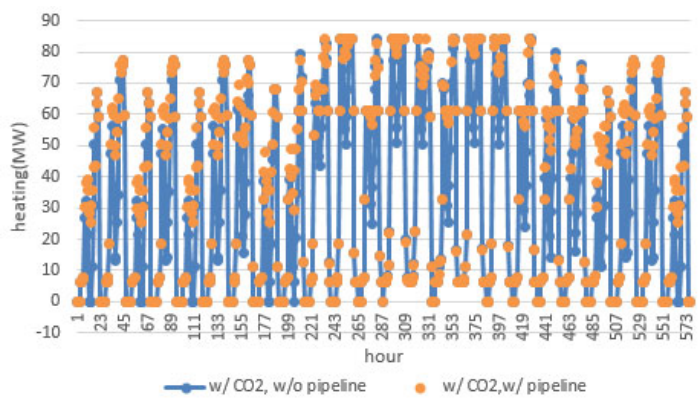

Figure 11. Effect of pipeline network on heating from CHP

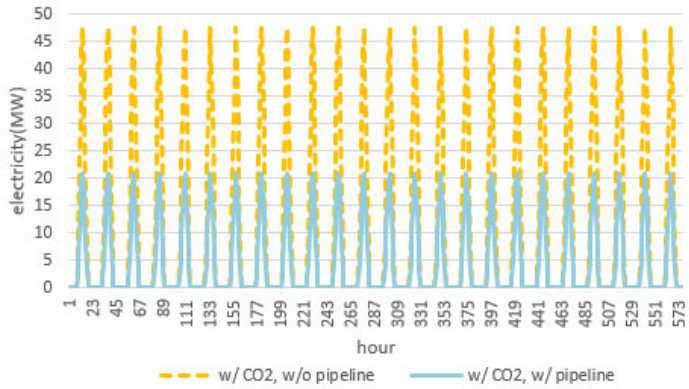

Figure 12. Effect of pipeline network on electricity from PV

C. Effect of heat tank on carbon emissions

The section investigates the reduction in carbon emissions provided when a heat tank is selected for the low-carbon community energy system.

The initial state of charge (SOC) of a heat tank is 0.85; the charge efficiency is 0.9; the discharge efficiency is 0.8; and the decay effect is 0.01. The minimum SOC of a heat tank is 0.15. A heat tank operates based on cycle charge, which means at the end of each day, the SOC of the heat tank should be the same as the initial status. The effect of CO_2 emissions on the charge status of a heat tank is unclear because of the tank's cycle charge requirement. Figure 13 shows the charge rate and SOC of the heat tank considered in case 2.

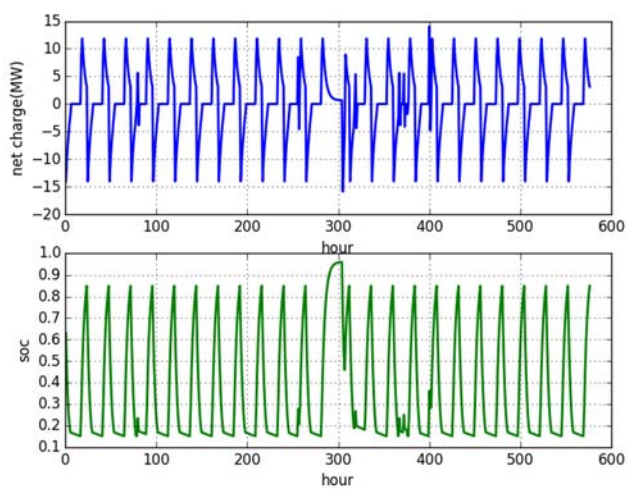

Figure 13. Charge rate and SOC of heat tank in case 2

The total cost of case 6 is 11.8 percent higher than that of case 2, because case 6 excludes the heat tank. CO_2 emissions under case 6, however, are 907 tonnes less than in case 2, as shown in Figure 14.

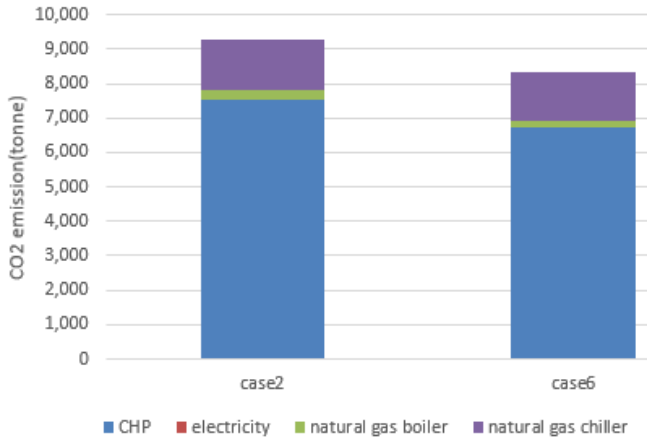

Figure 14. Comparison of CO_2 emissions under cases 2 and 6

Conclusions

In this paper, a mixed integer linear programming model was built for the community energy system planning problem. A full year horizon with 576 time periods was selected as the planning horizon. Six different cases were designed in order to compare the impact of pipeline network, CO_2 emissions and heat tank on the optimal planning of community energy systems. The results showed that the consideration of both CO_2 emissions and the pipeline network changed the PV area from 0.7 km^2 to 0.3 km^2 as compared to the cases where none of these two factors or only CO_2 emission is considered. When electricity purchase is allowed from outside the community, CHP installation will be limited to 23 MW capacity out of 4 types. It was also found that CO_2 emissions are reduced in response to the emission tax. On the other hand, losses through the pipeline network causes the highest CO_2 emission. The thermal loss consideration through the district pipeline network also reduced the total cost, which makes the model more realistic. CO2 emission without the consideration of the heat tank is much less but the total cost increased. The charging behavior of heat tank should be investigated further in order to understand the impact on CO2 emission.

Acknowledgements

This manuscript has been authored by an author at Lawrence Berkeley National Laboratory under Contract No. DE-AC02-05CH11231 with the U.S. Department of Energy. The U.S. Government retains, and the publisher, by accepting the article for publication, acknowledges, that the U.S. Government retains a non-exclusive, paid-up, irrevocable, world-wide license to publish or reproduce the published form of this manuscript, or allow others to do so, for U.S. Government purposes. This work is also supported by Shenzhen Institute of Building Research.

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