# Multi-Energy Scheduling Using a Hybrid Systems Approach

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**Abstract:** This paper presents a mixed logical dynamical (MLD) approach for modelling a multi-energy system. The electrical and thermal energy streams are linked through the operation of combined cycle power plants (CCPPs). The MLD approach is used to develop detailed models of the gas turbines (GTs), steam turbines (STs) and boilers. The power trajectories followed by the GTs, STs and boilers during various start-up methods are also modelled. The utility of the developed model is demonstrated by formulating and solving an optimal scheduling problem to satisfy both electrical and thermal loads in the system. The cost benefit of including flexible loads in the scheduling problem formulation is demonstrated through suitable case studies.

*Keywords:* Energy management systems, Hybrid systems, Mixed logical dynamical, Multi-energy systems, Optimal scheduling, Optimization problems, Power systems.

## 1. INTRODUCTION

Multi-energy systems integrate different energy streams such as electricity, heat and cooling leading to an increase in the overall energy efficiency of the system. CCPPs are key components of multi-energy systems and can supply electrical, thermal and cooling power. The operation of multi-energy networks is important for countries such as Singapore where CCPP/Co-gen/Tri-gen technologies accounted for 75% of the overall electricity generation capacity in 2015 [Energy Market Authority (2015)]. Optimal scheduling of generators in multi-energy systems is a key research problem which is non-trivial due to the significant coupling which exists between the different energy streams such as electricity and heat [Bao et al. (2015)]. Energy management systems (EMSs) typically solve an optimal day-ahead (24h) scheduling problem for all the generators in the system. This scheduling problem is commonly known as the unit commitment (UC) problem in electrical power systems. The decision variables of the UC problem are the commitment statuses (binary) and the output power setpoints (continuous) for all the system generators. Moreover, detailed generator models for scheduling problems including start-up and shutdown trajectories are developed using a mix of continuous and binary variables. In this context, hybrid systems-based modelling approaches appear to be promising candidates for formulating the UC problem. Among such approaches, the mixed logical dynamical (MLD) formalism has been used for formulating UC problems. The authors of [Krishnan et al. (2016)] developed a component-wise CCPP model using the MLD framework for an optimal self-scheduling problem. In [Krishnan et al. (2016)], the CCPP model included detailed start-up and shutdown power trajectories. The CCPP model developed in [Krishnan et al. (2016)] was further improved in [Krishnan et al. (2017)]. Apart from accounting for the electrical power produced by generators in the soak and desynchronization phases, [Krishnan et al. (2017)] also implemented variable start-up costs for different start-up methods. The authors of [Parisio et al. (2014)] used the MLD-model predictive control (MPC) framework to formulate a UC problem for microgrid operation while [Verrilli et al. (2017)] used the MLD-MPC framework to formulate an optimal scheduling problem for a district heating network. The MLD-MPC framework was also used for formulating an optimal multi-microgrid scheduling problem which also accounted for the network losses [Sampath et al. (2017)]. The optimal scheduling problems in [Krishnan et al. (2016)], [Krishnan et al. (2017)], [Parisio et al. (2014)] and [Sampath et al. (2017)] satisfied only the electrical load demand while the optimal scheduling problem in Verrilli et al. (2017) satisfied only the thermal load demand.

A mixed integer non-linear programming (MINLP) formulation for the optimal scheduling of CCPPs to satisfy thermal and electrical loads was considered in [Kim and Edgar (2014)]. While a detailed component-wise model of CCPPs was used in [Kim and Edgar (2014)], the problem formulation did not include flexible loads. The coordinated scheduling of microturbines and other distributed generators to satisfy the electrical, thermal and cooling loads in a multi-energy system was studied in [Li and Xu (2018)]. A multi-energy demand response program

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was proposed in [Alipour et al. (2017)] for the optimal management of energy hubs including combined heat and power plants. A multi-timescale and multi-energy optimal scheduling problem for satisfying electrical and cooling loads in microgrids was proposed in [Bao et al. (2015)]. The microturbine models used in [Li and Xu (2018), Bao et al. (2015) and Alipour et al. (2017)] are suitable only for microgrids and cannot be extended to CCPPs found in large power systems. In the context of multi-energy systems, the development of detailed CCPP models for formulating optimal scheduling problems has emerged as an important research area. CCPPs can operate in several modes, thereby offering a lot of flexibility to system operators. From a scheduling perspective, a CCPP model requires its actual operation to be considered in detail. The CCPP modelling approaches used by independent system operators (ISOs) such as ERCOT, PJM and NYISO were summarized in [Hui et al. (2011)]. Among these, the configuration and component-based approaches have attracted a lot of research interest [Liu et al. (2009)]. The configuration-based approach involves modelling the CCPP as a set of mutually exclusive combinations (modes) of GTs and STs. Transition paths are defined to enable switching from one mode to another. In the component-based approach, each CCPP component is modelled individually. Some advantages of the component-based approach include lower cost, inclusion of auxiliary equipment like boilers and duct burners in the overall CCPP model and consideration of constraints such as minimum on/off time and ramp limits [Liu et al. (2009)].

This work proposes an MLD-based framework for modelling multi-energy systems. First principles, component-wise models are developed for all the GTs, STs and boilers in the system. Depending on the prior downtime of the generator, three start-up methods are considered in each generator model - hot, warm and cold. Each start-up method has a unique cost associated with it. Subsequently, an optimal day-ahead scheduling problem is formulated and solved to satisfy the electrical and thermal load demands. The monetary benefits derived by including flexible electrical loads in the system is investigated through appropriate case studies.

## 2. MIXED LOGICAL DYNAMICAL APPROACH

The MLD formalism has been employed for modelling the GTs, STs and boilers in this paper. In the context of multi-energy scheduling problems, the advantage of using the MLD formalism to model all the generators in the system is that the final optimal scheduling problem turns out to be either a mixed integer linear programming (MILP) or a mixed integer quadratic programming (MIQP) problem. These classes of problems may be efficiently solved using commercial solvers such as CPLEX and Gurobi. The following equations are used to describe a hybrid system in the MLD framework [Bemporad and Morari (1999)]:

$$x(k+1) = Ax(k) + B_{\mathrm{u}}u(k) + B_{\mathrm{aux}}w(k) + B_{\mathrm{aff}} \tag{1}$$

$$E_{\mathrm{x}}x(k) + E_{\mathrm{u}}u(k) + E_{\mathrm{aux}}w(k) \leq E_{\mathrm{aff}} \tag{2}$$

where $x = [x_{\mathrm{c}}\ x_{\mathrm{b}}]^{\mathrm{T}}$, $x_{\mathrm{c}} \in \mathbb{R}^{n_{\mathrm{x}}^{\mathrm{c}}}$, $x_{\mathrm{b}} \in \{0,1\}^{n_{\mathrm{x}}^{\mathrm{b}}}$ represents the continuous and binary system states; $u = [u_{\mathrm{c}}\ u_{\mathrm{b}}]^{\mathrm{T}}$, $u_{\mathrm{c}} \in \mathbb{R}^{n_{\mathrm{u}}^{\mathrm{c}}}$, $u_{\mathrm{b}} \in \{0,1\}^{n_{\mathrm{u}}^{\mathrm{b}}}$ represents the continuous and binary system inputs and $w = [w_{\mathrm{c}}\ w_{\mathrm{b}}]^{\mathrm{T}}$, $w_{\mathrm{c}} \in \mathbb{R}^{n_{\mathrm{w}}^{\mathrm{c}}}$, $w_{\mathrm{b}} \in \{0,1\}^{n_{\mathrm{w}}^{\mathrm{b}}}$ represents the continuous and binary auxiliary variables. Auxiliary variables are used in the MLD framework to transform propositional logic into linear inequalities of the form shown in (2). $A$, $B_{\mathrm{u}}$, $B_{\mathrm{aux}}$, $B_{\mathrm{aff}}$, $E_{\mathrm{x}}$, $E_{\mathrm{u}}$, $E_{\mathrm{aux}}$ and $E_{\mathrm{aff}}$ are constant matrices of appropriate dimensions which define the interactions between the system states, system inputs and auxiliary variables. A full description of the MLD framework is provided in [Bemporad and Morari (1999)]. Hybrid system description language (HYSDEL) [Torrisi and Bemporad (2004)] was used to develop component-wise models of all the GTs, STs and boilers in the MLD framework.

## 3. MODELLING OF SYSTEM GENERATORS

The multi-energy system considered in this paper comprises 2 CCPPs (each with 1 GT and 1 ST), 3 STs and 2 boilers. Each CCPP is associated with one boiler. The technical parameters used to model all the generators considered in this paper are provided at `http://dx.doi.org/10.13140/RG.2.2.21545.29288`. GT1, ST1 and Boiler 1 are associated with CCPP 1 while GT2, ST2 and Boiler 2 are associated with CCPP 2. ST1 and ST2 derive their operational steam requirements from the waste heat produced by GT1 and GT2 respectively. Boiler 1 and Boiler 2 supplement the waste heat available from GT1 and GT2 respectively. Consequently, the fuel cost parameters for ST1 and ST2 are 0. Boiler 1 and Boiler 2 are modelled along the lines of [Kim and Edgar (2014)]. The parameters of all the other generators are adapted from [Simoglou et al. (2010)]. The following paragraphs describe the various constraints which are associated with the operation of the GTs, STs and boilers in the system.

### *3.1 Minimum up/down time constraints*

The binary input variable $u_k^g$ is forcibly set to 1 if generator $g$ enters the dispatch phase during the interval $[k - UT, k]$. Conversely, $u_k^g$ is forcibly set to 0 if the generator shutdown commences during the interval $[k - DT, k]$. UT and DT are constant parameters which represent the minimum uptime and downtime respectively. Therefore, the minimum up/down time constraints are expressed as follows:

$$\sum_{\tau=k}^{k+\mathrm{UT}-1} u_\tau^g \geq \mathrm{UT}[w_{\mathrm{disp},k}^g - w_{\mathrm{disp},k-1}^g], \quad \forall k \in K, \forall g \in \{GT, ST, BR\} \tag{3}$$

$$\sum_{\tau=k}^{k+\mathrm{DT}-1} [1 - u_\tau^g] \geq \mathrm{DT}[w_{\mathrm{shutdown},k-1}^g - w_{\mathrm{shutdown},k}^g], \quad \forall k \in K, \forall g \in \{GT, ST, BR\} \tag{4}$$

where $k$ is the index for time in hours; $g$ is the index for generators; $u_k^g$ represents the commitment status; $GT$, $ST$ and $BR$ represent the sets of GTs, STs and boilers in the system respectively; $K$ represents the set of hours in a day i.e. $K = \{1, 2, \ldots, 24\}$; $w_{\mathrm{disp},k}^g$ is a binary auxiliary variable which is set to 1 if generator $g$ enters the dispatch phase and $w_{\mathrm{shutdown},k}^g$ is a binary auxiliary variable which is set to 1 if the shutdown of generator $g$ is initiated. UT and DT have both been set at 3 hours for all the GTs, STs and boilers in this paper.

### 3.2 Start-up type selection

The prior downtime of a generator is used to determine the appropriate start-up method. The following constraint ensures that only one start-up method is selected:

$$w^g_{\text{start-up},k} \le \sum_{n\in N} w^{n,g}_{\text{start-up},k}, \forall k \in K, \forall g \in \{GT, ST, BR\} \quad (5)$$

$$w^{n,g}_{\text{start-up},k} \le \sum_{\tau=k-t_{\mathrm{u}}^{n,g}+1}^{k-t_1^{n,g}} w^g_{\text{shutdown},\tau}, \quad \forall k \in K, \forall g \in \{GT, ST, BR\} \quad (6)$$

where $n$ = cold $\vee$ warm $\vee$ hot; $w^{n,g}_{\text{start-up},k}$ is a binary auxiliary variable which is set to 1 if start-up method $n$ is initiated. This is possible only if generator $g$ has been shutdown during the time interval $[k - t_{\mathrm{u}}^{n,g}, k - t_1^{n,g}]$. Finally, $w^g_{\text{start-up},k}$ is a binary auxiliary variable which is set to 1 if generator $g$ undergoes any start-up method.

### 3.3 Synchronization, Soak and Desynchronization Phases

Each ST enters the synchronization phase once it is started up. The duration of this phase depends on the start-up method. This may be expressed as follows:

$$w^{n,g}_{\text{synch},k} = \sum_{\tau=k-t^{n,g}_{\text{synch}}+1}^{k} w^{n,g}_{\text{start-up},\tau}, \ \forall k \in K, \forall g \in ST \quad (7)$$

where $w^{n,g}_{\text{synch},k}$ is a binary auxiliary variable which is set to 1 if generator $g$ is in the synchronization phase corresponding to start-up method $n$ and $t^{n,g}_{\text{synch}}$ is the synchronizing time (in hours) required for start-up method $n$.

The STs enter the soak phase after they are synchronized with the grid. The GTs and boilers enter the soak phase on getting committed without undergoing the synchronization phase. The duration of the soak phase depends on the start-up method selected. The following constraint ensures that only the binary auxiliary variable corresponding to the soak phase of the selected start-up method is set to 1 as the generator progresses along the various stages of the soak phase.

$$w^{n,g}_{\text{soak},k} = \sum_{\tau=k-t^{n,g}_{\text{synch}}-t^{n,g}_{\text{soak}}+1}^{k-t^{n,g}_{\text{synch}}} w^{n,g}_{\text{start-up},\tau}, \quad \forall k \in K, \forall g \in \{GT, ST, BR\} \quad (8)$$

where $w^{n,g}_{\text{soak},k}$ is a binary auxiliary variable which is set to 1 if generator $g$ is in the soak phase corresponding to the start-up method $n$ and $t^{n,g}_{\text{soak}}$ is the soak time (in hours) required for the start-up method $n$. The real power produced by a GT or ST during the soak phase may increase linearly to its technical minimum value. In this paper, it is assumed that a constant power, $P^g_{\text{soak},k}$ is produced during soak phase by all the GTs and STs.

Once decommitted, a generator spends a certain number of hours in the desynchronization phase. During this phase, the real power output from the GTs and STs first decreases to the technical minimum value and subsequently to 0MW. This is achieved through the following constraint by setting a desynchronization phase binary variable to 1.

$$w^g_{\text{desyn},k} = \sum_{\tau=k+1}^{k+t^g_{\text{desyn}}} w^g_{\text{off},\tau} \ \forall k \in K, \forall g \in \{GT, ST\} \quad (9)$$

where $w^g_{\text{desyn},k}$ is a binary auxiliary variable which is set to 1 if the generator $g$ is in the desynchronization phase; $w^g_{\text{off},k}$ is a binary auxiliary variable which is set to 1 if the power output drops to 0MW and $t^g_{\text{desyn}}$ is the desynchronization time in hours. The boilers do not produce any thermal power during the soak and desynchronization phases.

### 3.4 Spinning Reserve Constraints

The spinning reserve constraints for this system are defined as follows:

$$\sum_{g\in\{GT,ST\}} SR^g_k x^g_{\text{disp},k} \ge SR_k, \ \forall k \in K \quad (10)$$

$$SR^g_k x^g_{\text{disp},k} \le 10MSR^g, \ \forall k \in K, \forall g \in \{GT, ST\} \quad (11)$$

$$SR^g_k x^g_{\text{disp},k} + P^g_{\mathrm{e},k} x^g_{\text{disp},k} \le P^g_{\mathrm{e,max}}, \ \forall k \in K, \forall g \in \{GT, ST\} \quad (12)$$

where $x^g_{\text{disp},k}$ is a binary state variable which is set to 1 if generator $g$ is in dispatch phase; $SR^g_k$ is the spinning reserve contributed; $SR_k$ is the total system spinning reserve requirement; $MSR^g$ is the maximum spinning rate in MW/min; $P^g_{\mathrm{e},k}$ is the real power (in MW) produced in the dispatch phase and $P^g_{\mathrm{e,max}}$ is the upper bound on the real power produced in MW.

### 3.5 Ramping Constraints

Ramping constraints are imposed only on the electrical power output of the STs since the GTs are assumed to be fast ramping generators.

$$-0.5P^g_{\mathrm{e,max}} \le P^g_{\mathrm{e},k} x^g_{\text{disp},k} - P^g_{\mathrm{e},k-1} x^g_{\text{disp},k-1} \le 0.5P^g_{\mathrm{e,max}}, \ \forall k \in K, \forall g \in ST \quad (13)$$

### 3.6 Thermal Power Generation Constraints

The performance of the bottoming cycle in CCPPs depends on the performance of the topping cycle. The total waste heat emitted by the GT is divided between the ST and the thermal power distribution network.

$$P^g_{\mathrm{h},k} = a^g_0 P^g_{\mathrm{e},k} x^g_{\text{disp},k} + a^g_1, \ \forall k \in K, \forall g \in GT \quad (14)$$

$$P^g_{\mathrm{h},k} = b^g_0 w^g_{\mathrm{br},k}, \ \forall k \in K, \forall g \in BR \quad (15)$$

$$h^g_k = h^g_0 P^g_{\mathrm{e},k} + h^g_1, \ \forall k \in K, \forall g \in \{\mathrm{ST1}, \mathrm{ST2}\} \subseteq ST \quad (16)$$

$$P^{\mathrm{GT1}}_{\mathrm{h},k} + P^{\text{Boiler 1}}_{\mathrm{h},k} \ge h^{\mathrm{ST1}}_k \quad (17)$$

$$P^{\mathrm{GT2}}_{\mathrm{h},k} + P^{\text{Boiler 2}}_{\mathrm{h},k} \ge h^{\mathrm{ST2}}_k \quad (18)$$

where $P^g_{\mathrm{h},k}$ is the thermal power produced in MW; $w^g_{\mathrm{br},k}$ is the fuel consumed in mcf; $a^g_0$ and $a^g_1$ are constant coefficients of the electrical power - thermal power curve; $b^g_0$ is a conversion factor for relating fuel consumption and thermal power production; $h^g_k$ is the thermal power consumed in MW while $h^g_0$ and $h^g_1$ are constant coefficients of the electrical power-thermal power curve. In this paper, $a^{\mathrm{GT1}}_0 = 1.35$, $a^{\mathrm{GT1}}_1 = 97.09$; $a^{\mathrm{GT2}}_0 = 1.14$, $a^{\mathrm{GT2}}_1 = 96.32$; $b^{\text{Boiler 1}}_0 = 0.0004$; $b^{\text{Boiler 2}}_0 = 0.0003$; $h^{\mathrm{ST1}}_0 = 1.74$, $h^{\mathrm{ST1}}_1 = 72.05$; $h^{\mathrm{ST2}}_0 = 0.82$, $h^{\mathrm{ST2}}_1 = 85.58$.

## 4. MULTI-ENERGY SCHEDULING PROBLEM

A day-ahead scheduling problem optimally allocates generation resources for the next day (24h) based on a forecast of the expected electrical and thermal load demands in the system. The multi-energy scheduling problem for this paper is formulated in the following paragraphs.

### *4.1 Flexible Loads*

Flexible loads are loads which can be scheduled to operate in a manner which reduces the electricity cost of the system while respecting the operational constraints. Flexible loads can help in reducing or eliminating uncontracted capacity costs which are exorbitant. They also help system operators take advantage of periods when electricity prices are low. In this paper, flexible loads are assumed to be large industrial pump loads. The operational constraints on the flexible loads are described in the following equations:

$$\sum_{\substack{k\in K\\ l\in L}} Q_l u_k^l \geq \mathrm{V} \tag{19}$$

where $L$ is the set of pumps (flexible loads) in the system; $l$ is the index for pumps; $Q_l$ is the flow rate; $u_k^l$ is the commitment status and V is the total liquid volume which needs to be pumped in 24 hours. Further, large pumps cannot be started up and shutdown too often due to their large inertias. The following constraint limits the number of times each pump can be started up in a 24-hour period:

$$\sum_{k\in K} w_{\mathrm{SU},k}^l \leq w_{\mathrm{SU,max}}^l,\ \forall l\in L \tag{20}$$

$$\text{and, } w_{\mathrm{SU},k}^l = u_k^l(u_k^l - u_{k-1}^l) \tag{21}$$

where $w_{\mathrm{SU},k}^l$ is a binary variable which is set to 1 if pump $l$ is started up and $w_{\mathrm{SU,max}}^l$ is the maximum number of start-ups permitted in a 24-hour period. Equation (21) is reformulated as follows:

$$w_{\mathrm{SU},k}^l \leq (u_k^l + 1 - u_{k-1}^l)/2 \tag{22}$$

$$w_{\mathrm{SU},k}^l \geq (u_k^l - u_{k-1}^l)/2 \tag{23}$$

A total of 7 flexible pump loads are considered in this paper - 3 main pumps and 4 auxiliary pumps. $Q_l$ = 72000 $\mathrm{m}^3$/h for the main pumps and $Q_l$ = 3600 $\mathrm{m}^3$/h for the auxiliary pumps. The power ratings of the main pumps and auxiliary pumps are 4.35MW and 0.33MW respectively. Finally, V = 600000 $\mathrm{m}^3$. It is assumed that pump speeds are not adjustable. This implies that a pump runs at normal speed and consumes nominal power if it is scheduled.

### *4.2 Problem Formulation*

The UC problem optimally schedules all the GTs, STs and boilers in the system to satisfy the electrical and thermal load demands while respecting all the operational constraints described in Sections 3 and 4.1. In this paper, the UC problem is solved under the assumption that point forecasts for thermal load demand, electrical load demand and prices for buying/selling electrical power from/to the utility grid are available. The different terms of the objective function are described below.

$C_{\mathrm{Fuel}}$ is the fuel cost incurred in operating the GTs and STs in the system. It is assumed that the GTs use natural gas as fuel while the STs which are not associated with any CCPP use coal as fuel.

$$C_{\mathrm{Fuel}} = \sum_{\substack{k\in K\\ g\in\{GT,ST\}}} x_{\mathrm{disp},k}^g \left(c_2^g\left(P_{\mathrm{e},k}^g\right)^2 + c_1^g P_{\mathrm{e},k}^g + c_0^g\right) \tag{24}$$

where $c_2^g$, $c_1^g$ and $c_0^g$ are the fuel cost coefficients in \$/MW$^2$, \$/MW and \$ respectively.

$C_{\mathrm{SU}}$ calculates the cost incurred during the start-up process of all the generators in the system. Different start-up cost coefficients are used for hot, warm and cold start-up methods as shown below.

$$C_{\mathrm{SU}} = \sum_{\substack{k\in K\\ g\in\{GT,ST,BR\}}} (C_{\mathrm{cold}}^g(w_{\mathrm{synch},k}^{\mathrm{cold},g} + w_{\mathrm{soak},k}^{\mathrm{cold},g}) + C_{\mathrm{warm}}^g(w_{\mathrm{synch},k}^{\mathrm{warm},g} + w_{\mathrm{soak},k}^{\mathrm{warm},g}) + C_{\mathrm{hot}}^g w_{\mathrm{soak},k}^{\mathrm{hot},g}) \tag{25}$$

where $C_{\mathrm{cold}}^g$, $C_{\mathrm{warm}}^g$ and $C_{\mathrm{hot}}^g$ are the cost coefficients for cold, warm and hot start-up methods respectively in \$.

$C_{\mathrm{SD}}$ evaluates the cost incurred during shutdown of all the generators in the system.

$$C_{\mathrm{SD}} = \sum_{\substack{k\in K\\ g\in\{GT,ST,BR\}}} C_{\mathrm{sd}}^g w_{\mathrm{desyn},k}^g \tag{26}$$

where $C_{\mathrm{sd}}^g$ is the shutdown cost coefficient in \$.

$C_{\mathrm{Grid}}$ represents the cost incurred due to the purchase of electrical and thermal power from the utility grid. $C_{\mathrm{Grid}}$ is calculated as follows:

$$C_{\mathrm{Grid}} = C_{\mathrm{p},k}P_{\mathrm{eb},k} - C_{\mathrm{s},k}P_{\mathrm{es},k} + C_{\mathrm{heat}}P_{\mathrm{hb},k} \tag{27}$$

where $P_{\mathrm{es},k}$ is the electrical power sold to the utility grid in MW; $P_{\mathrm{eb},k}$ is the electrical power purchased from the utility grid in MW; $P_{\mathrm{hb},k}$ is the thermal power purchased from external producers in MW; $C_{\mathrm{p},k}$ is the cost of electrical power purchased from the utility grid and $C_{\mathrm{s},k}$ is the cost of electrical power sold to the utility grid and $C_{\mathrm{heat}}$ = \$100/MW is the price of thermal power purchased from external producers. In this paper, $P_{\mathrm{eb},k}^{\max}$=$P_{\mathrm{es},k}^{\max}$ = 30MW and $P_{\mathrm{hb},k}^{\max}$ = 80MW.

$C_{\mathrm{UCC}}$ is the cost incurred due to uncontracted capacity. $C_{\mathrm{UCC}}$ is evaluated as shown below.

$$P_{\mathrm{UC}} = \max\{0, \max\{P_{\mathrm{eb},k} - \mathrm{CC}\}\},\ \forall k\in K \tag{28}$$

where $P_{\mathrm{UC}}$ is the uncontracted capacity in MW and CC is the contracted capacity in MW. Equation (28) is linearized as follows:

$$P_{\mathrm{UC}} \geq P_{\mathrm{eb},k} - \mathrm{CC},\ \forall k\in K \tag{29}$$

$$P_{\mathrm{UC}} \geq 0 \tag{30}$$

$$\text{and } C_{\mathrm{UCC}} = U_{\mathrm{CC}}P_{\mathrm{UC}} \tag{31}$$

where $U_{\mathrm{CC}}$ = \$12,860/MW/month and CC=25MW.

$C_{\mathrm{Boiler}}$ evaluates the fuel cost incurred by the boilers for producing thermal power. It is assumed that all the boilers use natural gas priced at \$3.81/mcf as fuel.

$$C_{\mathrm{Boiler}} = \sum_{\substack{k\in K\\ g\in BR}} 3.81 w_{\mathrm{br},k}^g \tag{32}$$

The overall optimization problem is summarized below.

$$\min_{u,x,w} J = C_{\text{Fuel}} + C_{\text{SU}} + C_{\text{SD}} + C_{\text{Grid}} + C_{\text{UCC}} + C_{\text{Boiler}}$$
$$\text{subject to } (1),\ (2)$$
$$u_{\min} \leq u \leq u_{\max};\, x_{\min} \leq x \leq x_{\max};\, w_{\min} \leq w \leq w_{\max}$$
$$P_{\text{De},k} = \sum_{g\in\{GT,ST\}} (P^g_{\text{e},k} + P^g_{\text{soak},k}) + P_{\text{eb},k} - P_{\text{es},k}$$
$$P_{\text{Dh},k} + \sum_{g\in\{\text{ST1},\text{ST2}\}} h^g_k = \sum_{g\in\{GT,BR\}} (P^g_{\text{h},k}) + P_{\text{hb},k} \tag{33}$$

where $P_{\text{De},k}$ and $P_{\text{Dh},k}$ are the total electrical and thermal load demands (in MW) in the system respectively. The overall optimization problem turns out to be an MIQP problem which is described in MATLAB using YALMIP [Lofberg (2004)] and solved using CPLEX.

## 5. CASE STUDIES AND DISCUSSIONS

The electrical and thermal load demand forecasts are shown in Fig. 1(a). The time varying electricity prices illustrated in Fig. 1(b) were obtained from the Singapore Energy Market Company's website. To demonstrate the utility of the optimal multi-energy scheduling problem presented in earlier sections, the following scenarios were simulated:

(1) Load scheduling is not performed. The liquid is pumped out in the fastest possible time using only the main pumps.
(2) Load scheduling is performed to take advantage of the flexibility offered by the auxiliary pumps and the lower electricity prices during specific hours.

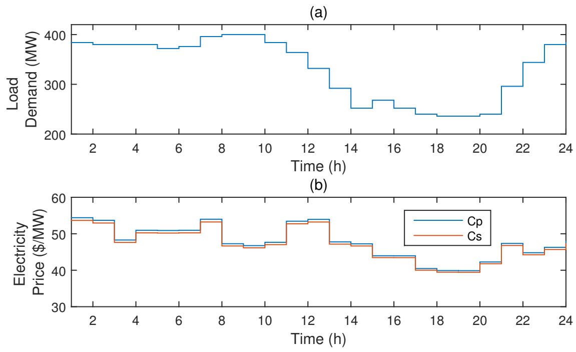


Fig. 1. (a) Load demand forecast. (b) Electricity price forecast.

In Scenario 2, the system model was initialized as follows: all main and auxiliary pumps were switched off; GT1 and GT2 were in the dispatch phase; ST1, ST3, ST4 and ST5 were in the dispatch phase; ST2 was in the soak phase of cold start-up; Boiler 1 and Boiler 2 were in the dispatch phase.

Optimal CCPP schedules under Scenario 2 are shown in Fig. 2. Fig. 2(a) illustrates the electrical power produced by GT1 and GT2 under Scenario 2. It is observed that both GTs run at full capacity throughout the day. Fig. 2(b) shows the electrical power produced by ST1 and ST2 under Scenario 2. It is observed that ST1 is shutdown during hour 3 and subsequently undergoes a hot start-up during hour 7. It undergoes another shutdown during

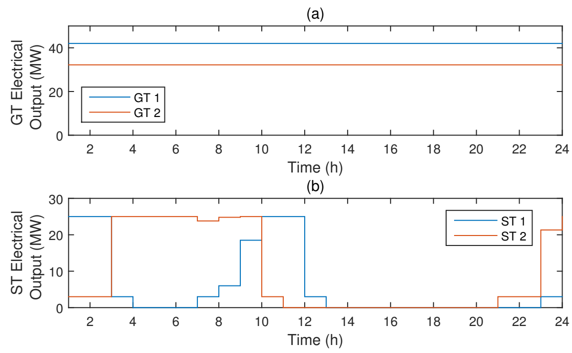


Fig. 2. (a) Electrical power output from GT1 and GT2. (b) Electrical power output from ST1 and ST2.

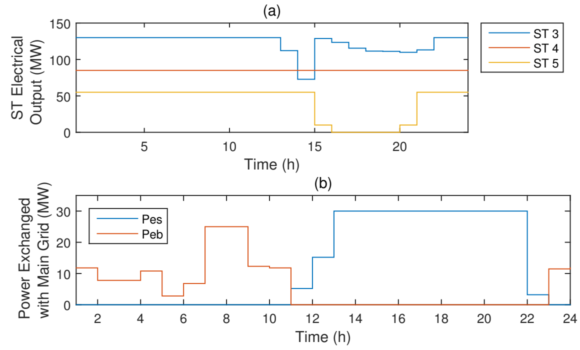


Fig. 3. (a) Electrical power output from ST3, ST4 and ST5. (b) Electrical power exchanged with the utility grid.

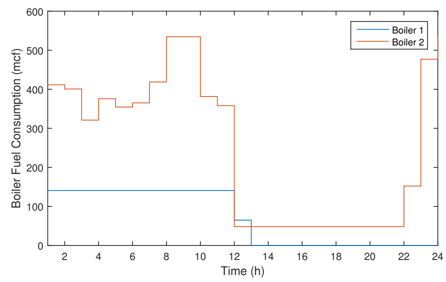


Fig. 4. Fuel consumption by Boiler 1 and Boiler 2.

hour 12 and a warm start-up starting from hour 22. ST2 undergoes a shutdown during hour 10. Subsequently, ST2 undergoes a warm start-up starting from hour 20. The electrical power outputs of ST3, ST4 and ST5 are shown in Fig. 3(a). ST3 operates throughout the day with its output varying in accordance with the electrical load demand in the system. ST4 operates at full capacity throughout the day while ST5 is shutdown in hour 15 when the load demand reduces. Subsequently, it is started up during hour 20. From Fig. 3(b), it is observed that electrical power is purchased from the utility grid during the first 11 hours of the day and during the last hour when the load demand is high. Electrical power is sold to the utility grid during all the other hours when there is excess generation available after satisfying all the electrical and thermal loads. For both Scenarios 1 and 2, no uncontracted capacity charges were incurred since the power imported from the upstream grid was within the contracted capacity as seen in Fig. 3(b). Finally, the fuel consumed by both

Table 1. Schedules of pump loads.

| | **Scenario 1** | **Scenario 2** |
|---|---|---|
| **Main Pump 1** | (1,1,1,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0) | (0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0) |
| **Main Pump 2** | (1,1,1,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0) | (0,0,0,0,0,0,0,0,0,0,0,0,1,1,0,0,0,0,0,0,0,0,0,0) |
| **Main Pump 3** | (1,1,1,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0) | (0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,1,1,1,1,0,0) |
| **Auxiliary Pump 1** | Not Applicable | (0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0,0,0,0) |
| **Auxiliary Pump 2** | Not Applicable | (0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0) |
| **Auxiliary Pump 3** | Not Applicable | (0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0,0,0) |
| **Auxiliary Pump 4** | Not Applicable | (0,0,0,1,1,0,0,0,0,0,0,0,0,1,0,1,1,1,0,0,0,0,0,0) |
| **Objective Function Value ($)** | 159831.23 | 158149.69 |

boilers is shown in Fig. 4. Both boilers supplement the waste heat from their respective GTs during the peak load hours. For both scenarios, no external heat was purchased owing to its prohibitive cost arising from the need to install heat exchangers to transport thermal energy. The monetary benefits derived from including flexible loads in the problem formulation were evaluated. The results in Table 1 clearly establish the benefits of including flexible loads. Without optimal scheduling, the main pumps were operated during the first 3 hours of the day irrespective of the electricity price. The auxiliary pumps were not utilized owing to their lower pumping efficiencies. In Scenario 2, the operation of pumps was shifted to later hours to take advantage of varying electricity prices. Moreover, the auxiliary pumps were operated to reduce dependence on the main pumps. Overall, the electricity cost in Scenario 2 was 1.05% lower than Scenario 1.

## 6. CONCLUSIONS

In this paper, an MLD-based model for multi-energy systems was developed. Detailed component-wise models were developed for GTs, STs and boilers. Additionally, a model was developed for flexible pump loads. An optimal day-ahead scheduling problem for meeting thermal and electric load demands was formulated and solved, thereby demonstrating the efficacy of the developed model. The monetary benefits derived from the inclusion of flexible loads in the problem formulation were demonstrated through suitable case studies. The framework developed in this paper may be extended further to include renewable energy sources and energy storage systems (both electrical and thermal). In this paper, network constraints were not accounted for in the optimization problem. The thermal energy produced may also be integrated with a park level waste heat recovery network in large industrial parks.

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