Studies on Customer Side Electricity Load Management for Sustainable Manufacturing Systems

BY

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THESIS

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TABLE OF CONTENTS

1. INTRODUCTION 1

2. METHOD I: OPTIMAL PRODUCTION SCHEDULING UNDER CRITICAL PEAK PRICING ELECTRICITY DEMAND RESPONSE PROGRAM FOR SUSTAINABLE MANUFACTURING SYSTEMS 7

2.1 Motivation and Introduction 7

2.2 Proposed Method 9

2.3 Case Study 17

2.4 Conclusions 23

3. METHOD II: OPTIMAL PRODUCTION SCHEDULING AND ON-SITE GENERATION UTILIZATION FOR SUSTAINABLE MANUFACTURING SYSTEMS 24

3.1 Motivation and Introduction 24

3.2 Proposed Method 27

3.3 Case Study 33

3.4 Conclusions 43

4. CONCLUSIONS AND FUTURE WORK 44

VITA 51

LIST OF FIGURES

FIGURE PAGE

Figure 1. CHP system with steam turbine technology 4

Figure 2. Types of time interval under CPP program 7

Figure 3. A typical production system with *N* machines and *N*-1 buffers 9

Figure 4. Flow chart of the approximate method 15

Figure 5. A serial production system with five machines and four buffers 17

Figure 6. Capacity reservation and power consumption of the billing cycle 21

Figure 7. Comparison of the 95% confidence interval of the cost between the proposed method and two other methods 22

Figure 8. CO2 emissions comparison between CHP system and separated energy generation systems 24

Figure 9. Energy efficiency comparison between CHP system and separated energy generation systems 25

Figure 10. Types of time interval under TOU program 26

Figure 11. CHP system with an auxiliary boiler 27

Figure 12. A serial production system with five machines and four buffers connected to a CHP system and an auxiliary boiler 33

Figure 13. Daily hourly rate under TOU program 36

Figure 14. Power consumption and CHP usage of the billing cycle 38

Figure 15. Heat demand and heat generated from CHP and auxiliary boiler 39

LIST OF FIGURES (continued)

FIGURE PAGE

Figure 16. Power consumption of the billing cycle without CHP system. 40

Figure 17. Comparison of the 95% confidence interval of the cost between the system with CHP and the system without CHP. 41

LIST OF TABLES

TABLE PAGE

TABLE I. MACHINES CHARACTERISTICS 17

TABLE II. PARAMETERS OF THE BUFFERS 17

TABLE III. MONTHLY SCHEDULE 18

TABLE IV. ELECTRICITY RELATED RATES AND UNIT PENALTY COST 19

TABLE V. WEEKLY TARGET PRODUCTION AND ALLOWED MAXIMUM UNFULFILLED PRODUCTION 19

TABLE VI. WEEKLY PRODUCTION 20

TABLE VII. SCHEDULED AND SIMULATED RESULTS OF WEEKLY PRODUCTION 20

TABLE VIII. COST COMPARISON BETWEEN THE PROPOSED METHOD AND TWO OTHER METHODS 22

TABLE IX. MACHINES CHARACTERISTICS 34

TABLE X. PARAMETERS OF THE BUFFERS 34

TABLE XI. CHP AND AUXILIARY BOILER PARAMETERS, ENERGY CAPACITY OF NATURAL GAS AND HEAT DEMAND 35

TABLE XII. ELECTRICITY RELATED RATES, DEMAND CHARGE, CHP SETUP COST, NATURAL GAS COST AND EXCEEDED HEAT PENALTY COST 37

TABLE XIII. WEEKLY TARGET PRODUCTION 37

TABLE XIV. WEEKLY SCHEDULED PRODUCTION 39

TABLE XV. COST COMPARISON BETWEEN THE SYSTEM WITH CHP AND THE SYSTEM WITHOUT CHP 40

LIST OF TABLES (continued)

<u>TABLE</u> <u>PAGE</u>

TABLE XVI. PAYBACK ANALYSIS FOR CHP SYSTEM BASED ON CASE STUDY......... 42

LIST OF ABBREVIATIONS

CHP	Combined Heat and Power
CPP	Critical Peak Pricing
FERC	Federal Energy Regulatory Commission
GHG	Green House Gas
MINLP	Mixed Integer Nonlinear Programming
MIP	Mixed Integer Programming
NLP	Nonlinear Programming
OBMC	Optional Binding Mandatory Curtailment
PG&E	Pacific Gas & Electric
RTP	Real Time Pricing
SDG&E	San Diego Gas & Electric
TOU	Time of Use

SUMMARY

Customer side electricity load management is considered a promising means to reduce the electricity demand during peak periods. The potential greenhouse gas emissions can be reduced and the investment for the building and operating peaking power generators can be cut down. Compared with the mature research of the electricity load management for the customers in residential and commercial building sectors, very few studies dedicating to the industrial manufacturing systems have been implemented.

This thesis presents two customer-side electricity load management methodologies, i.e., electricity demand response and on-site generation for the typical manufacturing systems to help the manufacturers reduce the energy consumption during peak periods and overall electricity related cost. We first focus on the electricity demand response for typical manufacturing systems with multiple machines and buffers. Critical Peak Pricing (CPP), a typical electricity demand response program, is selected for mathematical modeling establishment using a Mixed Integer Nonlinear Programming (MINLP). The optimal production schedule and corresponding capacity reservation under the CPP program are identified by minimizing the overall cost. After that, the methodology focusing on the utilization of Combined Heat and Power (CHP) energy systems are presented and likewise, a MINLP model is established to optimize the schedule of production system and CHP system. Two case studies are conducted for both models to demonstrate the effectiveness of the proposed methods.

1. INTRODUCTION

During the past several decades, the United States has witnessed a significant electricity price increase due to both the increasing fossil fuel cost and the growing capital cost of generation infrastructure [1]. The Energy Information Administration (EIA) of the United States forecasts that the increase trend will continue for the next several decades. An approximate 33% rise of electricity rate is expected from 8.2 cents per kilowatt-hour in 2011 to 10.9 cents per kilowatt-hour in 2035 and a corresponding 30% rise of electricity demand of the country is also expected from 3,873 billion kilowatt-hours in 2008 to 5,021 billion kilowatt-hours in 2035 [2].

Two major types of negative impact due to the increasing electricity demand have been recognized. The first concern is in terms of environmental protection point of view. It is considered a threat to the sustainability of the whole society due to the huge volume of potential Greenhouse Gas (GHG) emissions. The second concern is with respect to the financial investment. About $2 trillion investment for the new generation capacity, including transmission and distribution infrastructure is estimated to satisfy the growing demand [3].

To relieve the potential negative impact, many studies focusing on integrated energy supply and consumption system on different levels towards sustainability have been conducted. For example, future energy system of a given society was modeled and evaluated considering the supply of renewable energy [4]. The energy use patterns in the future and consequent environmental impact were analyzed and discussed on a worldwide perspective [5]. The options for the sustainable development of the energy supply system in an island environment to reduce greenhouse gas emissions were investigated [6]. The local implementation of sustainable energy supply system to examine the potential for regional energy supply options to realize a sustainable manner of energy supply with reduced carbon intensity was studied [7]. The fuel and electricity intensity of the manufacturing sector of the United States was modeled and forecasted [8-10]. The environmental principles and industrial practice were analyzed to develop a conceptual manufacturing ecosystem model as a foundation to improve environmental performance [11]. A general method to help firms coordinate efficiency and sustainability based on environmental innovation was developed [12]

In addition, the studies focusing on balancing the demand and the supply of the electricity of power grid and better utilizing existing generation infrastructure have also been widely conducted. Many papers investigating the solutions in terms of the supply side point of view can be found [13-16]. Besides, customer side electricity load management is also of high interests to both government and society. In this thesis, we will conduct some initial investigations on two popular customer side electricity load management methodologies, i.e., electricity demand response and on-site electricity generation.

Electricity demand response is defined as "the changes in electricity usage by end-use customers from their normal consumption patterns in response to the changes in the price of electricity over time or the incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" by Federal Energy Regulatory Commission (FERC) [17]. Different demand response programs designed by the power utilities are available to the customers in the market to relieve the unbalanced situation of electricity demand and power supply. Generally, existing demand response programs can be categorized into two groups, *i.e.*, price-driven and event-driven [18]. In the price-driven program, varying electricity rates over different periods are designed to encourage the customers to alter their regular consumption patterns to shift the power demand from peak periods to off peak periods. The rates for the next contractual period, e.g., one year, are usually distributed to the customers in advance. Different types of price-driven programs, e.g., Time of Use (TOU), Critical Peak Pricing (CPP), and Real Time Pricing (RTP), are available [18]. In the event-driven program, the supply side can issue the request of power demand reduction based on some specific triggering events, e.g., extreme weather condition, transmission congestion, and customer side spinning reserve, to the customers who can be rewarded by effectively responding to the request. The notification is usually issued on a short notice and therefore the customers have to make their decisions on a real time basis.

Customers can respond to demand response programs to minimize their electricity bills. There are two main determining factors for industrial electricity bills, *i.e.*, *kilowatt-hour consumption and kilowatt demand*. The kilowatt-hour consumption is the total electricity consumed during the billing cycle, while the kilowatt demand is defined as the highest average power of any 15-minute periods throughout the whole billing cycle (see, for example, http://www.motorsanddrives.com/cowern/motorterms10.html). The impact of the demand response programs is enormous. It is reported that the average energy saving ratio of demand response is approximately 65 kWh per kW of peak demand reduction [19].

Besides the electricity demand response, on-site generation technology has also attracted wide attention in recent years due to its considerable environmental benefits. Combined heat and power (CHP) system, a typical on-site generation technique, is the simultaneous production of electricity and heat from a single fuel source such as natural gas, biomass, biogas, coal, waste heat, or oil. An example of the CHP system with steam turbine technology in illustrated in Figure 1. The combustion in the boiler can generate the steam that will be used by the heating/cooling unit to generate either usable heat or to provide cool air to the facility. At the same time, the steam will also be used by steam turbine to transform it into mechanical energy. The generator that is attached to the steam turbine can provide electricity to the facility/grid.

CHP system is not a single technology, but an integrated energy system that can be modified depending upon the needs of the energy end user [20]. It offers considerable environmental benefits when compared with purchased electricity and on-site generated heat. By capturing and utilizing heat that would otherwise be wasted from the production of electricity, CHP systems require less fuel than equivalent separated heat and power systems to produce the same amount of energy [21].

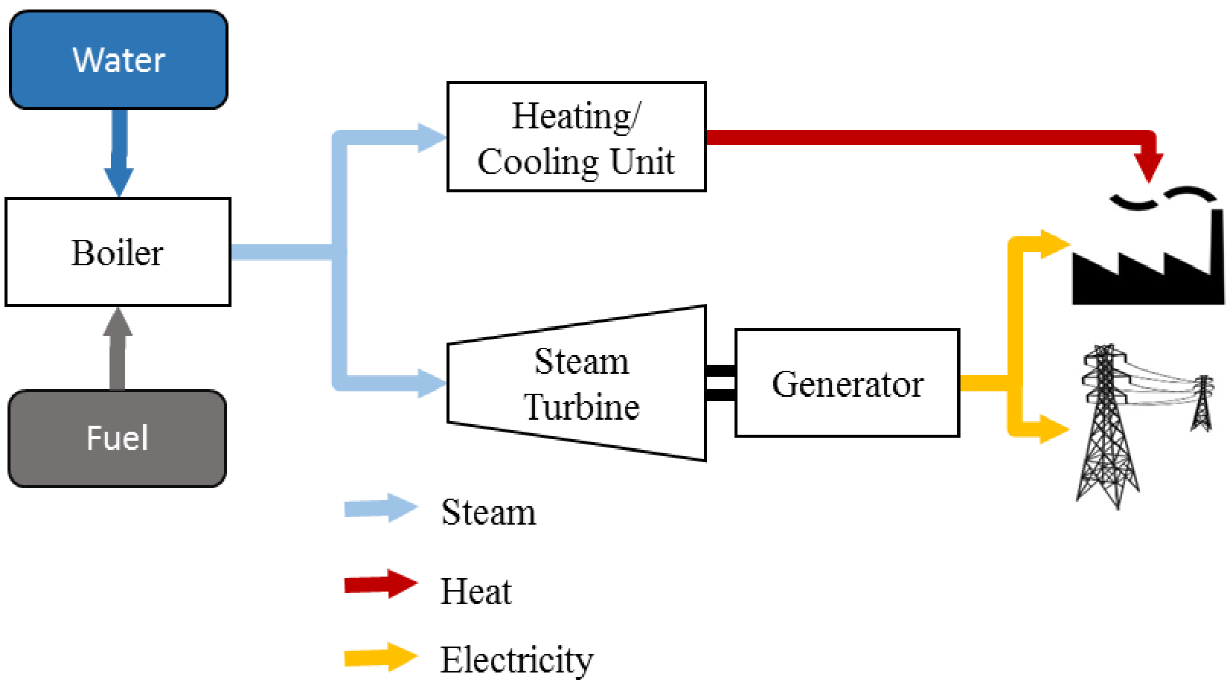

Figure 1. CHP system with steam turbine technology

A great number of studies concentrating on the electricity demand response and CHP utilization for the commercial and residential building customers have been implemented [22-33]. The control actions adopted by those types of customers are generally independent among each other [34]. However, for the industrial system, the state-of-the-art of the application of customer-side electricity load management is less developed than the ones in the commercial and residential building sectors [35] due to the high interconnections among the manufacturing machines and buffers in the manufacturing systems, although almost 20% of the total peak electricity demand in the United States is contributed by industrial sector [36]. Only a few related studies focusing on the implementation of the demand response programs and CHP systems utilization for the industry are available. For the demand response programs, Chao and Chen [37] and Chao and Zipkin [38] studied Optional Binding Mandatory Curtailment (OBMC) Plan offered by Pacific Gas & Electric (PG&E) [39], a typical event-driven program, from the manufacturer's perspective by utilizing Markov decision processes to identify the optimal production strategies when that program is offered. These two studies over simplify the typical manufacturing systems with multiple machines and buffers into a single machine system. In addition, Ashok and Banerjee established a physical-based formulation to schedule the production of a flour mill using Mixed Integer Programming (MIP) to minimize the total electricity consumption cost as well as other operation costs [40]. Later, Ashok further integrated the cost of power demand charge into the mathematical model for a small steel plant to minimize the overall operation cost [41]. These two studies mainly focus on the batch processes and cannot address typical manufacturing systems with multiple machines and buffers. More recently, Fernandez et al. have established a "Just-for-Peak" buffer inventory methodology to reduce the power demand during the peak periods without compromising system throughput for typical manufacturing systems [42]. This work only considers the energy control opportunity during peak periods while neglecting the opportunities during other periods.

For the CHP system, Rong et al. provided a dynamic programming algorithm for unit commitment of CHP systems [43]. Danon et al. studied the possibilities of the implementation of CHP in the wood industry in Serbia [44]. Fawkes and Jacques analyzed the optimum sizing of the investment in CHP plant for beverage-related processing industries [45]. Blok and Turkenburg studied the CO_2 emission reduction by means of industrial CHP in the Netherlands [46]. These studies cannot address the applications for the typical manufacturing systems with multiple machines and buffers.

Motivated by the status quo aforementioned, in this thesis, we will focus on electricity demand response and on-site generation system utilization for typical manufacturing systems toward sustainability to explore the electricity load management for industrial manufacturing customers. Without losing generality, Critical Peak Pricing (CPP) program, a typical demand response program is selected for the purpose of mathematical modeling establishment for the electricity demand response. The optimal production schedule and the critical parameter for the CPP program participation will be identified to minimize the overall cost of the manufacturer (see the details in Chapter 2). For the on-site generation utilization, a CHP system will be considered an alternative energy source for the manufacturing systems. The optimal schedule of production and CHP utilization will be identified under the typical TOU program to minimize the overall cost (see Chapter 3 for details).

2. METHOD I: OPTIMAL PRODUCTION SCHEDULING UNDER CRITICAL PEAK PRICING ELECTRICITY DEMAND RESPONSE PROGRAM FOR SUSTAINABLE MANUFACTURING SYSTEMS

2.1 Motivation and Introduction

In Critical Peak Pricing (CPP) program, very high “peak” prices are assessed for certain hours on those “critical” days [47] (we define those hours as “CPP intervals” in this thesis). As shown in Figure 2, all the time intervals belong to either the CPP intervals, or the regular peak periods during non-CPP intervals, or the off peak periods during non-CPP intervals with different rates. The time horizon along the billing cycle is slotted with a set of intervals with constant duration.

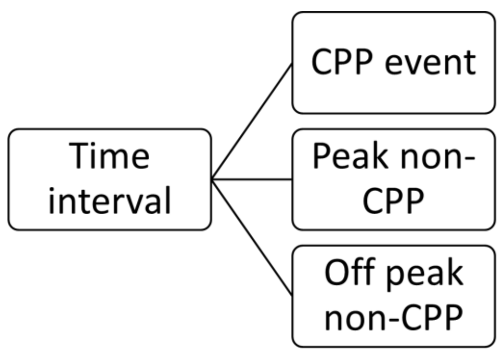

Figure 2. Types of time interval on CPP program

The schedule of the regular peak & off-peak periods during non-CPP intervals are announced in advance. The CPP intervals are usually announced due to some predetermined conditions like temperature forecast and system load on the previous day. In this thesis, we assume that the prediction of the schedule of the CPP intervals for the next month is available and therefore, the detail information of the schedule for all the time intervals and corresponding rates for the next month is assumed to be known to the customers in advance. The program participants need to identify a reservation capacity (kW) when signing the contract with the utilities. The rate for the electricity consumption above the reservation capacity during the CPP intervals is extremely high (~$1/kWh) as an exchange for the lower rates (~$0.09/kWh) on non-CPP intervals [48]. The final electricity bill of the CPP participants mainly includes the electricity consumption charge ($/kWh) during the CPP intervals, peak periods during non-CPP intervals, and off-peak periods during non-CPP intervals as well as the charge of the reservation capacity ($/kW).

It can be intuitively observed that the higher the value of the reservation capacity selected, the less probability of being charged with an extremely high electricity consumption rate during CPP intervals, and more flexibility of production scheduling can be obtained, nevertheless, the cost of the reservation capacity charge will be higher. In contrast, the lower the value of the reservation capacity chosen, although the less the reservation capacity charge will be, the higher the possibility of the electricity consumption charge with an extremely high rate and the less flexibility of the production control will be. Hence, the selection of the reservation capacity has to be carefully modeled and the tradeoff aforementioned has to be taken into consideration to reduce the cost of electricity bill.

The objective of this chapter is to help the CPP participants from industrial sectors identify a cost-effective reservation capacity and by optimal production scheduling aiming at minimizing the overall electricity related cost as well as the potential penalty cost due to the failure of timely fulfillment of target production. A Mixed Integer Nonlinear Programming (MINLP) problem is formulated and an approximate method is used to identify near optimal solutions with reasonable computational costs. Case studies are implemented to illustrate the effectiveness and the efficiency of the proposed methods.

2.2 Proposed Method

A. Mathematical Modeling

We consider a typical production system with N machines and N-1 buffers as shows in Figure 3 where rectangle and circle denote machine and buffer, respectively. Let n be the index for both machines ($\forall n \in \{1, 2, ..., N\}$) and buffers ($\forall n \in \{1, 2, ..., N-1\}$).

Figure 3. A typical production system with N machines and N-1 buffers

The time intervals for the production horizon, i.e., the billing cycle in this research, are indexed by i (i=1,2,…, I) with constant duration T.

The objective of this research is to identify the optimal production schedule and reservation capacity to minimize the total electricity bill cost as well as the potential penalty due to the failure of timely fulfillment of target production. Hence, the objective function can be formulated by (1):

$$\min_{RC, x_{in}} (C_1 + C_2 + C_3 + C_4 + C_5 + C_6) \quad (1)$$

where C_k, $k = 1, 2, ..., 6$, denotes six main cost components, i.e., the electricity consumption cost during CPP intervals when the electricity consumed is higher than the level corresponding to the reservation capacity (C_1), the electricity consumption cost during CPP intervals when the electricity consumed is not higher than the level corresponding to the reservation capacity (C_2), the cost of the electricity consumed in the peak periods during non-CPP intervals (C_3), the cost of the electricity consumed in the off-peak periods during non-CPP intervals (C_4), the cost for the reservation capacity (C_5), and the potential penalty cost (C_6); *RC* is the reservation capacity to be determined; and x_{in} is the binary variable to denote the production scheduling, which takes the value of one if machine *n* is scheduled to keep production during the *i*th interval, and zero otherwise.

For C_1, it can be formulated by (2):

$$C_1 = \sum_{i \in CPP} \{O_i \cdot [R_1 \cdot (\sum_{n=1}^{N} (x_{in} \cdot D_n) - RC) \cdot T + R_2 \cdot RC \cdot T]\} \tag{2}$$

where

CPP: the set of interval *i*'s that belong to CPP intervals.

O_i: binary variable, it takes the value of one if the electricity consumed during CPP interval *i* is above the level corresponding to reservation capacity *RC*, and zero otherwise. It can be formulated by (3):

$$O_i = \begin{cases} 1, & \text{if } \sum_{n=1}^{N} x_{in} \cdot D_n > RC \\ 0, & otherwise \end{cases} \quad \forall i \in CPP \tag{3}$$

R_1: electricity rate ($/kWh) for the electricity consumed above the level corresponding to the reservation capacity *RC* during CPP intervals.

R_2 : electricity rate ($/kWh) for the electricity consumed that is not higher than the level corresponding to the reservation capacity *RC* during CPP intervals.

D_n : rated power (kW) for machine *n*.

For C_2, it can be formulated by (4):

$$C_2 = \sum_{i \in CPP} [(1-O_i) \cdot R_2 \cdot \sum_{n=1}^{N} (x_{in} \cdot D_n) \cdot T] \tag{4}$$

For C_3, it can be formulated by (5):

$$C_3 = \sum_{i \in ONP} [R_3 \cdot (\sum_{n=1}^{N} x_{in} \cdot D_n) \cdot T] \tag{5}$$

where ONP is the set of interval *i*'s that belong to the peak periods during non-CPP intervals, and R_3 is the electricity rate ($/kWh) of the peak periods during non-CPP intervals.

For C_4, it can be formulated by (6):

$$C_4 = \sum_{i \in OFP} [R_4 \cdot (\sum_{n=1}^{N} x_{in} \cdot D_n) \cdot T] \tag{6}$$

where OFP is the set of interval *i*'s that belong to the off-peak periods during non-CPP intervals, and R_4 is the electricity rate ($/kWh) of the off-peak periods during non-CPP intervals.

Note that in the above power-related formulation, for simplicity, we do not consider the random failures of the machines, which may lead to an overestimation of the average power level (the actual average power level during each interval i should be lower when failures are considered). Therefore, our formulation is a progressive maximum estimation of the total cost.

For C_5, it can be formulated by (7):

$$C_5 = R_5 \cdot RC \tag{7}$$

where R_5 is the rate (\$/kW) of reservation capacity RC.

For C_6, it can be formulated by (8):

$$C_6 = R_6 \cdot Q \tag{8}$$

where R_6 is the unit penalty cost (\$/unit) due to the failure of timely completion of the target production, and Q is the number of unfulfilled production that can be formulated by (9):

$$Q = Max(0, A - \sum_{i=1}^{I} x_{iN} \cdot P_N \cdot T \cdot F_N) \tag{9}$$

where P_N is the production rate (units/hour) of machine N; T is the constant duration of time interval i (hour); F_N is the efficiency of machine N; and A is the production target (units) for the horizon.

The constraints are discussed as follows:

1) Buffer capacity constraint is described by (10):

$$
\begin{aligned}
&0 \le B_{in} \le S_n \\
&\forall i \in \{1, 2, ..., I\} \\
&\forall n \in \{1, 2, ..., N-1\}
\end{aligned}
\tag{10}
$$

where B_{in} denotes the contents in buffer *n* at the end of *i*th interval; and S_n is the maximum capacity for buffer *n*.

2) Inventory balance constraint is described by (11):

$$
\begin{aligned}
&B_{in} - x_{in} \cdot T \cdot P_n \cdot F_n + x_{i(n+1)} \cdot T \cdot P_{n+1} \cdot F_{n+1} - B_{(i-1)n} = 0 \\
&\forall i \in \{1, 2, ..., I\} \\
&\forall n \in \{1, 2, ..., N-1\}
\end{aligned}
\tag{11}
$$

Note that B_{0n} denotes the initial contents for buffer *n*.

3) Maximum unfulfilled production constraint is described by (12):

$$
Q \le \varphi \tag{12}
$$

where φ is the allowed maximum amount of the unfulfilled production (units)

4) Target production constraint is described by (13):

$$
\sum_{i=1}^{I} x_{iN} \cdot P_N \cdot T \cdot F_N + \varphi \ge A \tag{13}
$$

5) The constraint of reservation capacity RC is described by (14):

$$0 \le RC \le \sum_{n=1}^{N} D_n \quad (14)$$

By now, we formulate a Mixed Integer Nonlinear Programming (MINLP) with nonlinearities in the objective function (1) and constraints (10)-(14).

B. Solution Technique

In order to solve the proposed MINLP model with a reasonable computational cost, an approximate method is introduced in this section. We first separate the problem into several sub-problems which cover a specific part of the interval i's to reduce the dimension of the problem. After solving all the sub-problems, the obtained solutions of x_{in} are used in the original problem as given conditions to obtain the final solution of RC. Figure 4 shows the flow chart of the approximate method.

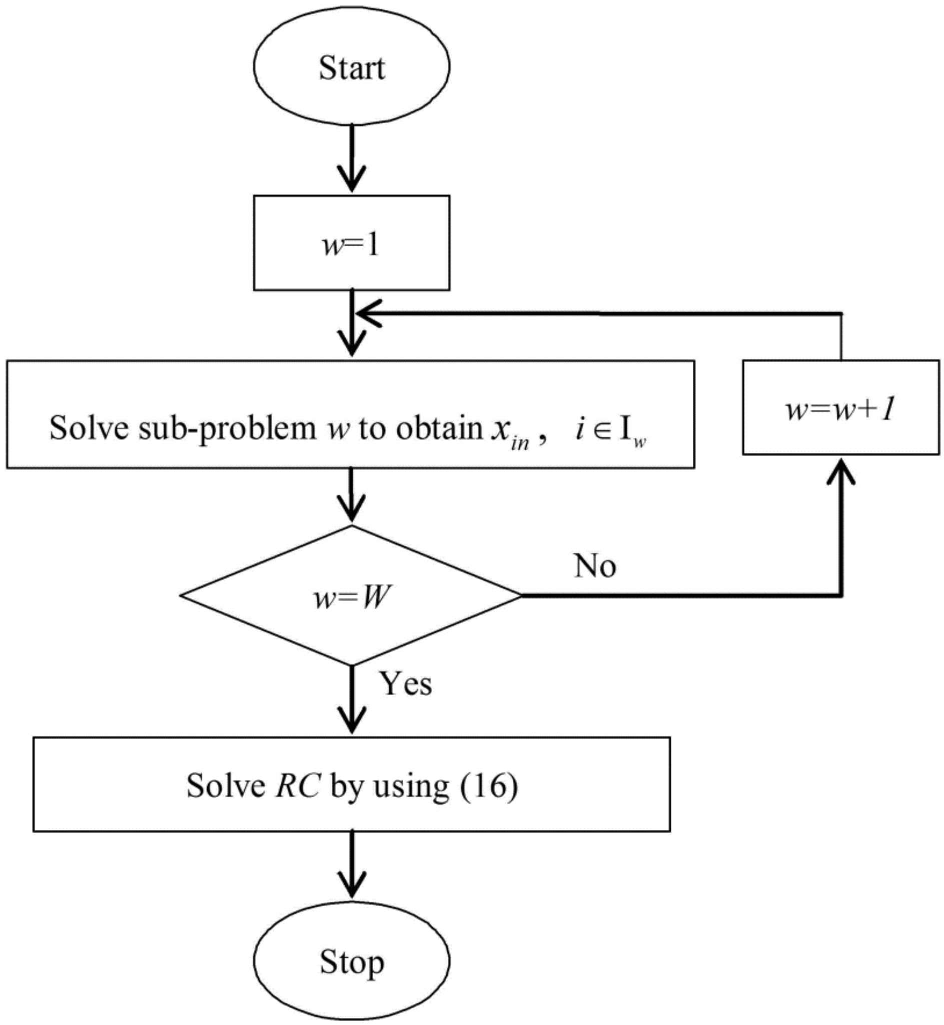

Figure 4. Flow chart of the approximate method

More specifically, let I be the set of the interval i's; I_w be a subset of I with index w (w=1, 2, ... , W) that will be handled by sub-problem w.

The objective function for sub-problem w can be formulated by (15):

$$\min_{\substack{x_{in}, RC_w \\ (i \in I_w)}} (C_1^w + C_2^w + C_3^w + C_4^w + C_5^w + C_6^w) \tag{15}$$

where C_k^w, $k = 1, 2, ..., 6$, $w = 1, 2, ..., W$, denotes the six main cost components for the sub-problem *w,* and RC_w is the corresponding reservation capacity in sub-problem *w*. Assume φ and *A* can be equally separated down into φ_w and A_w in each sub-problem *w* according to the number of interval *i*'s that is covered in the sub-problem *w*, thus the constraints for each sub-problem *w* can be obtained accordingly based on (10)-(14). After solving all the sub-problems, (16) will be formulated with the constraint (14) to solve the reservation capacity *RC*.

$$\min_{RC}[\sum_{k=1}^{6} C_k(x_{in})] \tag{16}$$

It can be seen that both (15) and (16) are MINLP problems. Existing commercial software packages are mature and convenient to address this kind of problem [49]. In this research, GAMS (General Algebraic Modeling System) [50] with the solver LINDO global which employs branch-and-cut methods to separate a Nonlinear Programming (NLP) model down into a list of problems will be used. Thus, given appropriate tolerances, after a finite, though possibly large number of steps a solution provably global optimal to tolerances can be returned [51].

2.3 Case Study

To illustrate the effectiveness of the proposed methods, a five-machine and four-buffer serial production system as shown in Figure 5 is considered. The characteristics of each machine, i.e., efficiency, production rate, and rated power (note that the efficiency and production rate are the real data from our industrial partner, and rated power is assumed); and the assumed parameters of each buffer are shown in Table I and Table II respectively.

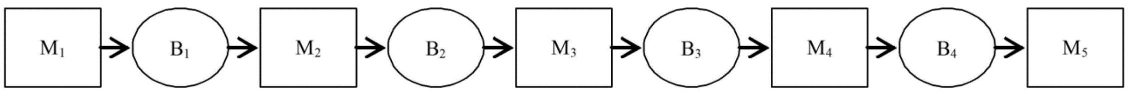

Figure 5. A serial production system with five machines and four buffers

TABLE I. MACHINES CHARACTERISTICS

Machine	Power (kW)	Efficiency	Production Rate (units/hour)
1	14	95.28%	132
2	24	79.58%	122
3	14	86.06%	127
4	15	88.85%	123
5	25	85.60%	124

TABLE II. PARAMETERS OF THE BUFFERS

Buffer	Initial Inventory (units)	Maximum Capacity (units)
1	32	142
2	30	132
3	40	137
4	30	133

In this case, we assume that there are four weeks in a billing cycle, i.e., one month. For each week, it contains five working days with eight working hours per day (9:00am-5:00pm). The duration T of time interval i in this case is set to be one hour. The occurrence of the CPP intervals with six-hour duration (11:00am-5:00pm) is assumed to be known. The schedule of the regular peak/off-peak periods during non-CPP intervals is from the rate schedule of San Diego Gas & Electric (SDG&E) [52]. The schedule for the whole billing cycle is shown in Table III.

TABLE III. MONTHLY SCHEDULE

Week(w)	Time	Monday	Tuesday	Wednesday	Thursday	Friday
1	09:00am-11:00am	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*
	11:00am-05:00pm	*Peak NCPP*	*CPP*	*Peak NCPP*	*Peak NCPP*	*Peak NCPP*
2	09:00am-11:00am	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*
	11:00am-05:00pm	*CPP*	*Peak NCPP*	*Peak NCPP*	*Peak NCPP*	*Peak NCPP*
3	09:00am-11:00am	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*
	11:00am-05:00pm	*Peak NCPP*	*Peak NCPP*	*Peak NCPP*	*Peak NCPP*	*CPP*
4	09:00am-11:00am	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*	*Off P NCPP*
	11:00am-05:00pm	*Peak NCPP*	*Peak NCPP*	*CPP*	*Peak NCPP*	*Peak NCPP*

Off P NCPP: Off Peak Periods during Non-CPP intervals.
CPP: CPP intervals
Peak NCPP: Peak periods during non-CPP intervals

The different electricity related rates from the rate schedule of SDG&E [52] and the assumed penalty rate considered in the case are shown in Table IV. The assumed weekly production target and the allowed maximum unfulfilled production of each week are shown in

Table V.

TABLE IV. ELECTRICITY RELATED RATES AND UNIT PENALTY COST

Rate	Unit	Cost
R_1	$/kWh	$1.06575
R_2	$/kWh	$0.09071
R_3	$/kWh	$0.09071
R_4	$/kWh	$0.07246
R_5	$/kW	$6.44000
R_6	$/units	$15.00000

TABLE V. WEEKLY TARGET PRODUCTION AND ALLOWED MAXIMUM UNFULFILLED PRODUCTION

Week(w)	A_w	φ_w
1	3689	200
2	3680	200
3	3650	200
4	3680	200
Total	14699	800

Specifically, we divide the problem into four sub-problems corresponding to four production weeks in the case study. The reservation capacity and the optimal production schedule are identified by using GAMS with Solver LINDO following the procedure to solve the proposed MINLP formulation as shown in Figure 4. With the identified optimal reservation capacity, 92kW in this case, and the corresponding optimal production schedule, the power demand curve throughout the whole billing cycle and the throughput of each week are illustrated in Figure 6 and Table VI respectively. The simulation model of the manufacturing system as shown in Figure 6 is also established by ProModel®, a simulation-based decision-making tool for discrete event system developed by ProModel, Inc [53]. It can be used to improve the performance of manufacturing, warehousing, and other operational and strategic situations of the enterprise. The statistical evaluation of the proposed method is implemented. 95% confidence interval of the throughput for each week is obtained as shown in Table VII.

TABLE VI. WEEKLY PRODUCTION

Week(w)	A_w	Scheduled Production	Q_w
1	3689	3715	0
2	3680	3715	0
3	3650	3715	0
4	3680	3715	0
Total	14699	14860	0

TABLE VII. SCHEDULED AND SIMULATED RESULTS OF WEEKLY PRODUCTION

Week(w)	Scheduled Production	95% C.I. by Simulation
1	3715	(3701, 3764)
2	3715	(3700, 3763)
3	3715	(3700, 3763)
4	3715	(3697, 3760)

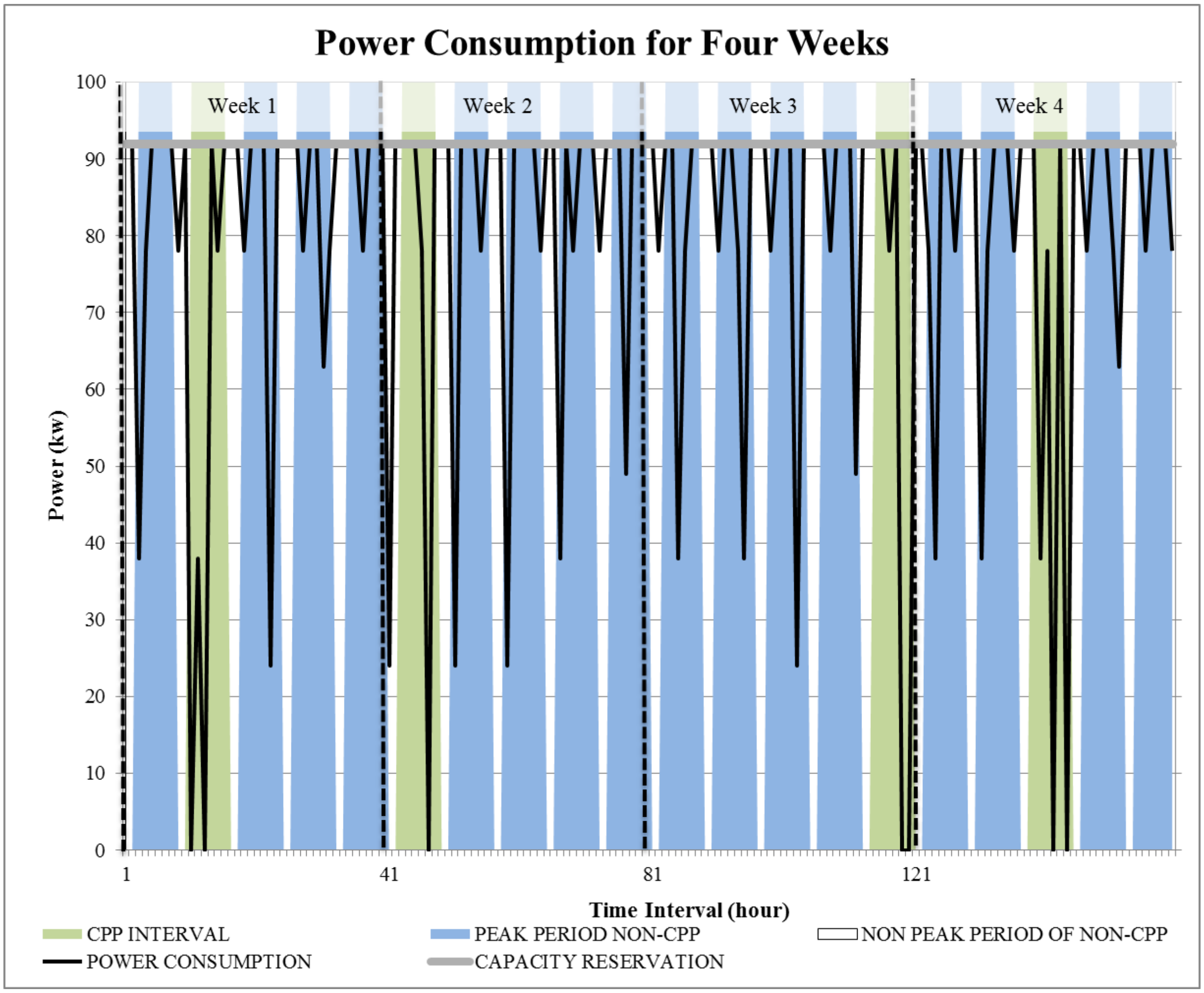

Figure 6. Capacity reservation and power consumption of the billing cycle

In addition, two other methods that can determine the reservation capacity in CPP program are considered for comparison. The first one is a simple method, i.e., set zero as the reservation capacity. The second one is an expert rule, i.e., set half of the maximum demand as the reservation capacity (defaulted method by SDG&E if customers do not provide any selection). The corresponding costs and the cost obtained from the proposed method are compared in Figure 7 and Table VIII. It can be seen that the overall cost obtained from the proposed method is about 31.42% and 11.04% lower than the ones obtained from the simple method and the expert rule respectively.

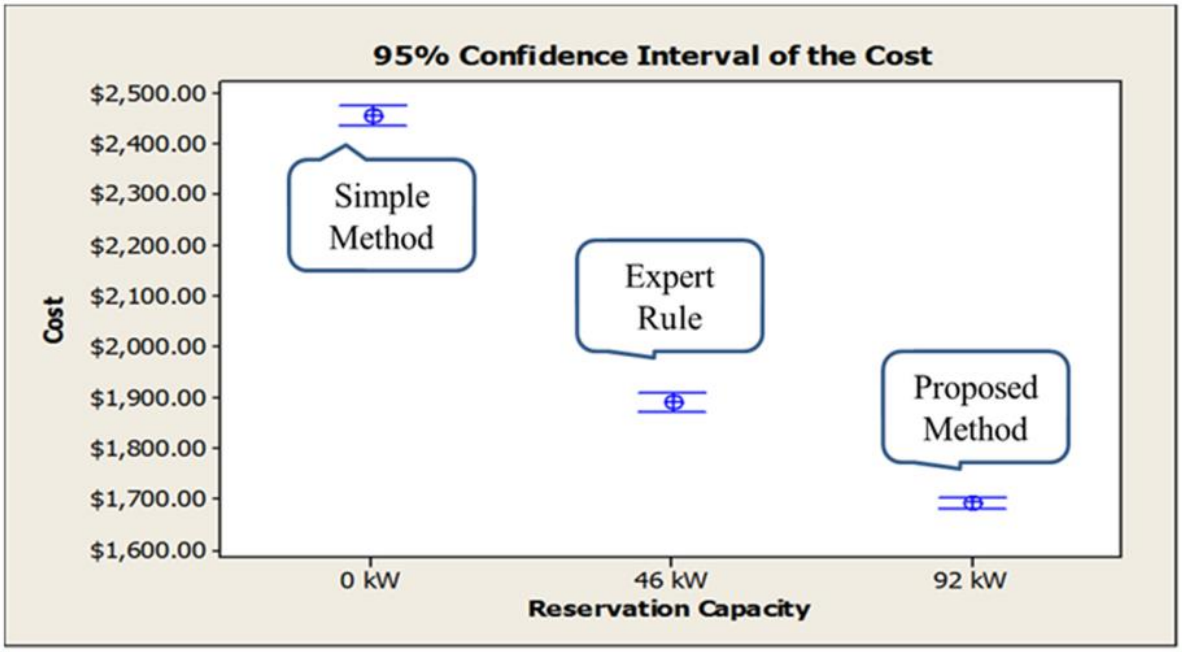

Figure 7. Comparison of the 95% confidence interval of the cost between the proposed method and two other methods

TABLE VIII. COST COMPARISON BETWEEN THE PROPOSED METHOD AND TWO OTHER METHODS

Method Type	Simple Method	Expert Rule	Proposed Method
Cost Components	RC=0kW	RC=46kW	***RC*=92kW**
C_1	$ 1,492.05	$ 542.47	$ 0
C_2	$ 0	$ 84.27	$ 126.99
C_3	$ 706.09	$ 716.06	$ 707.36
C_4	$ 259.70	$ 255.64	$ 258.68
C_5	$ 0	$ 296.24	$ 592.48
C_6	$ 0	$ 0	$ 0
Total Cost	$ 2,457.83	$ 1,894.68	$ 1,685.51
Savings	31.42%	11.04%	

2.4 Conclusions

This chapter proposes a methodology to help the manufacturing enterprises who participate in the Critical Peak Pricing (CPP) Program, a typical electricity demand response program, identify the reservation capacity by optimal production scheduling to minimize the overall operation cost, i.e., electricity consumption related cost and the penalty cost due to the non-fulfillment of the target production. A Mixed Integer Nonlinear Programming (MINLP) is used to formulate the problem and approximate method is used to obtain a near optimal solution. The results of the case study show that a cost reduction of 31.42% and 11.04% can be achieved for a billing cycle compared with the simple method and the expert rule respectively.

3. METHOD II: OPTIMAL PRODUCTION SCHEDULING AND ON-SITE GENERATION UTILIZATION FOR SUSTAINABLE MANUFACTURING SYSTEMS

3.1 Motivation and Introduction

Combined Heat and Power (CHP) is a highly efficient integrated energy system that simultaneously produces electricity and heat from a fuel source [20]. High efficiency and less GHG emission are the main benefits. Figure 8 shows the magnitude of reduced CO_2 emissions of a five-megawatt (MW) natural gas-fired CHP system compared with separate heat and power generation system [21]. In addition, it is also expected that the energy efficiency can be improved by 35% compared with traditional separated generation system as shown in Figure 9 [54].

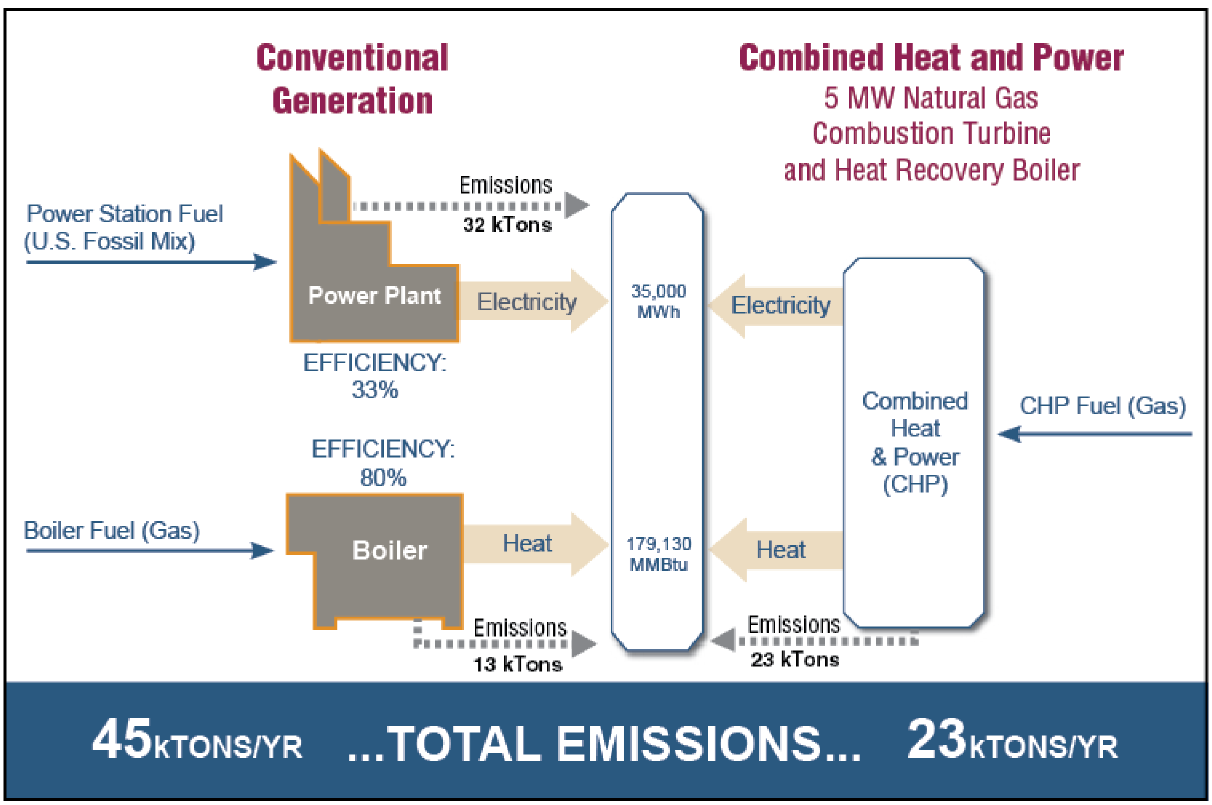

Figure 8. CO2 emissions comparison between CHP system and separated energy generation systems (source: http://www.epa.gov/chp/basic/environmental.html)

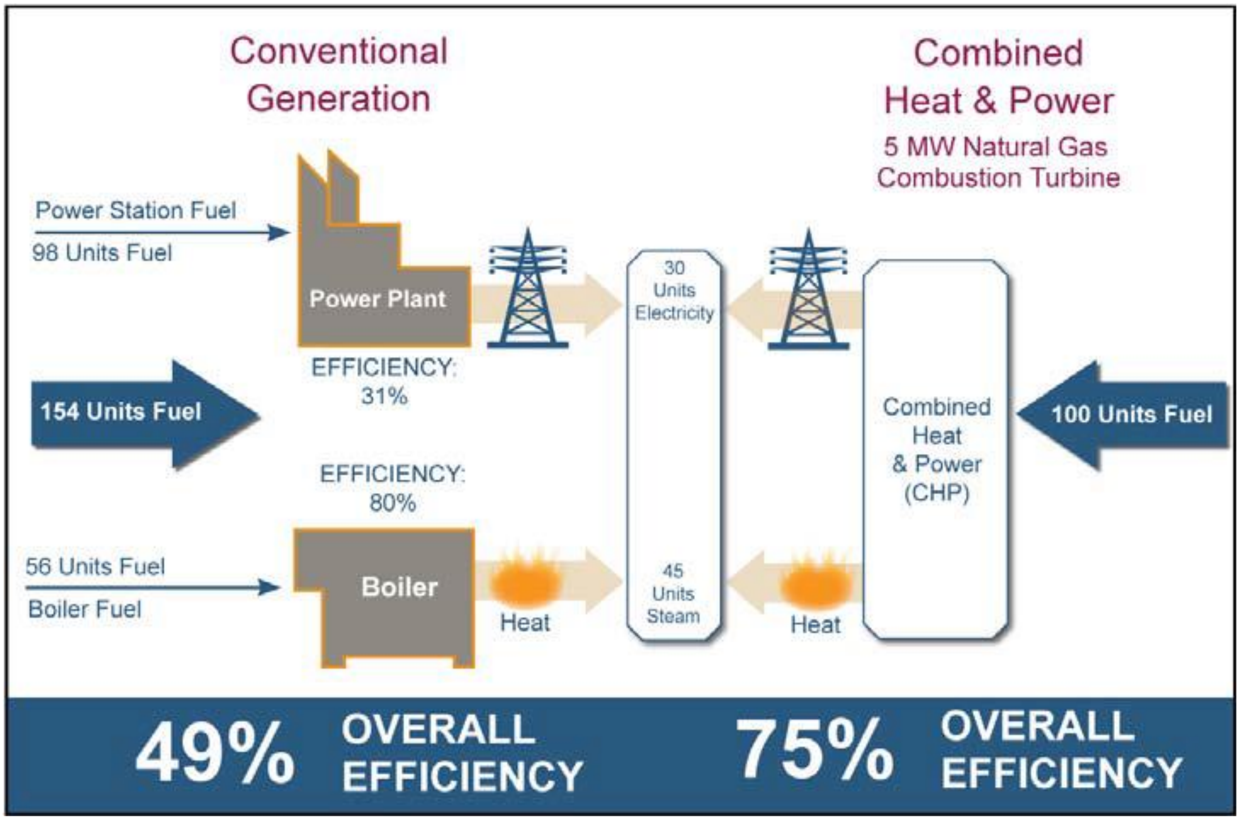

Figure 9. Energy efficiency comparison between CHP system and separate heat and power systems (source: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf)

This chapter presents a methodology to optimize the production schedule of a typical manufacturing system with multiple machines and buffers utilizing on-site CHP system under a Time-of-Use (TOU) schedule. In TOU program, there are three different types of periods with different rates, i.e., off-peak period, partial-peak period, and peak period (see Figure 10). The electricity rates for each hour are known in advance and are fixed for each billing cycle. The rates during peak-periods are higher than partial-peak and off-peak periods. Therefore, the customer needs to carefully schedule their activities in order to reduce the electricity billing cost.

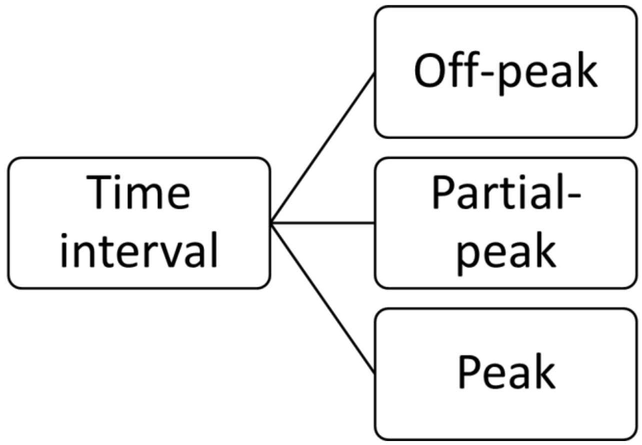

Figure 10. Types of time interval on TOU program

The objective of this chapter is to identify the optimal schedule of production and CHP system to minimize the overall cost for the manufacturer. Both electricity bill-related cost and CHP-related cost items are considered. Mixed Integer Nonlinear Programming (MINLP) formulation is used to create the mathematical model. A numerical case study is used to illustrate the effectiveness of the proposed method.

3.2 Proposed Method

In this section, we consider the same typical manufacturing system with *N* machines and *N*-1 buffers as shown in Figure 3 and an equipped CHP system as shown in Figure 11. The natural gas is used as the fuel to be combusted and thus and electricity and the heat can be generated simultaneously. An auxiliary boiler is also included to provide the heat if necessary. Assume the production horizon, i.e., the billing cycle in this research, are slotted with the intervals with equal duration *T*. Same as the Chapter 2, let *i* (*i*=1,2,…, *I*) be the index of those slotted intervals.

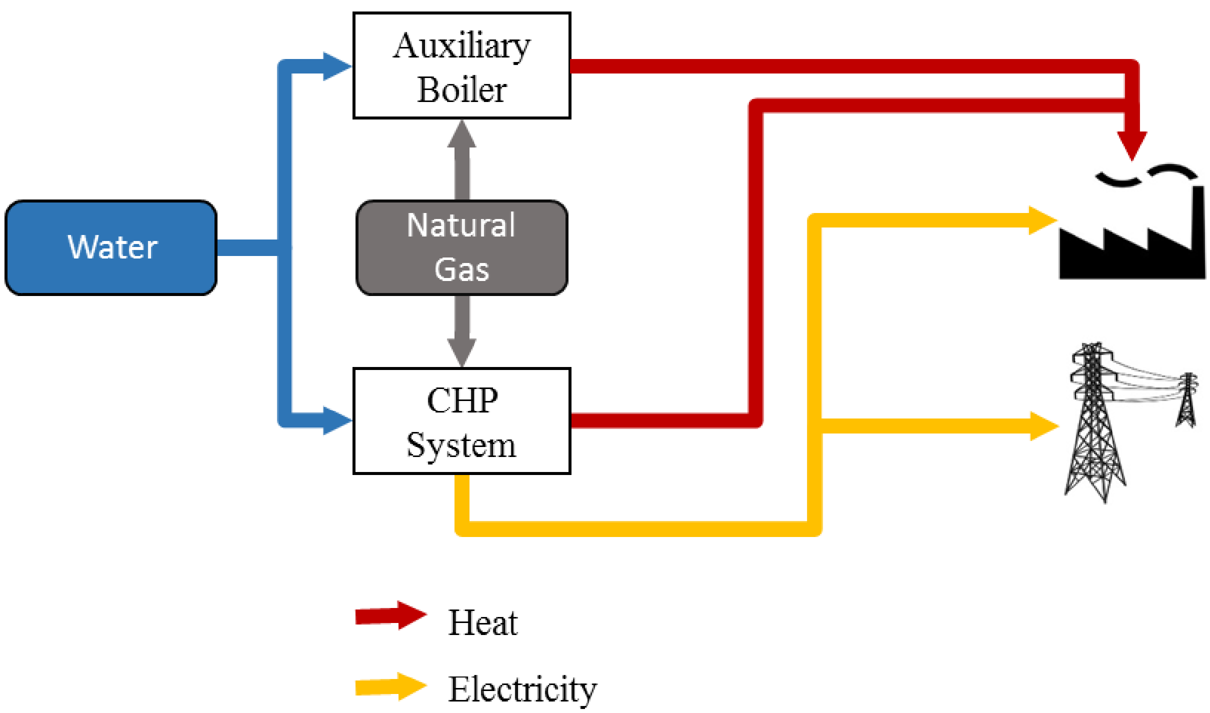

Figure 11. CHP system with an auxiliary boiler

The objective is to find the optimal schedule for production and CHP system to minimize the overall cost. Hence, the objective function can by formulated by (17):

$$\min_{x_{in}, y_i, z_i, O_i, HA_i,} (C_E + C_{CHP}) \tag{17}$$

where C_E is the electricity related cost; C_{CHP} is the CHP system related cost; x_{in} is the binary decision variable to denote the production scheduling, which takes the value of one if machine *n* is scheduled to keep production during the *i*th interval, and zero otherwise; y_i is a binary decision variable to denote the action adopted by the CHP system at the beginning of interval *i*, which takes the value of one if the decision is to keep CHP on and zero otherwise; O_i is a continuous variable which takes a value between zero and one to denote the percentage that the electricity consumed by the production system is supplied by the CHP system; z_i is a binary decision variable to denote if the auxiliary boiler is on or not, which takes the value of one if the auxiliary boiler is on during the *i*th interval, and zero otherwise; and HA_i is the variable output heat provided by the auxiliary boiler during the *i*th interval (kWh).

C_E includes the electricity consumption charges during different intervals (peak, partial peak, and off peak), electricity demand charge for the whole billing cycle, and the income due to the sales of the electricity generated from CHP system to the utility. It can be formulated by (18):

$$\begin{aligned} C_E = & \sum_{i \in ONP} \{(1-O_i) \cdot R_{ONP} \cdot (\sum_{n=1}^{N} x_{in} \cdot D_n \cdot T)\} + \sum_{i \in PAP} \{(1-O_i) \cdot R_{PAP} \cdot (\sum_{n=1}^{N} x_{in} \cdot D_n \cdot T)\} \\ & + \sum_{i \in OFP} \{(1-O_i) \cdot R_{OFP} \cdot (\sum_{n=1}^{N} x_{in} \cdot D_n \cdot T)\} + R_D \cdot \max_i (\sum_{n=1}^{N} x_{in} \cdot D_n) \\ & - \sum_i \{R_{SU} \cdot y_i \cdot \max((EC \cdot T - O_i \cdot \sum_{n=1}^{N} x_{in} \cdot D_n \cdot T), 0)\} \end{aligned} \tag{18}$$

where ONP is the set of interval *i*'s that belong to peak periods; PAP is the set of interval *i*'s that belong to partial peak periods; OFP is the set of interval i's that belong to off peak periods; D_n is rated power (kW) of machine n; R_{ONP} is the electricity consumption rate ($/kWh) of peak periods; R_{PAP} is the electricity consumption rate ($/kWh) of partial peak periods; R_{OFP} is the electricity consumption rate ($/kWh) of off peak periods; R_{SU} is the rate of the electricity that can be sold back to the utility company ($/kWh); R_D is the demand charge rate ($/kW); EC is capacity of electricity produced by CHP system (kW).

C_{CHP} includes CHP system operation & maintenance cost, CHP system setup cost, CHP system fuel usage cost, auxiliary boiler fuel usage cost, and penalty cost of exceeded (wasted) heat. It can be formulated by (19):

$$\begin{aligned} C_{CHP} = & \sum_i \{ \frac{EC \cdot T + EC \cdot T / P2H}{FC \cdot GE} R_{NG} \cdot y_i \} + \sum_i R_S \cdot \max\left(y_i - y_{i-1}, 0\right) \\ & + \sum_i R_{NG} \cdot z_i \cdot \frac{HA_i}{FA \cdot GE} + \sum_i R_{OM} \cdot EC \cdot T \cdot y_i + \sum_i HE_i \cdot R_P \end{aligned} \tag{19}$$

where $P2H$ is power to heat ratio of CHP (no unit), and can be denoted by $P2H = EC / HC$; HC is the capacity of heat provided by the CHP system (kW); GE is the calorific value of the natural gas (kWh/m^3); FC is the efficiency of the CHP system (%); R_S is the setup cost ($) of the CHP system; R_{NG} is the cost of natural gas ($/m^3); R_{OM} is the rate of the operation and maintenance cost of the CHP system ($/kWh); FA is the efficiency of the auxiliary boiler (%); HE_i is the exceeded heat (kWh) during interval i which can be denoted as $HE_i = y_i \cdot \frac{EC \cdot T}{P2H} + z_i \cdot HA_i - HD$, where HD is the heat demand (assume constant); R_P is the penalty rate due to the waste heat ($/kWh).

The constraints are discussed as follows:

1) The maximum CHP electricity supply is described by (20):

$$O_i \cdot (\sum_{n=1}^{N} x_{in} \cdot D_n) \le EC \quad \forall i \in \{1,2,...,I\} \tag{20}$$

2) Inventory balance constraint is described by (21):

$$B_{in} - x_{in} \cdot P_n \cdot F_n + x_{i(n+1)} \cdot P_{n+1} \cdot F_{n+1} - B_{(i-1)n} = 0 \quad \forall i \in \{1,2,...,I\} \quad \forall n \in \{1,2,...,N-1\} \tag{21}$$

where B_{in} denotes the contents in buffer n at the end of ith interval; B_{0n} denotes the initial contents for buffer n; P_n is the production rate of the machine n (units/h); F_n is the efficiency (%) of the machine n.

3) Target production constraint is described by (22):

$$\sum_{i=1}^{I} x_{iN} \cdot P_N \cdot F_N \ge A \tag{22}$$

where A is the production target (units) for the horizon.

4) Buffer capacity constraint is described by (23):

$$0 \le B_{in} \le S_n$$
$$\forall i \in \{1,2,...,I\} \tag{23}$$
$$\forall n \in \{1,2,...,N-1\}$$

where S_n is the maximum capacity for buffer *n*.

5) Maximum and minimum heat produced by the auxiliary boiler (24):

$$z_i \cdot H_{\min} \le HA_i \le z_i \cdot H_{\max} \tag{24}$$

where $H_{\min}$ is the constant minimum nominal heat produced by the auxiliary boiler (kWh); and $H_{\max}$ is the constant maximum nominal heat produced by the auxiliary boiler (kWh).

6) The minimum up and off time can be described by (25):

$$y_i = \begin{cases} 1, & if \quad 1 \le U_{i-1} < U_{up} \\ 0, & if \quad -1 \ge U_{i-1} > -U_{off} \end{cases} \tag{25}$$

where U_{up} is minimum up time (the number of interval *i*'s) of the CHP system after start-up; U_{off} is minimum off time of the CHP system after shut-down; U_i is the consecutive up/off time of the CHP system at the beginning of interval *i*. It takes positive value to denote the consecutive up-time and negative value to denote the consecutive off-time. It can be formulated by (26):

$$U_i = \begin{cases} \max(U_{i-1},0)+1, & \text{if} \quad y_{i-1}=1 \\ \min(U_{i-1},0)-1, & \text{if} \quad y_{i-1}=0 \end{cases} \tag{26}$$

The initial condition is assumed to be $U_1 = U_{off}$. It is used to ensure that CHP system can start at the first interval.

By now, we can see that a Mixed Non-Linear Integer Programming (MINLP) problem is formulated. We use the similar approximate method we use in Chapter 2 to solve the proposed MINLP model with a reasonable computational cost. We separate the problem into several sub-problems which cover a specific part of the interval *i*'s to reduce the dimension of the problem. Using the same notations, let I be the set of the interval *i*'s; I_w be a subset of I with index *w* (*w*=1, 2, ... , *W*) that will be handled by sub-problem *w*. The objective function for sub-problem *w* can be formulated by (27):

$$\min_{\substack{O_i, z_i, y_i, FA_i, x_{in} \\ (i \in \mathrm{I}_w)}} (C_E^w + C_{CHP}^w) \tag{27}$$

where C_E^w and C_{CHP}^w denote the electricity related cost and CHP related cost for the sub-problem *w*. Similarly, assume *A* can be equally separated down into A_w in each sub-problem *w* according to the number of interval *i*'s that is covered in the sub-problem *w*, thus the constraints for each sub-problem *w* can be obtained accordingly based on (20)-(25).

It can be seen that (27) is a MINLP problem. Same as before, commercial software packages GAMS© (General Algebraic Modeling System) with the solver LINDO global will be used to obtain a solution provably global optimal to tolerances.

3.3 Case Study

To illustrate the effectiveness of the proposed method, a five-machine and four-buffer typical manufacturing system incorporated with a CHP system using natural gas and an auxiliary boiler are studied as shown in Figure 12. The assumed parameters of each machine, i.e., efficiency, production rate, and rated power, and the assumed parameters of each buffer are shown in Tables IX and X, respectively. The parameters of the CHP system and the auxiliary boiler, i.e., the efficiency of CHP, the power to heat ratio, the energy capacity of natural gas, are assumed by referring to literature [55]. Those parameters and the heat demand are shown in Table XI.

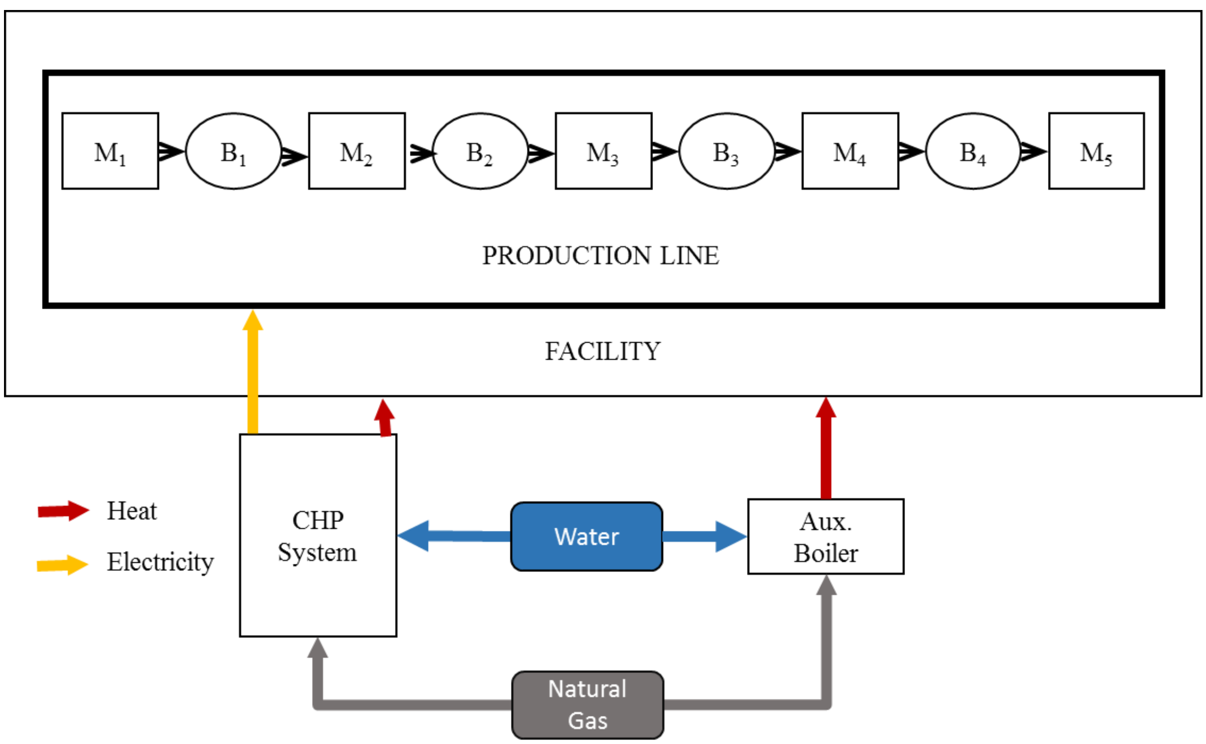

Figure 12. A serial production system with five machines and four buffers connected to a CHP system with an auxiliary boiler

TABLE IX. MACHINES CHARACTERISTICS

Machine	Power (kW)	Efficiency	Production Rate (units/hour)
1	14	95.28%	132
2	24	79.58%	122
3	14	86.06%	127
4	15	88.85%	123
5	25	85.60%	124

TABLE X. PARAMETERS OF THE BUFFERS

Buffer	Initial Inventory (units)	Maximum Capacity (units)
1	32	142
2	30	132
3	40	137
4	30	133

TABLE XI. CHP AND AUXILIARY BOILER PARAMETERS, ENERGY CAPACITY OF NATURAL GAS AND HEAT DEMAND

GE	kWh/m^3	9.649
H_{min}	kWh	30.000
H_{max}	kWh	150.000
HD	kWh	140.000
FA	%	82.000
FC	%	80.000
EC	kW	60.000
HC	kW	92.300
$P2H$	No unit	0.650

In this case, we assume that there are four weeks in a billing cycle, i.e., one month. For each week, it contains five working days with eight working hours per day (7:00am-3:00pm). The duration T of time interval i in this case is set to be one hour. The peak, partial-peak and off-peak periods are known and fixed for every day. Figure 13 shows the time distribution used for this case study [56].

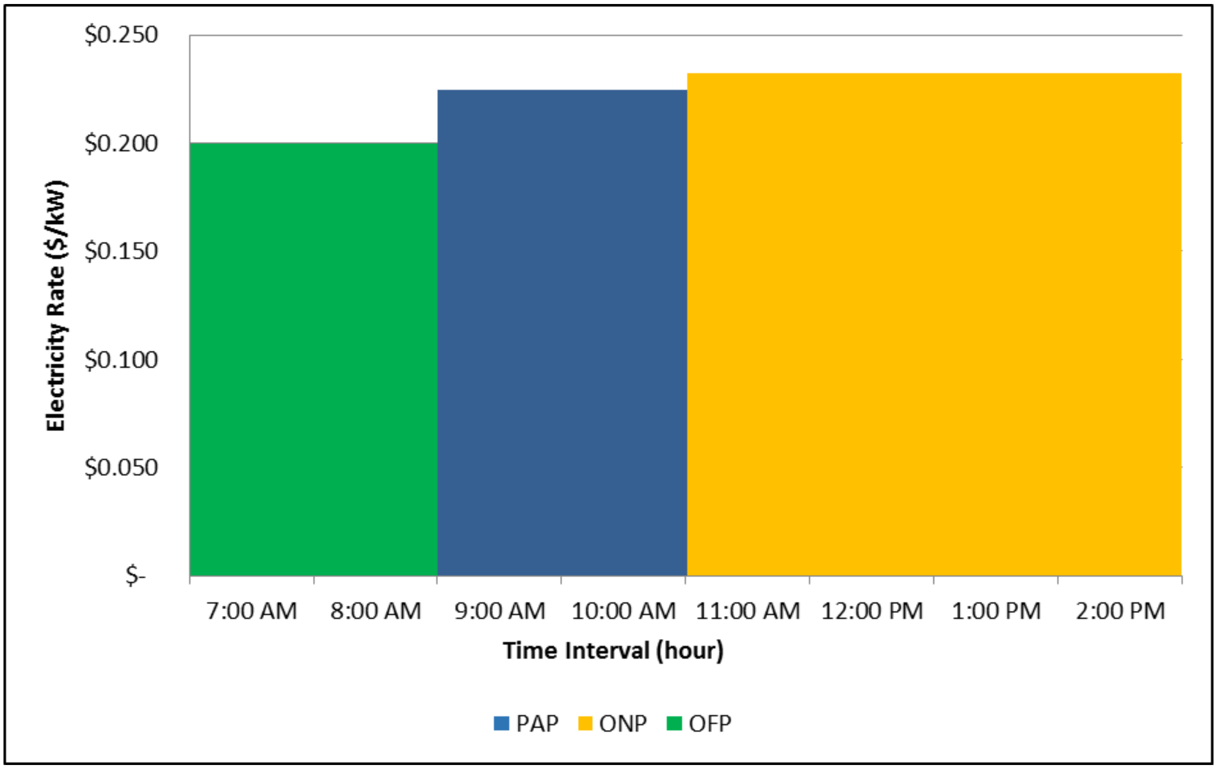

Figure 13. Daily hourly rate under TOU program

The electricity rates for different periods from the schedule of utility company [56], the assumed rate of the electricity that is sold back to the utility, the assumed CHP setup cost, the cost of natural gas [57], the assumed cost of maintenance and operations of the CHP [54], and the assumed penalty of exceeded heat demand considered in the case are shown in Table XII. The assumed weekly production target is shown in Table XIII.

TABLE XII. ELECTRICITY RELATED RATES, DEMAND CHARGE, CHP SETUP COST, NATURAL GAS COST AND EXCEEDED HEAT PENALTY COST

Rate	Unit	Cost
R_{ONP}	\$/kWh	\$0.23100
R_{PAP}	\$/kWh	\$0.22400
R_{OFP}	\$/kWh	\$0.20000
R_{SU}	\$/kWh	\$0.08103
R_S	\$/Setup	\$15.00000
R_D	\$/kW	\$13.34000
R_{NG}	\$/m^3	\$0.17300
R_{OM}	\$/kWh	\$0.04000
R_P	\$/kWh	\$3.00000

TABLE XIII. WEEKLY TARGET PRODUCTION

Week(w)	A_w
1	3,800
2	3,750
3	3,700
4	3,820
Total	15,070

Specifically, we divide the problem into four sub-problems corresponding to four production weeks in the case study. The optimal schedule for production and CHP system are identified by using GAMS© with Solver LINDO following the procedure to solve the proposed MINLP formulation. With the optimal schedule of production and CHP system utilization, the power demand curve and the heat consumption of the whole billing cycle are illustrated in Figure 14 and 16 15 respectively. The simulation model of the production system is also established. The obtained optimal schedule of production system and CHP energy supply are incorporated to obtain a statistical result. The calculated weekly throughput and the 95% confidence intervals of the throughput based on simulation are shown in Table XIV.

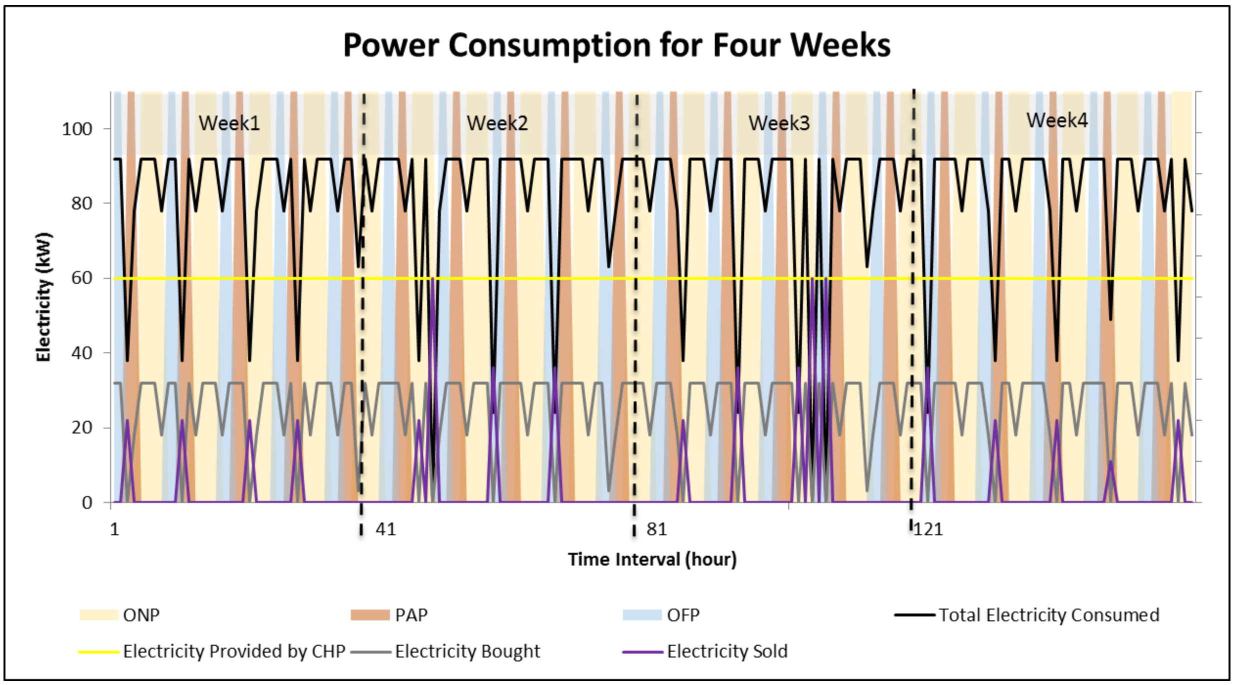

Figure 14. Power consumption and CHP usage of the billing cycle

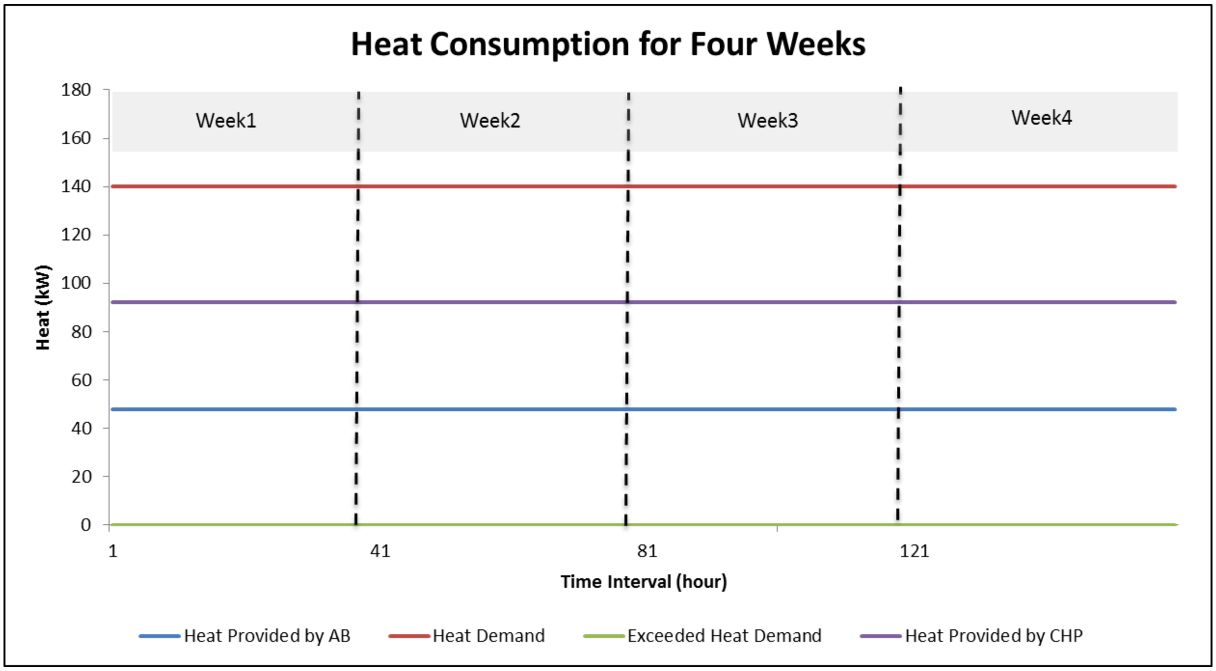

Figure 15. Heat demand and heat generated from CHP and auxiliary boiler

TABLE XIV. WEEKLY SCHEDULED PRODUCTION

Week(w)	Scheduled Production	95% C.I. by Simulation
1	3821	(3806, 3871)
2	3821	(3805, 3870)
3	3715	(3699, 3762)
4	3821	(3802, 3867)
Total	15178	(15113, 15369)

In addition, the situation without deploying CHP system is also examined for cost comparison. It is assumed that 100% of the heat demand is satisfied by the auxiliary boiler. The power consumption of the billing cycle is shown in Figure 16. The corresponding costs and the cost obtained from the proposed method are compared in Table XV and Figure 17. It can be seen that the overall cost obtained from the proposed method is about 29.91% lower than the situation that CHP system is not used.

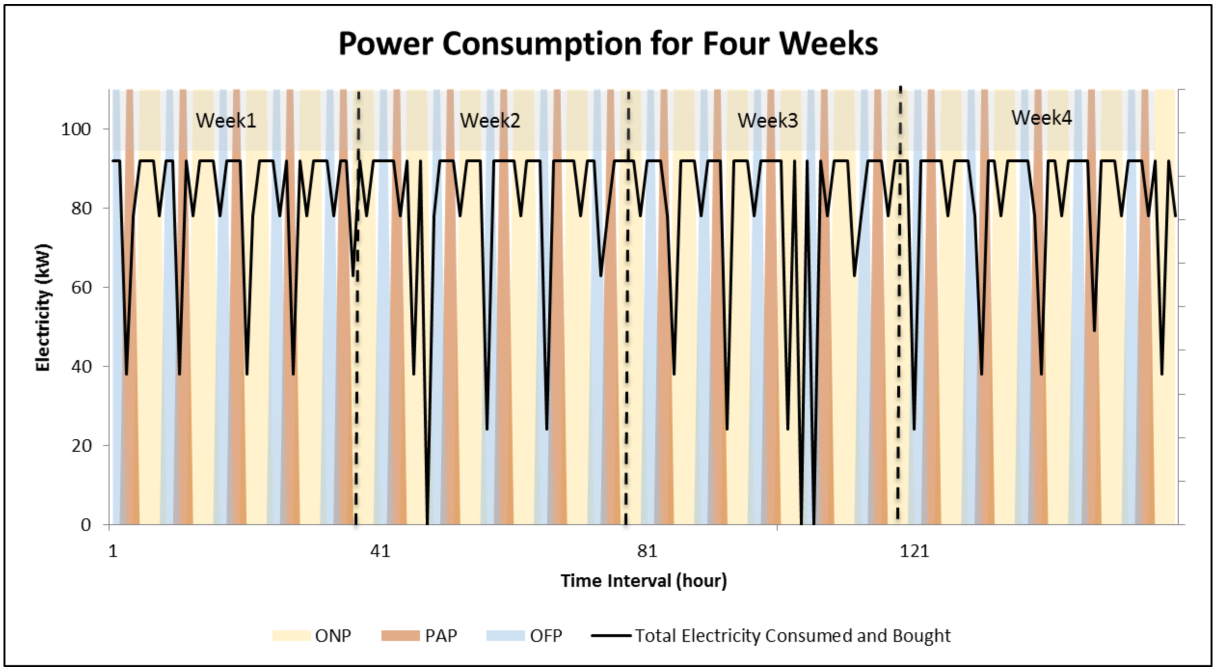

Figure 16. Power consumption of the billing cycle without CHP system.

TABLE XV. COST COMPARISON BETWEEN THE PROPOSED METHOD AND TOU WITHOUT CHP

Cost Components	***CHP***	*NO CHP*
Electricity Bill Cost	$2,122,.078	$4,122.572
CHP Cost	$943.844	
Auxiliary Boiler Cost	$166.846	$489.777
Total Cost	$3,232.768	$4,612.349
Savings (%)	29.91%	
Savings ($)	$1,379.58	
Estimated Annual Savings	$16,554.97	

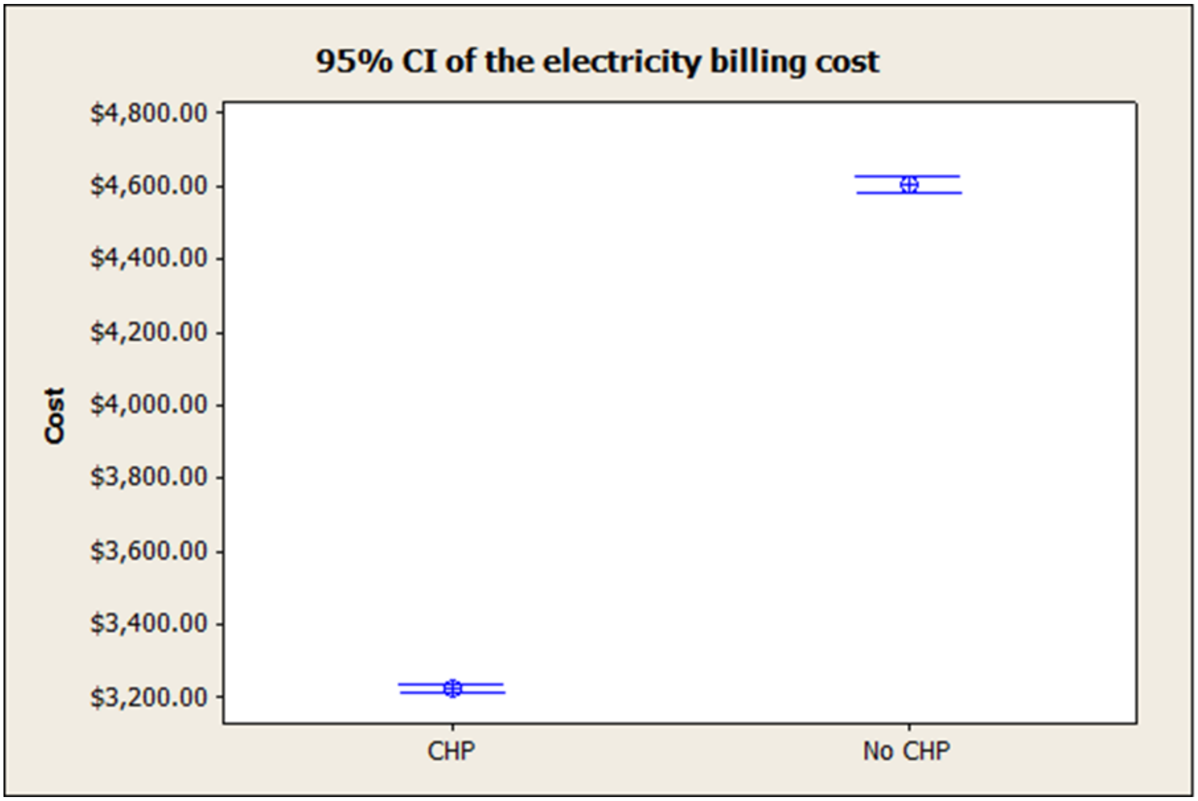

Figure 17. Comparison of the 95% confidence interval of the cost between proposed method and the optimal machine scheduling under Time of Use method.

Finally, the payback analysis for deploying CHP system in the facility is conducted as shown in Table XVI. The capital cost of CHP system includes both installation cost and purchasing cost. It can vary from 430 to 6,500 $/kW depending on the technology of the selected CHP system [54]. In this analysis, we select $1,300/kW based on the analysis from literature [55]. Thus, the CHP capital cost is $78,000. The annual savings is based on the results of our case study of one month. By using the data aforementioned, the simple payback is 4.71 years.

TABLE XVI. PAYBACK ANALYSIS FOR CHP SYSTEM BASED ON CASE STUDY

	Units	CHP Characteristics
Annual Savings	$	$16,554.97
CHP Capital Cost	$	$78,000.00
Payback	Years	**4.71 years**

3.4 Conclusions

This chapter considers the utilization of on-site generation technology for the customer side electricity load management. We propose a mathematical model to optimally schedule the production and CHP system to minimize the overall cost. A Mixed Integer Nonlinear Programming (MINLP) is used to formulate the problem and an approximate method is used to obtain a near optimal solution. The results of the case study show that a cost reduction of 29.91% can be achieved by using the proposed methodology, compared to traditional separated generation systems. The payback analysis based on the given case is also conducted, which shows a promising result.

4. CONCLUSIONS AND FUTURE WORK

This thesis focuses on the studies of customer-side electricity load management for the typical manufacturing systems. Two methodologies, electricity demand response implementation and on-site generation utilization are investigated. The mathematical models for the two methodologies are established using Mixed Integer Nonlinear Programming. The approximate technology is used to obtain the near optimal solution with a reasonable computational cost.

For the electricity demand response implementation, the optimal production schedule and corresponding capacity reservation under CPP program are identified by minimizing the overall cost. The results of the case study illustrate that the cost reduction of 31.42% and 11.04% can be achieved for a billing cycle compared with the use of simple method and the expert rule to identify reservation capacity, respectively. For the on-site generation utilization, the optimal schedules of the manufacturing system and CHP system are obtained by minimizing both electricity related cost and CHP operation cost. The results of the case study demonstrate that about 29.91% cost savings can be achieve compared to the system without using on-site generation technology.

The research in this thesis represents an initial exploration on the academic investigations on the customer side electricity load management for the industrial manufacturing customers. The result illustrates the feasibility of the implementation of load management in manufacturing sector. It also shows promising potential of the proposed methodologies that can be applied in this area.

In the future, the uncertainties of the occurrence of the critical peak periods need be incorporated into the model based on some probability laws. The random failures of the machines which may lead to the lower actual average power during each interval can also be considered in the formulation to make the results more accurate. In addition, the application of other renewable energy sources for the manufacturing system may be another further research direction.

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