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Demand Response Program in Singapore's Wholesale Electricity Market

Shengfeng Zhou, Zhen Shu, Yue Gao, Hoay Beng Gooi, Shuaixun Chen and Kelvin Tan

***Abstract*-- Singapore is going to implement a demand response (DR) program to further enhance the efficiency and competitiveness of its electricity market. This paper aims to provide an in-depth investigation of this DR program which features demand side bidding and incentive payments. First, the current market clearing model (MCM) of Singapore's existing wholesale market, which has no demand side bidding, is introduced. A mathematical model of the MCM is formulated to explain and solve the current market clearing process, where the energy and ancillary services are settled simultaneously through a form of auction pricing. Second, the mechanism of how the demand side bidding is incorporated into the current MCM is explained, with an emphasis on the demand side offer and the newly introduced constraints. A modified MCM with DR is then formulated. Third, the incentive payment mechanism intended to promote DR participation is elaborated. Numerical analysis is performed to demonstrate how the current MCM and MCM with DR work, as well as how the incentive payment is settled. Various numerical case studies are carried out to discuss the economic benefits from participating in the DR program.**

***Index Terms*-- Singapore electricity market, market clearing model (MCM), market clearing price (MCP), demand response (DR), incentive payment, linear programming (LP).**

NOMENCLATURE

Throughout this paper, the superscripts n = *1*, *2* and *3* are used to denote the three main products traded in Singapore's wholesale electricity market - energy, reserve and regulation, respectively.

A. Acronyms

DR	Demand response
MCM	Market clearing model
MCP	Market clearing price
PSO	Power system operator
BVP	Balance vesting price
MILP	Mixed-integer linear programming
LP	Linear programming
EMA	Energy Market Authority
EMC	Energy Market Company
ACS	Additional consumer surplus
IP	Incentive payment
TNC	Total non-curtailable load

B. Constants

$VoLL$	Value of lost load ($5000/MWh).
D^n	Forecasted amount of system load or regulation (MW), $n = 1, 3$.
M	Number of supply offers.
T_i^n	Number of the price-quantity tranches of the i^{th} supply offer.
$P^n{}_{i,j}$	Price ($/MWh) of the j^{th} tranche of the i^{th} offer, $n = 1, 2, 3$.
$Q^n{}_{i,j}$	Quantity (MW) of the j^{th} tranche of the i^{th} offer, $n = 1, 2, 3$.
P_L	A high bidding price ($10 \times VoLL$).
K_s	Violation penalty factor for excess amount.
K_d	Violation penalty factor for deficit amount.
Q_E^1	Power to be exported (MW).
Q_I^1	Power to be imported (MW).
λ_0	Power loss factor.
λ_1	Risk adjustment factor for reserve.
λ_2	Reserve proportion factor.
O_i	Capacity (MW) of the generating unit associated with the i^{th} offer.
Inf	A large positive constant (MW).
$RegMAX_i$,	Maximum output (MW) associated with the i^{th} offer to dispatch regulation.
$RegMIN_i$	Minimum output (MW) associated with the i^{th} offer to dispatch regulation.
H	Number of load offers.
S_k	Number of the price-quantity tranches of the k^{th} load offer.
$LP_{k,j}$	Price ($/MWh) of the j^{th} tranche of the k^{th} load offer.
$LQ_{k,j}$	Quantity (MW) of the j^{th} tranche of the k^{th} load offer.
TL_k	Total load of the k^{th} load offer (MW).
TL_k^{pre}	Total load of the k^{th} load offer (MW) for the immediately preceding period.
RU_k, RD_k	Ramp-up and Ramp-down rate (MW/min) associated with the k^{th} load offer.
l_k^{pre}	Scheduled MW amount of the k^{th} load offer for the immediately preceding period.
ρ	Aggregate quantity (MWh) of the loads covered by regulatory contracts.

C. Variables

$q_{i,j}^n$	Scheduled amount (MW) of the j^{th} tranche of the i^{th} supply offer, $n = 1, 2, 3$
q_i^n	Scheduled amount (MW) of the i^{th} supply offer, $n = 1, 2, 3$.

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S. Zhou, Z. Shu and K. Tan are with Clean Technology Center, DNV GL, 16 Science Park Drive, 118227 Singapore (e-mails: {Shengfeng.zhou; zhen.shu; kelvin.tan}@dnvgl.com).

Y. Gao and H.B. Gooi are with School of Electrical and Electronic Engineering, Nanyang Technological University, 50 Nanyang Avenue, 63798 Singapore (e-mails: ygao007@e.ntu.edu.sg, ehbgooi@ntu.edu.sg).

S. Chen is with Accenture, #33-00 Raffles City Tower, 250 North Bridge Road, 179101 Singapore (e-mail: shuaixun.chen@accenture.com).

q^n	Total scheduled amount (MW) of energy, reserve and regulation, $n = 1, 2, 3$
q_s^n	Supply excess (MW), $n = 1,2,3$.
q_d^n	Supply deficit (MW), $n = 1,2,3$.
b_i^3	Binary integer variable for the i^{th} supply offer
$\alpha_i^n, \beta_i^3, w_k, u_k$	Slack variables (MW).
MCP^n	Market clearing price ($/MWh).
$l_{k,j}$	Scheduled amount (MW) of the j^{th} tranche of the k^{th} load offer.
l_k	Scheduled amount (MW) of the k^{th} load offer.
l	Total scheduled amount of load (MW).
TNC	Total non-curtailable load (MW).
INC_k	Individual non-curtailable load (MW) of the k^{th} load offer.
LC_k	Scheduled curtailment (MW) in the k^{th} load offer.
LCQ_k	Curtailed load (MWh) associated with the k^{th} load offer.
$LREF_k$	Reference power consumption (MW) of the k^{th}load offer for the current dispatch period.
$LREF_k^{pre}$	Reference power consumption (MW) of the k^{th} load offer for the immediately preceding period.
LCP	Load curtailment price ($/MWh)
IP_k	Incentive payment associated with the k^{th} load offer ($)

I. INTRODUCTION

THE wholesale electricity market of Singapore, as Asia's first liberalized electricity market, is constantly aiming to provide reliable and secure energy supply, and promote effective competition [1]. A recent important change in the market is the introduction of a demand response (DR) program which is scheduled for implementation in 2016. The newly introduced DR program is intended to reduce the wholesale electricity price when it is high by allowing the consumers to voluntarily reduce their energy demand. The final determination paper on this topic was issued in 2013 by the Energy Market Authority (EMA), the system operator of Singapore's electricity market [2]. In December 2015, the Energy Market Company (EMC), the independent market operator of Singapore's wholesale electricity market, publicized the modification of the market rules for implementation of the DR program [3]. This DR program is the first initiative in Singapore to allow consumers actively manage their demand in response to market prices.

Singapore's current wholesale market is a real-time market (spot market) consisting of a half-hourly auction of energy and ancillary services. During each auction period, generation companies provide energy and ancillary service offers which vary depending on the demand forecast and their willingness to enter the market for the upcoming dispatch period [1]. The trade of energy among the market participants, e.g. generation companies and load providers, is governed by a market clearing model (MCM). The MCM considers the offers from generators and clears the market by providing the market participants (1) the dispatch schedule which corresponds to the least total cost of energy supply, namely, the optimal dispatch schedule, and (2) the market clearing price (MCP), which is the price used to settle the transactions. When clearing the market, MCM has to balance the energy supply with the load forecast while satisfying the physical constraints from the generation facilities and transmission system, such as capacity, ramping rate and congestion. Moreover, the MCM has to fulfill a number of requirements, which are set by Power System Operator (PSO) for ensuring reliable and secure energy supply. The Singapore's MCM is different from many economic dispatch models discussed in the literature due to the fact that it schedules energy and ancillary services concurrently [4]-[7].

DR is well-known for bringing the energy market system-wide benefits including reducing energy prices, curbing exercise of market power, enhancing system securities and promoting efficient investments [5], [8]-[10]. A number of most common obstacles and challenges faced by DR, including those from consumer, producer and central market structure, are examined in [11]. In order to meet the DR goals and maximize the DR benefits, a variety of MCMs incorporating DR have been developed [8], [12]-[14]. In [8], a price-based self-scheduling model in the day-ahead market is formulated as a mixed integer linear programming (MILP) problem, in order to determine the optimal schedule of DR and maximize the aggregator's payoff. A decomposition algorithm is developed in [12] to address the optimization problem for market clearing with DR from end users. In [14], a real-time balancing market model is proposed to enable the elastic demand volumes and achieve system-wide balancing. In particular, the MCM of smart grid often features DR since it is considered as one of the key components in smart grid [15]-[18].

The Singapore's DR program is introduced to allow the consumers the option of managing their energy demand in response to the price signals through demand side bidding. Thus, during the occurrences of high energy prices, consumers can opt to curtail their energy consumption thereby leading to a reduction in the energy price. Conceptually, this has similar characteristics as some of the aforementioned DR works. Yet, the Singapore's DR program has two salient features that distinguish it from those discussed in the literature. The first feature is the form of its demand side offers and how the demand side offers are interpreted by the MCM. Unlike other demand side bidding offers, this DR program requires the load providers to bid on the energy curtailment rather than explicit energy consumption. The second feature is the incentive payment mechanism specially designed for promoting DR participation. With these two features, this DR program is an important step towards achieving a more liberalized electricity market in Singapore. The contribution of this paper is twofold. First, it provides an in-depth review of Singapore's wholesale electricity market while highlighting the key constraints which are imposed by Singapore's PSO. This review offers valuable references as Singapore's electricity market is well-known for its reliability. Second, it investigates the newly introduced DR program, which is Singapore's first initiative allowing consumers actively managing their loads, with an emphasis on the salient features which are designed to smoothly introduce DR into the current regulated market. Thus, this study serves as a valuable and instructive example for the market deregulation practice, and particularly to those markets intending to take the first initiative to introduce demand response.

In this work, the DR program is investigated through mathematical formulation of a MCM which incorporates the DR program. First, the current MCM which has no demand side bidding is introduced. A mathematical model is formulated to explain the current market clearing process, which is a co-optimization problem of simultaneously scheduling energy and ancillary services. Second, the demand side bidding of the DR program is introduced and a modified MCM with DR incorporated is developed. Third, the incentive payment mechanism which concerns how the DR participants are rewarded for their accepted bidden curtailments is elaborated. Extensive numerical analysis is performed to clearly demonstrate how the current MCM works and how the MCM with DR works.

The remainder of this paper is organized as follows. Section II presents an overview of the wholesale market and formulates the mathematical model of MCM. Section III discusses the details of the DR program and formulates a modified MCM with DR. Section IV reports the simulation analysis results. Section V draws conclusions of this work.

II. Formulation of current MCM

A. Overview of current market

In the wholesale market of Singapore, energy and ancillary services are simultaneously managed by the MCM. Among the various ancillary services, reserve and regulation are the two main types. Reserve refers to the generation capacity required to cover the energy loss when a generator or transmission line fails, and regulation refers to the generation capacity to cover the second-to-second variations between actual load and forecasted load. Before each half-hourly dispatch period, generation companies will have already decided their dispatchable generation units. Each of the dispatchable units will choose to bid on energy, reserve or regulation, or a combination of them, depending on not only its willingness, but also its eligibility for providing regulation and reserve. Without loss of generality, for simplicity this work assumes that all dispatchable units will bid on energy, reserve and regulation simultaneously with their respective offers. Each offer consists of a number of price-quantity tranches specifying the quantity of energy, reserve and regulation that the unit is willing to produce at the corresponding energy, reserve and regulation prices. Figure 1 shows a simplified energy offer. The reserve and regulation offers are of similar form. The capacity from the reserve offers is to cover the energy loss in case of unexpected outage, e.g., generator failure. Three types of reserve are required in Singapore to ensure a reliable energy supply. Among which, contingency reserve is the most critical. A reserve provision eligible unit is allowed to bid for and simultaneously provide all the three types of reserve. As contingency reserve is of the imperial role, for simplicity this work only considers this type of reserve.

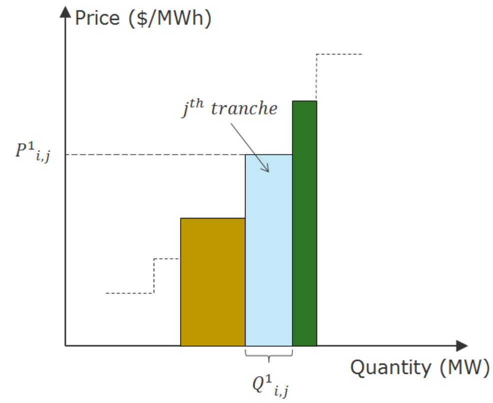

Figure 1 A supply offer with price-quantity tranches

Before submitting offers, the generation companies will be advised on the amount of the forecasted system load and the regulation requirement by the PSO. In contrast, the reserve requirement is calculated dynamically from the expected size of the contingency, which is associated with the specific dispatch schedule, rather than a fixed value given beforehand. Once the offers are submitted, the MCM will consider both the offers and the forecasted amount (of system load and regulation) to formulate a co-optimization problem to solve the optimal dispatch schedule and the associated MCP.

B. Dispatch Schedule

The MCM determines the accepted quantities, i.e., the MW amounts to be dispatched, of each price-quantity tranche of all offers. The scheduled capacity of one unit can be obtained through simply adding up the dispatched quantities of its tranches. Let q denote a vector whose elements are the accepted quantities of each price-quantity tranche of all offers. As such, q can be defined as

$$\boldsymbol{q} = [\boldsymbol{q_1^1}, \dots, \boldsymbol{q_M^1}, \boldsymbol{q_1^2}, \dots, \boldsymbol{q_M^2}, \boldsymbol{q_1^3}, \dots, \boldsymbol{q_M^3}]^T$$

where $\boldsymbol{q_i^1} = \left[q_{i,1}^1, \dots, q_{i,T_i^1}^1\right]$, $\boldsymbol{q_i^2} = \left[q_{i,1}^2, \dots, q_{i,T_i^2}^2\right]$ and $\boldsymbol{q_i^3} = \left[q_{i,1}^3, \dots, q_{i,T_i^3}^3\right]$ $(i = 1, \dots, M)$.

Let q_i^1, q_i^2 and q_i^3 denote the scheduled (accepted) energy, reserve and regulation of the i^{th} offer, respectively. Thus, the dispatch schedule is the set of q_i^1, q_i^2 and q_i^3 $(i = 1, \dots, M)$. Furthermore, let q^1, q^2 and q^3 denote the total scheduled energy, reserve and regulation, respectively. It is obvious that,

$$q_i^n = \sum_{j=1}^{T_i^n} q_{i,j}^n \ , \quad n = 1, 2, 3. \tag{1}$$

$$q^n = \sum_{i=1}^{M} q_i^n \ , \quad n = 1, 2, 3 \tag{2}$$

C. Constraints

Ideally, the energy, reserve and regulation to be dispatched should perfectly meet their respective requirements. However, this may lead to infeasibility, which is unacceptable in the real market. To address this issue, the scheduled amounts of energy, reserve and regulation are allowed to be different from their requirements by an excess amount or a deficit amount. To further enhance the robustness, the rest of constraints are relaxed as well by introducing slack variables. These slack variables are penalized in the objective function with large violation penalty factor forcing them to approach zero. The constraints that the MCM is subject to are discussed below.

1) Energy balance constraint

The sum of scheduled energy should match the demand forecast and the export/import plan. To ensure the feasibility, this constraint is relaxed to allow supply excess (i.e., q_s^1) and deficit (i.e., q_d^1). Furthermore, the power loss due to transmission is factored into the load side. Thus, the energy balance constraint can be expressed as

$$\begin{cases} q^1 + q_d^1 \geq (1+\lambda_0)D^1 + Q_E^1 - Q_I^1, \\ q^1 - q_s^1 \leq (1+\lambda_0)D^1 + Q_E^1 - Q_I^1. \end{cases} \tag{3}$$

It should be noted that Singapore's current MCM explicitly calculates the power loss on transmission lines. This work introduces λ_0 to simplify the power loss calculation.

2) Regulation balance constraint

Similar to the energy balance constraint, the regulation balance constraint can be expressed as:

$$\begin{cases} q^3 + q_d^3 \geq D^3, \\ q^3 - q_s^3 \leq D^3. \end{cases} \tag{4}$$

3) Contingency reserve balance constraint

Unlike the energy and regulation, the amount of reserve is given in a dynamic form, which is a function of the size of the largest generating unit and the power system response. The reserve capacity is required to be sufficient to cover the loss resulted from any generator, including both its scheduled energy quantity and reserve quantity. This capacity is further scaled by an adjustment factor λ_1 set by the PSO to ensure a more secure supply. The power system response, which is determined by the load damping and intertie contribution, is neglected in this work for the sake of simplicity. Consequently, this constraint can be expressed as

$$q^2 + q_d^2 \geq \lambda_1 \cdot \max_{i=1,..M}\{q_i^1 + q_i^2\}. \tag{5}$$

4) Generator capacity constraint

The total amount of energy, reserve and regulation to be produced by each dispatchable unit should not exceed its maximum generation capacity, i.e., O_i). This constraint can be written as

$$q_i^1 + q_i^2 + q_i^3 - \alpha_i^1 \leq O_i, \quad i = 1, \dots, M. \tag{6}$$

5) Constraint on supply of reserve

In order to prevent each unit from contributing too much reserve, the reserve from each dispatchable unit is only allowed up to a portion of its scheduled energy. This constraint can be written as

$$q_i^2 - \alpha_i^2 \leq \lambda_2 \cdot q_i^1, \quad i = 1, \dots, M, \tag{7}$$

where λ_2 is the ratio provided by PSO to limit the quantity of reserve which each generating unit can contribute.

6) Constraint on supply of regulation

When a unit is scheduled for dispatching regulation, it has to satisfy two constraints:

- The sum of its scheduled energy and its scheduled regulation is less than a pre-defined maximum amount (i.e., $RegMAX_{\mathrm{i}}$);
- Its scheduled energy is greater than its scheduled regulation by a pre-defined minimum amount (i.e., $RegMIN_i$).

Both $RegMAX_{\mathrm{i}}$ and $RegMIN_i$ are specific to the unit. Since these two constraints are valid only when a unit is scheduled for regulation, binary variables b_i^3 $(i = 1, \dots M)$are introduced with 1 indicating it is scheduled regulation and 0 indicating it is not scheduled for regulation. Thus, it is obtained that

$$\begin{cases} q_i^3 - Inf \cdot b_i^3 \leq 0, i = 1, \dots, M, \\ q_i^1 + q_i^3 - \alpha_i^3 - Inf \cdot (1 - b_i^3) \leq RegMAX_i, \\ q_i^1 - q_i^3 + \beta_i^3 + Inf \cdot (1 - b_i^3) \geq RegMIN_i. \end{cases} \tag{8}$$

7) Constraints on variables

The previously defined variables satisfy

$$\begin{cases} 0 \leq q_{i,j}^n \leq Q^n{}_{i,j}, \\ \alpha_i^n, \beta_i^3 \geq 0, \\ q_s^n, q_d^n \geq 0, \end{cases} \tag{9}$$
$$n = 1, 2, 3, \qquad i = 1, \dots, M, \qquad j = 1, \dots, T_i^n.$$

D. Objective Function

The objective of Singapore's MCM is to maximize the net benefit of the market, which is the sum of producer surplus and consumer surplus. To calculate the consumer surplus, the bidding price from demand side is required. Since currently there is no bidding from the demand side in the current market, the bidding price is set as a very large value (i.e., P_L). In addition to the net benefit, the penalties for the slack variables that are induced to relax the constraints are included in the objective function. Thus, the objective function is formulated as below:

$$f = P_L q^1 - g - v \tag{10}$$

where,

$$g = \sum_{n=1}^{3} \sum_{i=1}^{M} \sum_{j=1}^{T_i^k} P_{i,j}^n q_{i,j}^n \tag{11}$$

$$v = \sum_{n=1}^{3} (K_s q_s^n + K_d q_d^n) + \sum_{n=1}^{3} \sum_{i=1}^{M} K_s \alpha_i^n + \sum_{i=1}^{M} K_d \beta_i^3 \tag{12}$$

Note that P_L is a constant. Moreover, large violation penalty factors will push q^1 to meet the forecast value, i.e., D^1, which is also a constant. Thus, in the current MCM (which does not have demand side bidding), maximizing the net benefit is equivalent to minimizing the overall supply cost although these two forms of objective functions are fundamentally different. When demand side bidding is considered, the objective function will still be the net benefit whereas the specific form of the consumer surplus will be modified to incorporate the demand side bidding offers.

E. Current MCM and MCP

With above discussion, the MCM is formulated as,

$$\begin{gathered} Find\colon \boldsymbol{q}, \\ Maximizing\colon f \\ Subject\ to\colon (1) - (12). \end{gathered}$$

The market clearing price is the marginal cost price, which is defined as an incremental cost of producing an extra unit of generation. The MCP of energy, reserve and regulation are obtained along with solving the MCM since they are the dual variables or Lagrange multipliers corresponding to the balancing constraints (i.e., (3)-(5)), respectively.

III. FORMULATION OF MCM WITH DR

This section explains the demand side bidding of the new DR program and formulates a modified MCM with DR incorporated, with an emphasis on the market rule changes associated with the DR program.

A. Demand side bidding

1) Offer specification

In DR program, the bidding offers submitted by consumers consist of the following information:

- A series of price quantity tranches, which specify the quantity of energy that the consumer is willing to *curtail* at the corresponding prices. The price-quantity tranches in load offers are arranged with price in decreasing order (see Figure 2). It should be noted that the bidding prices are required to be greater than a price floor which is set at 1.5 times of the balance vesting price (BVP), which is (The BVP is a price designed to *"approximate the long run marginal cost of a new entrant that uses the most economic generating technology in operation in Singapore and contributes to more than 25% of total demand"* [1].) BVP is set by EMA quarterly. The intent of the price floor is to prevent the load providers from abusing the DR program, such as submitting at very low prices for load reductions that would have been carried out without DR. It is noted that the price floor is a relatively high price. As a result, the load curtailments will only occur when the energy prices are relatively high. In this respect, the DR program only provides the load providers limited flexibility in managing their loads in response to the price signals. However, it should be noted that the benefits of DR program is most significant during periods of high energy prices.
- The total load, which is a conservative estimation of the MW amount of demand if the load provider is not subject to any curtailment. The load provider will get penalized if it is consuming less energy than the total load implies. This total load is required to be greater than the sum of all the quantities indicated in the offer, i.e., $TL_k \geq \sum_{j=1}^{S^k} LQ_{k,j}$.

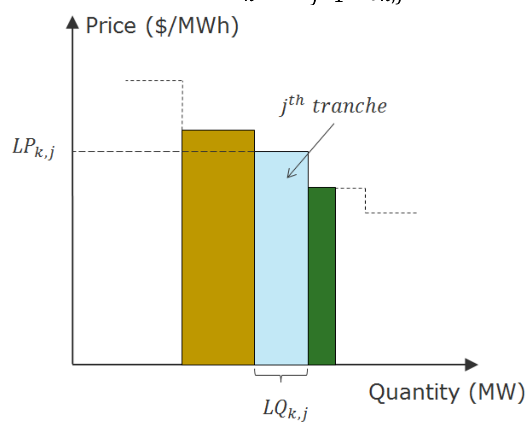

Figure 2 A load offer with price-quantity tranches.

- The load ramp-up rate and ramp-down rate, which specifies how fast the load reaches the instructed level. At the beginning of each dispatch period, the load provider is required to ramp up or down its energy withdrawal level at the respective ramp rates to reach the instructed level of energy and maintain such level to the end of the dispatch period. As a result, if provided the scheduled quantity for the immediately preceding period, the achievable load level for upcoming period can be calculated.

Table I gives an example of a demand side offer comprising two tranches. In this load offer, the consumer is willing to curtail 20 MW if the price is greater or equal to 400 $/MWh, and further curtail 30 MW if the price ramps up to 500 $/MWh.

TABLE I A LOAD OFFER EXAMPLE

Identity	Total load (MW)	Ramp-up rate (MW/min)	Ramp-down rate (MW/min)
NTU	100	2	2
Price #1 ($/MWh)	Quantity #1 (MW)	Price #2 ($/MWh)	Quantity #2 (MW)
500	30	400	20

2) Pre-processing of demand side bidding offer

To illustrate the pre-processing, *individual non-curtailable load* is first introduce. It refers to the forecasted amount of load that a load provider is going to consume when all of its bidden curtailments are accepted, i.e.,

$$INC_k = TL_k - \sum_{j=1}^{S_k} LQ_{k,j} \qquad (13)$$

The quantities in the price-quantity tranches are the amounts of load curtailment rather than the explicit amounts of load consumption. Thus, the individual non-curtailable load is used to transform the load offer (shown in Figure 2 and Table I) to a form which indicates the load quantities that load provider is willing to consume and the corresponding prices. In particular, the individual non-curtailable load is assigned a bidding price P_L, which is the same as how the load in the current MCM is treated. The transformed load offer is shown in Figure 3. It is observed that the only difference between the transformed load offer and the original load offer is the tranche of the individual non-curtailable load at the price P_L. Consequently, each of the transformed load offer can be split into two offers with the first consisting of only the individual non-curtailable load tranche and the second offer the same form as in Figure 2.

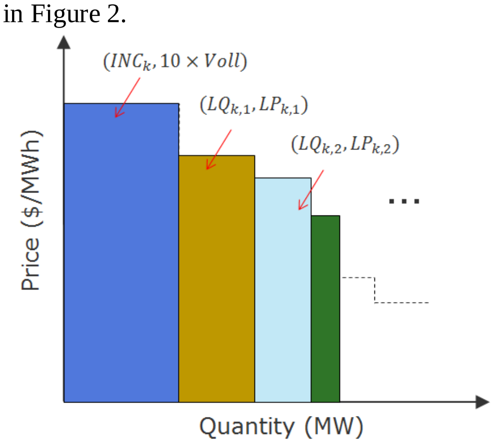

Figure 3 The transformed load offer

Since each TL_k in the load offer is specified by the load provider to give as a baseline for calculating its curtailment, the INC_k calculated from (13) may not accurately estimate the energy consumption of each load provider. Thus, the sum of all INC_k may not be able to accurately estimate the *total non-curtailable load (TNC)*, which is the total amount of forecasted system load that is not subject to any curtailment. To circumvent this issue, the total non-curtailable load is calculated using the forecasted system load (i.e., D^1) from PSO and the bidden quantities from load offers, i.e.,

$$TNC = D^1 - \sum_{k=1}^{H}\sum_{j=1}^{S_k} LQ_{k,j}\ . \tag{14}$$

The total non-curtailable load is non-negative. To illustrate this, (14) can be reformulated as

$$TNC = D^1 - \sum_{k=1}^{H} TL_k + \sum_{k=1}^{H}(TL_k - \sum_{j=1}^{S_k} LQ_{k,j})\ .$$

Since the total load is a conservative estimation, it is reasonable to conclude that the sum of all the total loads, i.e., $\sum_{k=1}^{H} TL_k$ is no greater than the forecast D^1. Furthermore, noting $TL_k \geq \sum_{j=1}^{S^k} LQ_{k,j}$, it can be deduced that $TNC \geq 0$.

With the introduction of TNC, all load offers are converted into two groups of tranches:

- The first group consists of all the price-quantity tranches from each load offer shown in Figure 2, i.e., $(LP_{k,j}, LQ_{k,j})$, $k = 1,..,H, j = 1,\dots,S^k$. All the parameters associated with this group are directly from the load offers.
- The second group only has one tranche with the price P_L and the quantity TNC , i.e., (P_L, TNC). This is an artificially created load offer to participate in the market clearing process.

B. Formulation of MCM with DR

This section presents the mathematical formulation of the new constraints, modification of constraints and modification of objective function, which are induced by the DR program.

1) Demand schedule

Similar to the supply dispatch schedule for generating units, the demand schedule refers to the set of instructions indicating which load providers are scheduled to and their scheduled capacities.

The demand schedule can be expressed as the set of the accepted quantities of each of the price-quantity tranches belonging to both groups as discussed in last section. Let l_0 denote the accepted quantity of the total non-curtailable tranche. The demand schedule can be written as $\boldsymbol{l} = [l_0, \boldsymbol{l_1}, \dots, \boldsymbol{l_H}]^T$ with $\boldsymbol{l_k} = [l_{k,1}, \dots, l_{k,S^k}]$ $(k = 1, \dots, H)$. Furthermore, l_k and l are introduced to denote the scheduled quantity of each load offer and the total scheduled load quantity, respectively, i.e.,

$$l_k = \sum_{j=1}^{S^k} l_{k,j}\ , k = 1, \dots, H, \tag{15}$$

$$l = l_0 + \sum_{k=1}^{H} l_k. \tag{16}$$

2) Constraints associated with DR

a) Modified energy balance constraint

With the demand side bidding, the demand is no longer a given forecasted value but a variable defined in (15). To handle this change, the energy balance constraint given in (3) is modified into the following form

$$\begin{cases} q^1 + q_d^1 \ \geq\ (1+\lambda_0)l + Q_E^1 - Q_I^1, \\ q^1 - q_s^1 \ \leq\ (1+\lambda_0)l + Q_E^1 - Q_I^1. \end{cases} \tag{17}$$

b) Load ramping constraint

Let $LQMAX_k$ and $LQMIN_k$ denote the upper bound and lower bound limiting the scheduled quantity l_k, respectively. It can obtain that

$$\begin{cases} LQMAX_k = INC_k^{pre} + l_k^{pre} - INC_k + RU_k \times 30 \\ LQMIN_k = \max\{INC_k^{pre} + l_k^{pre} - INC_k - RD_k \times 30, 0\} \end{cases} \tag{18}$$

Considering the upper and the lower bounds of the scheduled quantity of each load offer, the load ramping constraints is expressed as follows:

$$\begin{cases} l_k - w_k \leq LQMAX_k, \\ l_k + u_k \geq LQMIN_k, \end{cases} \tag{19}$$

c) Constraints on DR variables

The newly introduced variables associated with the DR satisfy the following constraints

$$\begin{cases} 0 \leq l_{k,j} \leq LQ_{k,j}, \\ 0 \leq l_0 \leq TNC, \quad k = 1, \dots, H, j = 1, \dots, S^k. \\ w_k, u_k \geq 0 \end{cases} \tag{20}$$

3) Modified objective function

Based on the pre-processing of load offers, the objective function in (10) is modified as follows to incorporate the load offers from the DR participants:

$$f^* = P_L l_0 + b - g - v - v' \tag{21}$$

where, g and v are defined in (11) and (12), respectively; b and v' are given by

$$b = \sum_{k=1}^{H}\sum_{j=1}^{S^k} LP_{k,j} l_{k,j} \tag{22}$$

$$v' = \sum_{k=1}^{H}(K_s w_k + K_d u_k). \tag{23}$$

4) MCM with DR and MCP

As can be seen from (21), the net benefit to be maximized depends on both the supply dispatch schedule and the demand schedule. The MCM with DR is summarized as

$$\begin{gathered} Find\text{:}\ \boldsymbol{q}, \boldsymbol{l} \\ Maximizing\text{:}\ \ f^* \\ Subject\ to\text{:}\ (1), (2), (4) - (22). \end{gathered}$$

Solving the above linear programming problem results in the optimal supply dispatch schedule and demand schedule, which collectively lead to the maximum net benefit. The overall process of the MCM with DR is summarized in Figure 4. Due to the change of energy balance constraint discussed in (17), the MCP for energy is now the Lagrange multiplier corresponding to (17) rather than (3). The MCPs of reserve and regulation correspond to (4) and (5), respectively.

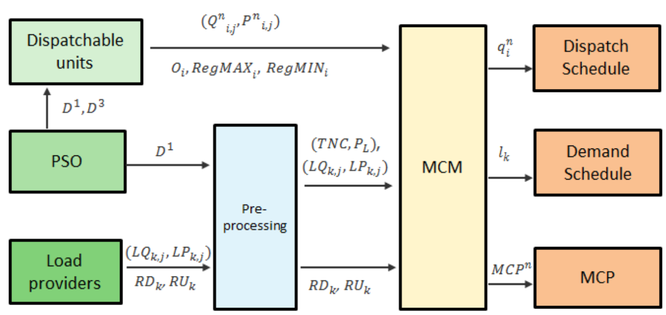

Figure 4 Overall process of the MCM with DR

IV. Incentive Payment

In order to promote DR participation, incentive payment is paid to the DR participants when their load curtailments are scheduled and the energy price is brought down.

For each load offer, its bidden curtailment may or may not be selected. Since the upper bound of the achievable load level (i.e., $LQMAX_k$) is considered in the MCM, the scheduled MW curtailment can be calculated as

$$LC_k = \min\left\{LQMAX_k, \sum_{j=1}^{S^k} LQ_{k,j}\right\} - l_k, k = 1, \dots H. \quad (24)$$

It is straightforward that LC_k is non-negative. Moreover, if $\sum_{k=1}^{H} LC_k > 0$, it is implied at least one load curtailment is accepted and thus incentive payment is initiated; if $\sum_{k=1}^{H} LC_k = 0$, it means there is no load curtailment scheduled and thus there is no need for incentive payment. As such, the former condition is used as the trigger to the calculation of load curtailment quantity and price. The rest of this section is discussed under the condition that $\sum_{k=1}^{H} LC_k > 0$.

The LC_k is the instructed MW curtailment rather than the actual MWh curtailed. However, the incentive payment is based on the actual MWh curtailment. The rest of this section explains the calculation of the MWh curtailment and the incentive payment price at \$/MWh for curtailed MWh amount.

A. Calculation of load curtailment quantity

Each load provider should have reached its instructed reference power consumption level before the end of the dispatch period. This reference level is given by

$$LREF_k = \min\{TL_k, INC_k + LQMAX_k\} - LC_k \quad (25)$$

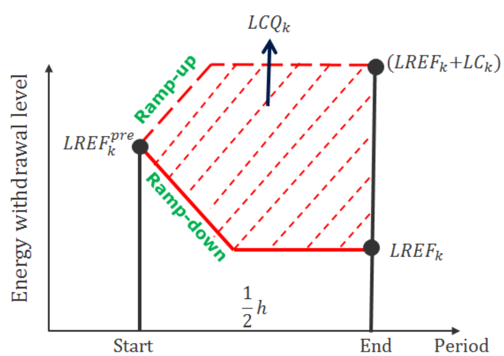

Figure 5 Calculation of curtailment quantity

The reference power consumption level of the immediately preceding dispatch period (i.e., $LREF_k^{pre}$) is considered as the load provider's power level at the beginning of the current dispatch period. As such, the power consumption level for both the beginning and the end of the current period are known. The load curtailment quantity in MWh, which is denoted as LCQ_k, is calculated as the difference between energy consumption without curtailment (i.e.,LBC_k) and with curtailment (i.e., LAC_k). LBC_k and LAC_k are the MWh energy consumptions within the dispatch period assuming that load is instructed to ramp up or down to reach $(LREF_k + LC_k)$ and $LREF_k$, respectively (see Figure 5). As such,

$$LCQ_k = LBQ_k - LAQ_k, k = 1, \dots, H \quad (26)$$

where

$$LBQ_k = \begin{cases} \frac{1}{2} \times (LREF_k + LC_k) + \frac{1}{2} \times \frac{(LREF_k + LC_k - LREF_k^{pre})^2}{RD_k \times 60} \\ \quad if\ LREF_k^{pre} \geq (LREF_k + LC_k), \\ \frac{1}{2} \times (LREF_k + LC_k) - \frac{1}{2} \times \frac{(LREF_k + LC_k - LREF_k^{pre})^2}{RU_k \times 60} \\ \quad if\ LREF_k^{pre} < (LREF_k + LC_k), \end{cases}$$

$$LAQ_k = \begin{cases} \frac{1}{2} \times LREF_k + \frac{1}{2} \times \frac{(LREF_k - LREF_k^{pre})^2}{RD_k \times 60} \\ \quad if\ LREF_k^{pre} \geq LREF_k, \\ \frac{1}{2} \times LREF_k - \frac{1}{2} \times \frac{(LREF_k - LREF_k^{pre})^2}{RU_k \times 60} \\ \quad if\ LREF_k^{pre} < LREF_k. \end{cases}$$

B. Calculation of load curtailment price

The DR participants are paid one third of the additional consumer surplus generated from the energy price reduction which results from the load curtailments dispatched. In order to calculate the price reduction, a reference energy price as if there is no DR program is required. This reference price is determined through a re-run of the MCM with the bidding prices of all load offers (i.e., $LP_{k,j}$) modified to P_L. Thus, for each dispatch period, the MCM with DR will be run twice, once with the original load offers and once with the modified load offers. The market clearing price for energy produced in the first case, denoted as MCP^1, will be used by the market participants, whereas the price generated in the second case, denoted as MCP^{ref}, serves as a reference only for calculation of the additional consumer surplus.

The additional consumer surplus is calculated as

$$ACS = \max\{(MCP^{ref} - MCP^1) \times (\tfrac{1}{2} \times D^1 - \rho), 0\} \quad (27)$$

where ρ, a known constant, is the aggregate quantity of those loads covered by regulatory contracts (e.g., vesting contracts).

The load curtailment price is calculated as

$$LCP = \frac{1}{3} \times \frac{ACS}{\sum_{k=1}^{H} LCQ_k} \quad (28)$$

With the load curtailment quantity in (25) and the load curtailment price in (27), the incentive payments to load providers can be calculated as

$$IP_k = LCQ_k \times LCP \quad (29)$$

V. Numerical Analysis

Numerical analysis is conducted to demonstrate how the current MCM and the modified MCM with DR work, and illustrate the incentive payment mechanism.

A. Current MCM

The details of the Singapore's market, e.g., the offer data from generation companies and the parameters of the generation facilities, are confidential. As such, it is not possible for this work to duplicate the MCM with real market data. Instead, this simulation focuses on illustrating the co-optimization process of the current MCM using a 10-unit representation. All of the 10 dispatchable units (i.e., $M = 10$) are bidding on energy, reserve and regulation. The details of their offers and other parameters are shown in Table II. It can be seen that each unit offers two quantity/price tranches for energy, reserve and regulation, respectively, i.e., $T_i^1 = T_i^2 = T_i^3 = 2$ $(i = 1, \dots, 10)$. The demand forecasts on system load and regulation are assumed to be 1150 MW and 90 MW, respectively. The other parameters are set as: $\lambda_0 = 2\%, \lambda_1 = 1.5$ and $\lambda_2 = 0.6$. With above setting, the dispatch schedule can be written as

$$\boldsymbol{q} = [q_{1,1}^1, q_{1,2}^1, \dots, q_{10,1}^1, q_{10,2}^1, q_{1,1}^2, q_{1,2}^2, \dots, q_{10,1}^2, q_{10,2}^2, q_{1,1}^3, q_{1,2}^3, \dots, q_{10,1}^3, q_{10,2}^3]^T.$$

TABLE II. SIMULATED OFFERS FROM TEN DISPATCHABLE UNITS

Offer	O_i (MW)	$RegMIN_i$ (MW)	$RegMAX_i$ (MW)	$Q^1{}_{i,1}$ (MW)	$Q^1{}_{i,2}$ (MW)	$P^1{}_{i,1}$ (\$/MWh)	$P^1{}_{i,2}$ (\$/MWh)	$Q^2{}_{i,1}$ (MW)	$Q^2{}_{i,2}$ (MW)	$P^2{}_{i,1}$ (\$/MWh)	$P^2{}_{i,2}$ (\$/MWh)	$Q^3{}_{i,1}$ (MW)	$Q^3{}_{i,2}$ (MW)	$P^3{}_{i,1}$ (\$/MWh)	$P^3{}_{i,2}$ (\$/MWh)
$i = 1$	600	100	550	150	350	-100	160	100	50	10	12	20	20	18.9	27
$i = 2$	400	100	350	250	150	0	150	100	60	15	16	15	15	15	29.9
$i = 3$	400	80	350	100	150	50	180	80	80	11	13.6	25	15	12	22
$i = 4$	400	100	350	150	200	60	170	80	80	21	29	10	10	23	30
$i = 5$	200	40	180	70	100	50	120	50	5	25	31	10	5	25	66
$i = 6$	200	40	180	60	80	80	125	80	10	27	30	10	10	17	43.9
$i = 7$	200	40	180	50	100	70	140	60	5	28.5	33	10	5	25	52
$i = 8$	100	10	90	50	50	50	190	30	10	19.7	32.9	10	10	11	28
$i = 9$	100	10	90	40	20	60	145	10	10	17	20	10	5	13	47
$i = 10$	50	5	45	20	20	80	150	5	5	22.9	35	5	5	16.9	73

The MCM simulation is performed in the MATLAB environment and the optimization problem is solved by intlinprog, which is a MILP solver for finding the minimum of a problem specified by:

$$\min_{v} Q^T v \text{ such that } \begin{cases} v(intcon) \text{ are integers} \\ A \cdot v \leq b, \\ Aeq \cdot v = beq, \\ lb \leq v \leq ub, \end{cases}$$

where, $Q, v, intcon, beq, lb,$ and ub are vectors; and A and Aeq are matrices [19].

The simulation results are shown in Tables III and IV (all the slack variables are found to be 0 and not shown in the result tables). The observations on the current MCM are summarized as below:

- From Table II, it is observed that the bidden prices for energy can be negative. As per the current market manual, the valid bidden price range for energy offer is $[-4500, 4500](\$/MWh)$. In practice, some generation facilities will always bid energy at the lowest allowable price to ensure that their generators are kept running since the cost of stopping the generators is high.
- From Table III, it is noted that MCM will fully dispatch the capacities with lower prices of each unit before dispatching those with higher prices from the same unit. The reason is that the capacities with lower prices have the priority to be dispatched compared to those with higher prices within one offer. However, it should be pointed out that the MCM may dispatch the capacities from some units with higher prices before the capacities are fully dispatched from those units with lower prices. This is because the co-optimization process has to take care of other constraints when different units are compared with respect to their offer prices.
- Another observation from Table IV is that the MCP can differ from the bidding prices. This is due to the fact that the MCPs are the marginal cost prices and are determined by the constraints (3)-(7) in the co-optimization process. It should be highlighted that the developed MCM is a MILP problem and the binaries render this optimization problem non-convex. Thus, no dual variables can be directly obtained from solving the MILP through intlinprog. However, once the MILP is solved, the optimal values for the binaries will be obtained. The MILP problem is converted into a LP problem through fixing the binaries at their optimal values and subsequently the MCPs can be obtained as the dual variables of the LP problem. One may refer to [20] for a critical review of obtaining MCP through the above described way.
- The developed MCM is a simplified model of Singapore's clearing process. It focuses on how Singapore's MCM uniquely sets the constraints for reserve and regulation whereas a few constraints, such as power loss of transmission lines, unit commitment, generator ramping rate, nodal prices, are not considered.

TABLE III. THE OPTIMAL DISPATCH SCHEDULE (MW)

Unit	$q^1_{i,1}$	$q^1_{i,2}$	$q^2_{i,1}$	$q^2_{i,2}$	$q^3_{i,1}$	$q^3_{i,2}$	q^1_i	q^2_i	q^3_i
$i = 1$	150	0	90	0	20	0	150	90	20
$i = 2$	250	0	0	0	15	0	250	0	15
$i = 3$	100	0	60	0	20	0	100	60	20
$i = 4$	150	0	80	0	0	0	150	80	0
$i = 5$	70	100	30	0	0	0	170	30	0
$i = 6$	60	80	50	0	10	0	140	50	10
$i = 7$	50	30	10	0	0	0	80	10	0
$i = 8$	50	0	30	0	10	0	50	30	10
$i = 9$	40	0	10	10	10	0	40	10	10
$i = 10$	20	0	5	0	5	0	20	5	5

TABLE IV. THE MARKET CLEARING PRICES (\$/MWH)

MCP^1 (energy)	MCP^2 (reserve)	MCP^3 (regulation)
140	28.50	23.73

B. MCM with DR

This section presents three numerical case studies for the modified MCM with DR incorporated. The supply offers and the forecasts on energy and regulation are assumed to be the same as those discussed in Section V.A. The demand side bidding offers are shown in Table V. All the prices in Table V are assumed to be higher than the floor price.

With the supply offers from Table II, the demand side offers in Table V, and the other necessary parameters shown in Table VI, the co-optimization problem described in (21) can be formulated and solved by intlinprog. The results are summarized in Tables VII and VIII. The calculation of LCP for Case 2 is presented here to illustrate the calculation process of the incentive payments. In Case 2, it can be obtained that $MCP^{ref} = \$140/MWh$ and $MCP^1 = \$124.10/MWh$. By using (27), it is obtained that $ACS = \$\ 4372.54$. Furthermore, considering the individual load curtailment which is shown in Table VII and (26), the load curtailment price can be obtained by using (28): $LCP = \$40.72/MWh$ (shown in Table IX).

The observations on the simulation of MCM with DR are summarized as below:

- From Table V, it can be seen that, unlike many DR where load providers indicate "willingness to consume", Singapore's demand side offers indicate "willingness to curtail" at different price points. Furthermore, the ramp rates are required to ensure that the scheduled curtailment (if any) is achievable and thus the DR is able to function as per designed.
- It can be seen from Table VII that no curtailment is dispatched in Case 1 and the market clearing prices (shown in Table VIII) are the same as those in Table IV. In Cases 2 and 3, there are different levels of curtailments and the energy prices drop accordingly. As the MCM with DR is a co-optimization seeking to minimize the overall cost of energy and ancillary service, allowing demand side bidding for energy consumption will affect the MCP for not only energy but also reserve and regulation. This can be observed from Table VIII through comparing Case 2 or 3 with Case 1.
- The ACS is considered as the benefits resulted from implementing the DR program. One third of the ACS is allocated as incentive payment to those load providers who contribute to the curtailment (shown in Table IX). Therefore, two thirds of the ACS is accrued to the rest of the load providers. Such an IP mechanism design is to ensure a fair return to all the DR participants. The incentive payments are recovered from all load providers through an uplift charge (load providers pay the energy at the price of MCP with an uplift charge).
- It should also be highlighted again that the load providers are only allowed to submit bids at prices higher than the floor price and hence the flexibility they have in managing their energy consumption is limited. As a result, no curtailment will be scheduled if the total load demand can be supplied at a price lower than the floor price. Furthermore, as the designed floor price (i.e., 1.5 times of BVP) is relatively high compared to the energy price, load curtailments will only be scheduled when the price spikes occur. In another word, no curtailment will be activated under normal conditions. To illustrate above point, the energy price statistics and BVP for the first half of 2016 are presented in Table X. It can be seen that (1) the energy price average for all the six months is much lower than the floor price, and (2) even the maximum energy price of March, April and June are lower than the floor price. This means that the energy price is lower than the floor price for most of the time (the energy prices during March, April and June are always lower than the floor price). It is also observed that the maximum price in some months can be very high (e.g, January and May), which means there were price spikes on some periods within those months. It is to bring down the energy prices during these periods with price spikes (a price higher than floor price can be considered as price spike) that Singapore's DR is designed. However, due to lack of real market data, it is not possible for this work to simulate the impacts of the new DR program on these price spikes. Hence, the real economic gain of the new DR program is not analyzed in this work. Nonetheless, from the results shown in Table VIII, the DR program will help to bring down the energy price once the energy price is higher than the bidden prices (which are higher than the price floor) from demand side.

TABLE V. SIMULATED OFFERS FROM DEMAND SIDE

Offer	*Load Provider*	TL_k (MW)	RU_k (MW/min)	RD_k (MW/min)	$LP_{k,1}$ (\$/MWh)	$LP_{k,2}$ (\$/MWh)	$LQ_{k,1}$ (MW)	$LQ_{k,2}$ (MW)
Case 1	*k=1*	450	10	10	170	155	40	30
	k=2	300	10	10	165	150	25	15
	k=3	400	10	10	150	143	35	30
Case 2	*k=1*	450	10	10	150	125	40	30
	k=2	300	10	10	130	120	25	15
	k=3	400	10	10	110	105	35	30
Case 3	*k=1*	450	10	10	120	110	40	30
	k=2	300	10	10	115	100	25	15
	k=3	400	10	10	105	100	35	30

TABLE VI. PARAMETERS ASSOCIATED WITH DEMAND SIDE OFFER

	Load Provider	INC_k^{pre} (MW)	l_k^{pre} (MW)	$LREF_k^{pre}$ (MW)	ρ (MWh)	TNC (MW)
Case 1, 2, 3	*k=1*	350	80	430	300	975
	k=2	250	70	320		
	k=3	300	100	400		

TABLE VII. THE OPTIMAL DEMAND SCHEDULE

	Load Provider	l_0 (MW)	$l_{k,1}$ (MW)	$l_{k,2}$ (MW)	LC_k (MW)	l (MW)
Case 1	*k=1*	975	40	30	0	1150
	k=2		25	15	0	
	k=3		35	30	0	
Case 2	*k=1*	975	40	30	0	1070
	k=2		25	0	15	
	k=3		0	0	65	
Case 3	*k=1*	975	0	0	70	975
	k=2		0	0	40	
	k=3		0	0	65	

TABLE. VIII THE MARKET CLEARING PRICES WITH DR (\$/MWH)

	MCP^1 (energy)	MCP^2 (reserve)	MCP^3 (regulation)
Case 1	140.00	28.50	23.73
Case 2	124.10	28.50	23.61
Case 3	120.00	28.50	23.60

TABLE. IX INCENTIVE PAYMENTS IN CASE 2

LCQ_1 (MWh)	LCQ_2 (MWh)	LCQ_3 (MWh)	ACS (\$)	Sum of IP (\$)	LCP (\$/MWh)
0	6.81	28.98	4372.5	1457.5	40.72

TABLE. X REAL ENERGY PRICE AND BVP IN SINGAPORE [21]

2016		Jan	Feb	Mar	Apr	May	June
Energy Price (\$/MWh)	Average	74.89	49.06	44.81	43.60	55.54	49.10
	Min.	28.08	0.00	22.10	24.47	35.42	36.20
	Max.	903.66	201.10	118.10	136.53	1010.75	76.47
BVP (\$/MWh)		119.48			100.01		

VI. Conclusions

This paper provides a comprehensive study of the market clearing process of Singapore's wholesale market and the DR program being introduced. Both the current MCM and how the new DR program is going to be incorporated into the current MCM are explained in detail and their mathematical models are formulated. The key requirements on reserve and regulation in the market clearing process are elaborated. The new constraints and requirements induced by the new DR program are also discussed.

The new DR program only allows the consumers limited flexibility in actively managing their loads in response to the price signals and therefore the benefits of DR may not be maximized. However, considering that this DR is first of its kind in Singapore, such a DR design ensures a smooth transition from the current regulated market to a deregulated market with demand side bidding and hence it is a reasonable compromise. As such, it provides a valuable reference for other electricity markets intending to achieve market deregulation through initiating DR programs.

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