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Standardized Contracts with Swing for the Market-Supported Procurement of Energy and Reserve: Illustrative Examples

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Contents

1 Introduction **2**

2 Proposed Standardized Contract System **6**
2.1 General Form of a Standardized Contract 6
2.2 Illustrative Example of a Standardized Contract 8
2.3 Support of SC Trading via Linked Forward Markets 11

3 RTM Illustrative Example **14**
3.1 Overview 14
3.2 Basic Assumptions 14
3.3 RTM Supply Offer Specifications 16
3.4 Power-Balance Constraints for ISOPorts 17
3.5 Expected Total Cost of a Power-Balanced ISOPort 19
3.6 Reserve Inherent in a Power-Balanced ISOPort 19
3.7 Practical Determination of Optimal ISOPorts 23
3.8 Incorporation of Transmission-Line Limits 25

4 Linkages between the RTM and the DAM **28**
4.1 Overview 28
4.2 DAM Linkages with Regulation Reserve Requirements 29
4.3 Contingency Reserve Considerations 33

5 Discussion **35**
5.1 Comparison with Real-World TSO/ISO Operations 35
5.2 Comparison with Existing Standardized Power Contracts 36
5.3 Discriminatory vs. Uniform Pricing of Contracts 37
5.4 Comparison with Existing VER Initiatives 38
5.5 Robust-Control Management of Uncertain Net Load 39
5.6 Amelioration of Merit-Order and Missing-Money Issues 40

6 Conclusion: Energy Policy Implications **41**

Abstract
Three key issues have arisen for centrally-managed wholesale electric power markets in Europe and the United States as they attempt to handle an increased penetration of variable energy resources. First, rigid definitions for energy and reserve products make it difficult to ensure appropriate compensation for important needed flexibility in start-up times, ramp-rates, power dispatch levels, and duration. Second, participation restrictions hinder the achievement of an even playing field for potential providers of flexible services. Third, reliance on out-of-market compensation for the provision of some valued services encourages strategic manipulation. This study examines the possibility of addressing these three issues through the introduction of standardized energy and reserve contracts with swing (flexibility) in their contractual terms. Concrete examples are used to demonstrate how the trading of these standardized contracts can be supported by linked forward markets in a manner that permits efficient real-time balancing of net load subject to system and reserve-requirement constraints. Comparisons with existing wholesale electric power markets are given, and key policy implications are highlighted.

Keywords: Electric power markets, variable energy resources, standardized contracts, swing (flexibility), energy and reserve co-optimization, linked forward markets

1 Introduction

European and U.S. electricity sectors have undergone substantial restructuring over the past twenty years. They have devolved from highly regulated systems operated by vertically integrated utilities to relatively decentralized systems based more fully on market valuation and allocation mechanisms.

As part of this restructuring, oversight agencies have been established at several different levels to encourage cooperation and coordination. The European Network of Transmission System Operators for Electricity (ENTSO-E), founded in 2008, currently consists of forty-one Transmission System Operators (TSOs) from thirty-four European countries; its primary task is to promote the coordinated management of the European power grid (ENTSO-E, 2015). The

U.S. Federal Energy Regulatory Commission (FERC) oversees the activities of six of the seven U.S. Independent System Operators (ISOs), established since the mid-1990s, that manage power system operations in electric energy regions comprising approximately 60% of U.S. generating capacity (EIA, 2015).[1]

These restructuring efforts have been driven by a desire to ensure efficient energy production and utilization, reliable energy supplies, affordable energy prices, and effective rules and regulations for environmental protection. In keeping with the latter goal, a dramatic change is taking place in energy mixes: namely, a rapid penetration of variable energy resources combined with a movement away from traditional thermal generation.

Variable energy resources (VERs) are renewable energy resources, such as wind and solar power, whose generation cannot be closely controlled to match changes in load or to meet other system requirements. Consequently, the integration of VERs tends to increase the volatility of net load (i.e., load minus as-available generation) as well as the frequency of strong ramp events. Flexibility in service provision by other types of resources then becomes increasingly important to maintain the reliability and efficiency of power system operations.

To accommodate increased VER penetration, TSOs and ISOs have introduced major changes in their market rules and operational procedures (Ela, 2011; ENTSO-E, 2014; Henry et al., 2014; NREL, 2012). These changes include new products to enhance net load following capability (e.g., ramping products), revised market eligibility requirements to encourage greater VER participation, and the introduction of capacity markets in an attempt to ensure sufficient thermal generation as a backstop for the intermittency of VER generation.

Nevertheless, several important issues arising from increased VER penetration still need to be resolved. One key issue is that energy and reserve products are variously defined and compensated across the different energy regions; see, e.g., Ellison et al. (2012). This makes it difficult to compare and evaluate the efficiency and fairness of system operations across these regions.

A second key issue is appropriate compensation for flexibility in service provision. TSO/ISO product definitions are specified in broad rigid terms (e.g., ca-

[1] One U.S. ISO, the Electric Reliability Council of Texas (ERCOT), is not under FERC jurisdiction because its grid has been deliberately designed to avoid interstate commerce transactions that would subject it to U.S. Federal jurisdiction (Spence and Bush, 2009).

pacity, energy, ramp-rate, regulation, non-spinning reserve) that do not permit resources to be further differentiated and compensated on the basis of additional valuable flexibility in service provision, such as an ability to ramp up and down between minimum and maximum values over very short time intervals.

A third key issue is that attempts to accommodate new products have led to the introduction of out-of-market (OOM) compensation processes. In 2011 FERC issued Order 755 to address OOM payment problems for one particular product category in U.S. ISO-managed wholesale power markets: namely, regulation with different abilities to follow electronic dispatch signals with high accuracy (FERC, 2011). However, given its limited scope, Order 755 does not fully eliminate the need in these markets to resort to OOM processes. As stressed by Bushnell (2013), the additional complexity resulting from OOM compensation processes provides increased opportunities for market participants to gain unfair profit advantages through strategic behaviors.

In response to these issues, a group of researchers sponsored by Sandia National Laboratories prepared a report (Tesfatsion et al., 2013) recommending that energy and reserve contracts be standardized in firm and option forms permitting separate pricing for service availability and for real-time service performance, and that the trading of these contracts be supported by a linked sequence of forward markets whose design is also standardized. This report builds on important earlier work by Bidwell (2005), Bunn (2004), Chao and Wilson (2002), and Oren (2005), who stress the relevance of options and two-part pricing for electricity markets.

The current study uses concrete numerical examples to explore the policy implications of the recommendations in Tesfatsion et al. (2013). In Section 2 we present a general template for a *Standardized Contract (SC)* with swing (flexibility) in its contractual terms, together with an illustrative SC example. We also outline in broad terms how the trading of SCs can be supported by linked centrally-managed day-ahead and real-time markets. In Section 3 and Section 4 we present our main results: namely, examples demonstrating how our proposed SC system, implemented via linked day-ahead and real-time markets, permits efficient real-time balancing of net load subject to system and reserve-requirement constraints.

Comparisons of our proposed SC system with existing European and U.S.

wholesale power market operations, standardized power contracts, pricing mechanisms, and VER initiatives are provided in Sections 5.1-5.4. In Section 5.5 we discuss how our SC system provides a robust-control approach to the handling of uncertain net load that avoids the need to specify detailed scenarios with associated probabilities, a common requirement of standard stochastic control approaches. In Section 5.6 we conjecture how our proposed SC system, extended to longer-term forward markets, could help to provide better incentives for thermal generation capacity investment as a backstop for the intermittency of VER generation by facilitating the resolution of merit-order and missing-money problems.

Throughout Sections 2-5 the following key policy implications of our proposed SC system are highlighted:

- permits full market-based compensation for availability and performance
- facilitates a level playing field for market participation
- facilitates co-optimization of energy and reserve markets
- supports forward-market trading of energy and reserve
- permits service providers to offer flexible service availability
- provides system operators with real-time flexibility in service usage
- facilitates accurate load forecasting and following of dispatch signals
- permits resources to internally manage UC and capacity constraints
- permits the robust-control management of uncertain net load
- eliminates the need for OOM payment adjustments
- reduces the complexity of market rules

The concluding Section 6 provides a concise summary discussion of each of these policy implications.

2 Proposed Standardized Contract System

2.1 General Form of a Standardized Contract

Energy refers to the actual generation of electrical energy, whereas reserve refers to generation-capacity availability. Four standardized contracts are proposed in Tesfatsion et al. (2013) to facilitate energy and reserve trading: namely, *firm contracts (FCs)* and *option contracts (OCs)* taking either fixed or swing form.

An FC is a non-contingent contract that requires specific performance from both counterparties. It obligates the holder to procure services from the issuer, and the issuer to deliver these services, under the contractually specified terms of the FC. In contrast, an OC gives the holder the right, but not the obligation, to procure services from the issuer under contractually specified terms. The right can be activated by exercise of the OC at a contractually permitted exercise time. Once exercised, an OC imposes specific performance obligations on both counterparties. That is, as for an FC, an exercised OC obligates the holder to procure services from the issuer, and the issuer to deliver these services, under the contractually specified terms of the OC.

An FC or OC is a *fixed* contract if each of its contractual terms is designated as a single possible value. An FC or OC is a *swing* contract if at least one of its contractual terms is designated as a set of possible values, thus permitting some degree of flexibility in its implementation. A fixed FC is a *block-energy* contract if its contractual terms obligate the issuer to maintain a specified constant power level during a specified time interval.

As depicted in Fig. 1, fixed/swing OCs, fixed/swing FCs, and block-energy contracts are all special cases of swing OCs. A swing OC reduces to a fixed OC if each of its contractual terms is a single possible value. A swing OC reduces to a swing FC if its permitted exercise times consist of a single time point that coincides with the contract procurement time. A swing FC reduces to a fixed FC if each of its contractual terms is a single possible value.

Hereafter, this study focuses on *Standardized Contracts (SCs)* in swing-OC form for the flexible provision of energy and reserve services. For concreteness, we next present a template for an SC that provides seven basic types of services for a particular operating hour: delivery location; down/up direction; ex-

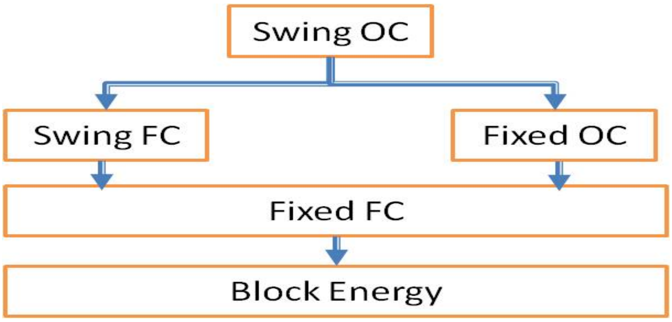

Figure 1: Hierarchical structure of contracts

ercise time; power-begin time; power-end time; down/up ramp rate; and power level. We illustrate swing in five of these service types by depicting their sets of possible values as intervals.[2]

Template for a Standardized Contract (SC):

$$\text{SC} \;=\; [k, d, T_{ex}, T_{pb}, T_{pe}, R_C, P_C, \phi] \tag{1}$$

$$\begin{aligned}
k &= \text{Location where service delivery is to occur}\\
d &= \text{Direction (down or up)}\\
T_{ex} = [t_{ex}^{min}, t_{ex}^{max}] &= \text{Range of possible exercise times } t_{ex}\\
T_{pb} = [t_{pb}^{min}, t_{pb}^{max}] &= \text{Range of possible power-begin times } t_{pb}\\
T_{pe} = [t_{pe}^{min}, t_{pe}^{max}] &= \text{Range of possible power-end times } t_{pe}\\
R_C = [-r^D, r^U] &= \text{Range of possible down/up ramp rates } r\\
P_C = [p^{min}, p^{max}] &= \text{Range of possible power levels } p\\
\phi &= \text{Performance payment method for real-time service performance}
\end{aligned}$$

The down/up limits $-r^D$ and r^U for the ramp-rates r (MW/min) are assumed to satisfy $-r^D \leq 0 \leq r^U$. The lower bound p^{min} for the power levels p (MW) is assumed to be non-negative. The direction (down or up) of an SC determines whether these power levels describe power curtailments or absorptions (down)

[2]SCs can take much more general forms than illustrated in the current study. For example, SCs can include other types of services such as voltage control, reactive power support, and energy storage capacity; swing can be present in any of these services; swing possible value sets do not need to be in interval form; and the operating period does not need to be an hour.

or power injections (up). The time points t_{ex}, t_{pb}, and t_{pe} denote specific calendar times expressed at the granularity of minutes.

The presence of swing in the contractual terms of an SC permits this SC to function as both an energy and a reserve product. Actual real-time service performance under such an SC cannot be determined until after the end of the operating hour H even if the SC is a firm (non-optional) contract. Consequently, the contractual terms of an SC include a performance payment method ϕ to be used to determine the ex-post payment to the SC issuer for real-time service performance (if any).

The performance payment method ϕ can take a wide variety of forms. For example, as illustrated in Section 3, ϕ might denote a pre-specified price ($/MWh) for delivered down/up energy. More generally, ϕ could denote a contingent price for delivered down/up energy that depends on market conditions (e.g., fuel prices) at the time of the delivery. Alternatively, ϕ could provide for the compensation of delivered power measured as *mileage*, i.e., as the sum of absolute-value up and down power movements over the real-time dispatch interval, a metric now being used for regulation service performance in many energy markets to meet the requirements of FERC Order 755 (Beacon Power, 2014).

In order for an SC to be implementable, its contractual terms must satisfy certain basic requirements. For example, t_{pb}^{min} cannot exceed t_{pe}^{max}. In this study it is presumed that an SC issuer is responsible for ensuring that it can feasibly implement the terms of any SC it offers. Realistically, however, penalties and eligibility requirements might need to be introduced to help ensure that the issuers of cleared SCs accurately follow real-time dispatch instructions, and that these instructions are in accordance with the contractual terms of the cleared SCs. These contract enforcement mechanisms could constitute part of the performance payment method ϕ included within each SC, or they could be instituted at the level of the power system as a whole.

2.2 Illustrative Example of a Standardized Contract

The illustrative up-energy SC depicted in Fig. 2 provides a combination of fixed and swing attributes. The delivery location (bus k) and direction (up) are specified as single values, as are the exercise time t_{ex}, the power-begin time t_{pb}, and the power-end time t_{pe}. On the other hand, the down/up ramp rate r and the power level p are swing attributes that can be varied over a range of values.

The darker (green) area within the resulting corridor of contractually-admissible power dispatch paths depicted in Fig. 2 is the up-energy injection that results from one such path. Any actual up-energy injection is compensated ex post in accordance with the performance payment method ϕ included among the SC's contractual terms. An example of a down-energy SC can be obtained from Fig. 2 by considering a 180° rotation of the depicted figure around the time axis.

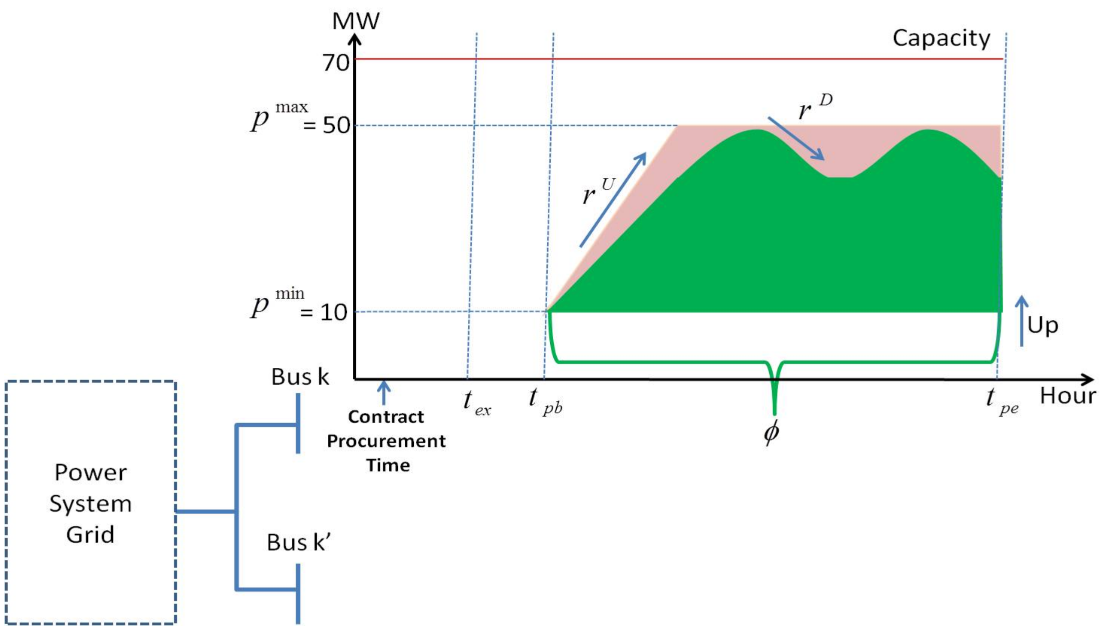

Figure 2: Example of an SC for up-energy with ramp-rate and power-level swing that is offered at bus k by a generator with a maximum capacity of 70MW

The SC depicted in Fig. 2 can be given a more concrete interpretation as an up-energy SC offered by a Demand Response Resource (DRR) into an ISO-managed day-ahead market (DAM) on day D-1 for a particular operating hour H on day D, as follows. Consider a Load Serving Entity (LSE) functioning as a load aggregator for a large distribution feeder connected to the transmission grid at a particular bus k. Residential households on this feeder have smart meters for their HVAC loads in wireless communication with the LSE that permits the LSE to make adjustments to these loads. The LSE has permission from each of these households to make small adjustments in their HVAC energy usage in return for an agreed-upon monthly lump-sum compensation. The LSE can participate in the DAM as a DRR either by offering up-energy implemented via HVAC load reductions or by offering down-energy implemented via HVAC load increases.

Suppose the LSE participates in the DAM on day D-1 as a DRR by offering the following up-energy SC at some offer price v for hour H of day D, where hour H is the time interval between 1300EST and 1400EST:

- Delivery location = Bus k
- Direction = Up
- T_{ex} = Exercise time t_{ex} = 0900EST on day D
- T_{pb} = Power-begin time t_{pb} = 1300EST on day D
- T_{pe} = Power-end time t_{pe} = 1400EST on day D
- R_C = [-1.3MW/min, $+1.4$MW/Min] = Range of possible down/up ramp rates r
- P_C = [10MW, 50MW] = Range of possible power levels p
- ϕ = Payment method for compensation of delivered power mileage, including a penalty payment adjustment for deviations between instructed and actual power mileage

Suppose, also, that this SC is cleared by the ISO. The ISO is then obligated to ensure that the DRR receives in compensation its offer price v as payment for making available for hour-H operations on day D the services included in this SC. In turn, the ISO has the right, but not the obligation, to exercise this SC at 0900EST on day D.

If the SC is exercised, the DRR must be ready to follow any electronic dispatch signal on day D, starting at time t_{pb} = 1300EST and ending at time t_{pe} = 1400EST, that calls for the DRR to provide a path of power injections lying within its offered range P_C of power levels that can feasibly be achieved without violating the DRR's offered range R_C of down/up ramp rates. In turn, the ISO is obligated to ensure that the DRR is compensated ex post for the mileage of this controlled power path in accordance with the terms of the performance payment method ϕ.

2.3 Support of SC Trading via Linked Forward Markets

As in Tesfatsion et al. (2013), we propose that SC trading be supported by a sequence of linked centrally-managed forward markets whose planning horizons can range from minutes to years. For concreteness, however, we focus in this study on the support of SC trading by means of linked day-ahead and real-time markets that are centrally managed by a non-profit *Independent System Operator (ISO)*; see Fig. 3.

Market Type	Participants	Contracts	Decision Variables	ISO Optimization Method
Day-Ahead Market (DAM)	LSEs	SC Block-Energy Bids	LSE SC Bids; Disp. GenCo / DRR / ESD SC Offers; ISO SC Bids	Security-Constrained Unit Commitment (SCUC) & Security-Constrained Economic Dispatch (SCED)
	Disp. GenCos, DRRs, and ESDs	SC Offers		
	Non-Disp. VERs	—		
	ISO	SC Bids		
Real-Time Market (RTM)	Disp. GenCos, DRRs, and ESDs	SC Offers	Disp. GenCo / DRR / ESD SC Offers; ISO SC Bids	SCED
	Non-Disp. VERs	—		
	ISO	SC Bids		

Figure 3: Proposed ISO-managed day-ahead and real-time markets

The non-ISO participants in our proposed day-ahead market (DAM) and real-time market (RTM) include: (i) *Load-Serving Entities (LSEs)* who submit SC demand bids in the form of block energy contracts on behalf of retail energy customers; (ii) dispatchable *Generation Companies (GenCos)*, *Demand Response Resources (DRRs)*, and *Energy Storage Devices (ESDs)* who submit SC supply offers; and (iii) non-dispatchable VERs whose as-available generation is treated as negative load.[3] The requirement that LSE SC demand bids be in block-energy form avoids the need for LSEs to exercise load-balancing discretion in the implementation of SCs with swing or option exercise times.

Participation in our proposed DAM/RTM processes is not meant to preclude electricity traders from procuring physical and financial instruments in power exchanges and over-the-counter power markets to hedge their price and volume risks. However, physical instruments whose terms require the use of transmission line facilities must be self-scheduled and cleared in the DAM or RTM to ensure transmission availability and overall system reliability.

The ISO managing the DAM undertakes *Security-Constrained Unit Commitment (SCUC)* and *Security-Constrained Economic Dispatch (SCED)* conditional on LSE SC demand bids, ISO SC demand bids (for reserve procurement only), and SC supply offers from dispatchable GenCos, DRRs, and ESDs. To retain the ISO's non-profit status, all costs incurred by the ISO for SC procurement must be passed through to market participants.

This cost pass-through could simply require all procurement costs to be allocated to the LSEs in proportion to their share of real-time loads. However, the presence of performance payment methods ϕ in SC bids/offers permits more sophisticated arrangements. For example, an LSE's cost allocation could be based in part on its forecasting performance, measured ex post by comparing its cleared SC demand bids against the actual real-time loads of its customers; and an SC supplier's cost allocation could be based in part on the accuracy of its service performance, measured ex-post by examining how well it was able to follow real-time dispatch instructions.

The ISO's DAM SCUC/SCED objective is to minimize the expected total net cost of ensuring that sufficient generation is available to balance next-day forecasted net loads with suitable local and system-wide reserve buffers. Dispatchable generation availability is determined from dispatchable GenCo, DRR, and/or ESD supply offers. Next-day net load forecasts for power-balance pur-

[3] As discussed in Section 5.4, our proposed SC system could be generalized to allow designated types of VERs to offer their generation as "dispatchable intermittent resources" in DAM/RTM operations, as is now being permitted in MISO (2011). However, this would raise a number of issues best left for future studies, e.g., should VERs be charged or penalized the same as ordinary dispatchable generation for deviations from their cleared dispatch offers?

poses are determined from LSE SC demand bids and forecasted VER generation. Reserve buffers are ensured by ISO SC demand bids.

As usual, the DAM SCUC/SCED is subject to unit commitment (UC) conditions, generation-capacity limits, power-balance constraints, transmission-line limits, and both local and system-wide reserve-requirement constraints. However, the imposition of the UC conditions and generation-capacity limits occurs through the contractual terms of the DAM SC supply offers rather than through ISO-imposed constraints.

We also propose an ISO-managed RTM that runs a SCED every five minutes. Dispatchable GenCos, DRRs, and ESDs can offer SCs into the RTM. Only the ISO is permitted to procure these SCs, for balancing and reserve procurement purposes; and all ISO RTM procurement costs must be passed through to market participants in order to preserve the non-profit status of the ISO.

The ISO's RTM SCED objective is to minimize the expected total cost of ensuring that adequate generation is available to balance ISO-forecasted real-time net loads with suitable local and system-wide reserve buffers, given the existing inventory of previously-cleared SCs. This RTM SCED is subject to generation-capacity limits, power-balance constraints, transmission-line limits, and both local and system-wide reserve-requirement constraints. The imposition of the generation-capacity limits occurs through the contractual terms of the RTM SC supply offers rather than through ISO-imposed constraints.

SCs can provide a wide diversity of services through their contractual terms. As discussed in greater detail in Section 5.3, appropriate compensation for these diverse services requires a flexible pricing mechanism. Our DAM and RTM are therefore formulated as discriminatory-price auctions in which participants pay (or are paid) their bid/offer prices for cleared SCs. These bid/offer price payments are compensations for service availability. Any real-time service performance rendered through these cleared SCs is compensated ex post in accordance with the performance payment methods appearing among the contractual terms of the cleared SCs.

Finally, SCs with swing in their contractual terms can function as both energy and reserve, and SCs in option form can also function as reserve even if their contractual terms are fixed. Consequently, our proposed DAM and RTM intrinsically involve a co-optimization of energy and reserve.

The next two sections use concrete examples to demonstrate how SC trading can be supported by means of our proposed linked DAM and RTM processes in a way that ensures optimal balancing of real-time net loads subject to system and reserve-requirement constraints.

3 RTM Illustrative Example

3.1 Overview

Sections 3.2 through 3.7 present a numerical example illustrating how SC trading can be supported by means of an RTM in the absence of transmission congestion and without consideration of linkages to earlier DAM processes. The handling of RTM transmission congestion is addressed in Section 3.8, and linkages with earlier DAM processes are considered in Section 4.

3.2 Basic Assumptions

Suppose an RTM takes place immediately prior to a particular operating period for which no congestion is anticipated. For concreteness, we assume this operating period is a particular hour H on a particular day D, expressed at the granularity of minutes.

Net load for hour H consists of aggregate load minus aggregate VER as-available generation. The net load profile for hour H that the ISO forecasts at the start of the RTM takes the form given in Fig. 4. The objective of the ISO managing the RTM is to ensure that this forecasted net load profile is balanced by generation with an appropriate reserve buffer, keeping costs to a minimum. The ISO attempts to achieve this objective by procuring a suitable combination of SCs from dispatchable generation suppliers participating in the RTM.

These dispatchable suppliers are assumed to consist of three GenCos with the following ramp-rate and generation-capacity attributes, expressed in Section 2.1 notation:

$$\text{G1}: \; r_1^D = r_1^U = 120\text{MW/min}, \text{Cap}_1^{min} = 0\text{MW}, \; \text{Cap}_1^{max} = 600\text{MW}$$
$$\text{G2}: \; r_2^D = r_2^U = 200\text{MW/min}, \text{Cap}_2^{min} = 0\text{MW}, \; \text{Cap}_2^{max} = 700\text{MW}$$

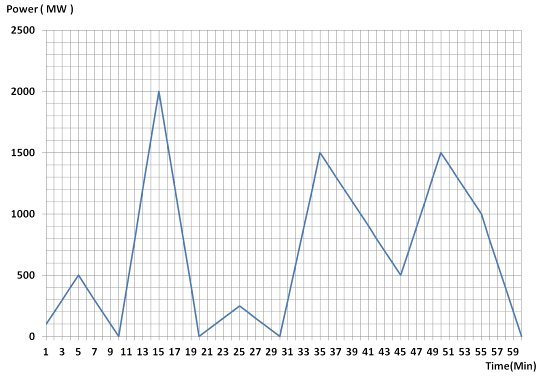

Figure 4: ISO-forecasted net load profile for hour H of day D at start of RTM

$$\text{G3}: \; r_3^D = r_3^U = 300\text{MW/min}, \text{Cap}_3^{min} = 0\text{MW}, \; \text{Cap}_3^{max} = 900\text{MW}$$

Each of these GenCo offers into the RTM a collection of portfolios, called *GenPorts*, together with associated GenPort offer prices. A GenPort consists of one or more SCs whose terms the GenCo could simultaneously fulfill during hour H if called upon to do so by the ISO. The ISO can clear at most one GenPort from each GenCo in the RTM.

The offer price $\text{v}_{i,j}$ for $\text{GenPort}_{i,j}$ is the payment requested by Gi for guaranteeing it will be available in hour H to fulfill the terms of the SCs included in $\text{GenPort}_{i,j}$ if signalled to do so. Thus, $\text{v}_{i,j}$ compensates Gi for service availability costs, such as avoidable fixed costs and lost opportunity costs. In addition, assuming $\text{GenPort}_{i,j}$ is cleared by the ISO, Gi will also receive ex post performance payments for any services it renders during hour H under the contractual terms of the SCs in $\text{GenPort}_{i,j}$. Any such performance payments will be determined in accordance with the performance payment methods ϕ included among the contractual terms of the SCs in $\text{GenPort}_{i,j}$. For the example at hand, each of these performance payment methods ϕ is assumed to take the form of a pre-specified price ($/MWh) for delivered down/up energy.[4]

As clarified in subsequent sections, this two-part pricing scheme permits the GenCos to ensure the recovery of their expected total costs through a market process, taking into account their local attributes and conditions. It also permits

[4]For example, each $\text{SC}_{i,j,m}$ in $\text{GenPort}_{i,j}$ could correspond to a distinct generation unit m owned by Gi, and the performance payment method $\phi_{i,j,m}$ for $\text{SC}_{i,j,m}$ could be a down/up energy price ($/MWh) given by the expected next-day marginal dispatch cost for unit m.

the ISO to closely tailor the cleared RTM GenPorts to real-time needs for net load balancing subject to system and reserve-requirement constraints.

The ISO is permitted to clear at most one GenPort from each GenCo in the RTM. The resulting cleared GenPorts can thus be represented in the following *ISO Portfolio (ISOPort)* form:

$$\text{ISOPort} = \{\text{GenPort}_1, \text{GenPort}_2, \text{GenPort}_3\}\,, \tag{2}$$

where no procurement from a GenCo Gi (GenPort$_i$=None) is possible.

3.3 RTM Supply Offer Specifications

A GenCo's RTM supply offer is a collection of GenPorts together with associated GenPort offer prices. Suppose each GenCo offers up-energy in firm contract form, i.e., exercise time t_{ex} = $t_{ex}^{min} = t_{ex}^{max}$ = RTM end-time. Suppressing location (k), direction (up), the exercise time t_{ex}, and measurement units from SC representations for ease of exposition, the RTM supply offers of GenCos G1, G2, and G3 are assumed to take the following form:

G1's supply offer consists of two GenPorts, each with one SC:

$$\text{GenPort}_{1,1} = \{\text{SC}_{1,1}\} \text{ at offer price } \text{v}_{1,1}, \tag{3}$$
$$\text{SC}_{1,1} = [t_{pb} = 0,\ t_{pe} = 60,\ |r| \leq 100,\ 0 \leq p \leq 500,\ \phi = 100]$$
$$\text{GenPort}_{1,2} = \{\text{SC}_{1,2}\} \text{ at offer price } \text{v}_{1,2}, \tag{4}$$
$$\text{SC}_{1,2} = [t_{pb} = 0,\ t_{pe} = 60,\ |r| \leq 120,\ 0 \leq p \leq 500,\ \phi = 105].$$

G2's supply offer consists of three GenPorts with multiple SCs:

$$\text{GenPort}_{2,1} = \{\text{SC}_{2,1,1}, \text{SC}_{2,1,2}\} \text{ at offer price } \text{v}_{2,1}, \tag{5}$$
$$\text{SC}_{2,1,1} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 200,\ 0 \leq p \leq 600,\ \phi = 135]$$
$$\text{SC}_{2,1,2} = [t_{pb} = 30,\ t_{pe} = 60,\ |r| \leq 200,\ 0 \leq p \leq 600,\ \phi = 130]$$
$$\text{GenPort}_{2,2} = \{\text{SC}_{2,2,1}, \text{SC}_{2,2,2}, \text{SC}_{2,2,3}\} \text{ at offer price } \text{v}_{2,2}, \tag{6}$$
$$\text{SC}_{2,2,1} = [t_{pb} = 0,\ \ t_{pe} = 10,\ |r| \leq 100,\ 0 \leq p \leq 100, \phi = 105]$$
$$\text{SC}_{2,2,2} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 200,\ 0 \leq p \leq 600, \phi = 135]$$
$$\text{SC}_{2,2,3} = [t_{pb} = 30,\ t_{pe} = 60,\ |r| \leq 200,\ 0 \leq p \leq 600, \phi = 130]$$

$$\text{GenPort}_{2,3} = \{\text{SC}_{2,3,1}, \text{SC}_{2,3,2}, \text{SC}_{2,3,3}\} \text{ at offer price } \text{v}_{2,3}, \tag{7}$$
$$\text{SC}_{2,3,1} = [t_{pb} = 0,\ t_{pe} = 10,\ |r| \leq 100,\ 0 \leq p \leq 100,\ \phi = 105]$$
$$\text{SC}_{2,3,2} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 200,\ 0 \leq p \leq 700,\ \phi = 140]$$
$$\text{SC}_{2,3,3} = [t_{pb} = 30,\ t_{pe} = 60,\ |r| \leq 200,\ 0 \leq p \leq 700,\ \phi = 135]$$

G3's supply offer consists of two GenPorts with multiple SCs:

$$\text{GenPort}_{3,1} = \{\text{SC}_{3,1,1}, \text{SC}_{3,1,2}, \text{SC}_{3,1,3}\} \text{ at offer price } \text{v}_{3,1}, \tag{8}$$
$$\text{SC}_{3,1,1} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 300,\ 0 \leq p \leq 900,\ \phi = 175]$$
$$\text{SC}_{3,1,2} = [t_{pb} = 33,\ t_{pe} = 39,\ |r| \leq 200,\ 0 \leq p \leq 400,\ \phi = 155]$$
$$\text{SC}_{3,1,3} = [t_{pb} = 48,\ t_{pe} = 54,\ |r| \leq 200,\ 0 \leq p \leq 400,\ \phi = 155]$$
$$\text{GenPort}_{3,2} = \{\text{SC}_{3,2,1}, \text{SC}_{3,2,2}, \text{SC}_{3,2,3}\} \text{ at offer price } \text{v}_{3,2}, \tag{9}$$
$$\text{SC}_{3,2,1} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 300,\ 0 \leq p \leq 900,\ \phi = 175]$$
$$\text{SC}_{3,2,2} = [t_{pb} = 30,\ t_{pe} = 39,\ |r| \leq 200,\ 0 \leq p \leq 400,\ \phi = 150]$$
$$\text{SC}_{3,2,3} = [t_{pb} = 44,\ t_{pe} = 54,\ |r| \leq 200,\ 0 \leq p \leq 400,\ \phi = 150]$$

3.4 Power-Balance Constraints for ISOPorts

Any ISOPort cleared by the ISO in the RTM must permit the achievement of a *Zero Balance Gap (ZBG)*, i.e., an exact balancing of RTM-cleared generation against the ISO's forecasted hour-H net load profile in Fig. 4. For example, Figs. 5-7 show how each of the following ISOPorts enables the achievement of a ZBG:

$$\text{ISOPort}_1 = \{\text{GenPort}_{1,1}, \text{GenPort}_{2,2}, \text{GenPort}_{3,1}\} \tag{10}$$
$$\text{ISOPort}_2 = \{\text{GenPort}_{1,1}, \text{GenPort}_{2,3}, \text{GenPort}_{3,1}\} \tag{11}$$
$$\text{ISOPort}_3 = \{\text{GenPort}_{1,2}, \text{GenPort}_{2,3}, \text{GenPort}_{3,2}\} \tag{12}$$

Each color in these figures indicates the dispatch of generation from a particular GenPort for a particular GenCo, and different shades of the same color indicate the dispatch of generation from distinct SCs within a particular GenPort.

Consider, in particular, Fig. 6 for ISOPort_2 in (11). The yellow areas correspond to $\text{GenPort}_{1,1}$ in (3), and the single shade of yellow represents energy

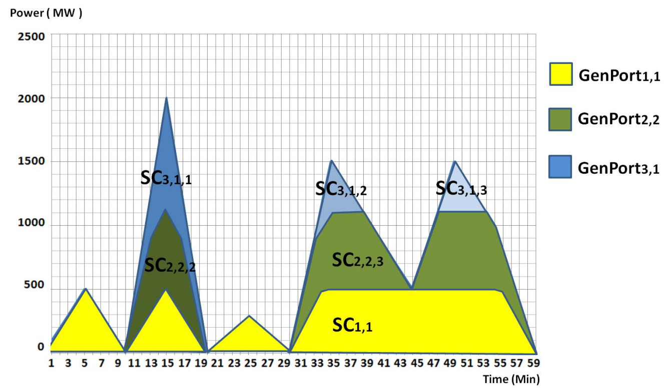

Figure 5: Zero balance gap achieved by ISOPort$_1$ for hour H of day D

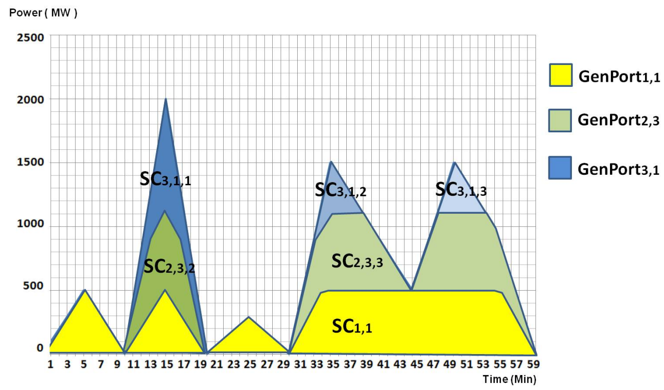

Figure 6: Zero balance gap achieved by ISOPort$_2$ for hour H of day D

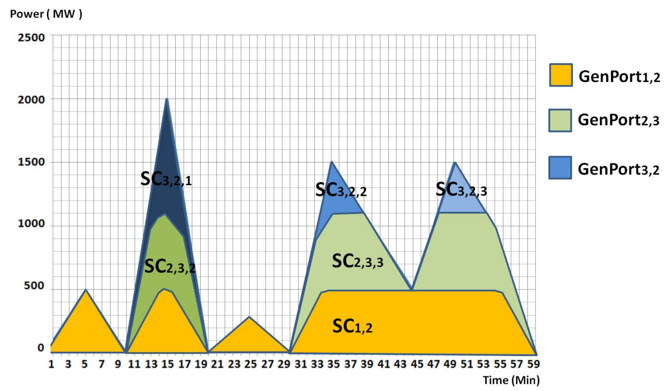

Figure 7: Zero balance gap achieved by ISOPort$_3$ for hour H of day D

dispatched via this GenPort's single SC constituent, $\mathrm{SC}_{1,1}$. The green areas correspond to $\mathrm{GenPort}_{2,3}$ in (7), and the two areas with different shades of green represent the energy dispatched via two of this GenPort's three SC constituents, $\mathrm{SC}_{2,3,2}$ and $\mathrm{SC}_{2,3,3}$. Finally, the blue areas correspond to $\mathrm{GenPort}_{3,1}$ in (8), and the three areas with different shades of blue represent the energy dispatched via this GenPort's three SC constituents, $\mathrm{SC}_{3,1,1}$, $\mathrm{SC}_{3,1,2}$, and $\mathrm{SC}_{3,1,3}$.

3.5 Expected Total Cost of a Power-Balanced ISOPort

Consider any ISOPort=($\mathrm{GenPort}_1$,$\mathrm{GenPort}_2$,$\mathrm{GenPort}_3$) that achieves a ZBG for hour H. The expected total cost of this ISOPort is the sum of payments arising from two sources: (i) the portfolio offer prices $\{v_1, v_2, v_3\}$ that must be paid to GenCos G1, G2, and G3 for the procurement of $\mathrm{GenPort}_1$, $\mathrm{GenPort}_2$, and $\mathrm{GenPort}_3$; and (ii) the total performance payments the ISO expects it will have to make to G1, G2, and G3 for down/up energy delivery during hour H under the contractual terms of these constituent GenPorts in order to achieve the ZBG.

For example, to calculate the expected total performance payments (ii) implied by the ZBG-implementation of $\mathrm{ISOPort}_2$ depicted in Fig. 6, first measure the energy (MWh) for each of the areas in Fig. 6 with a distinct color shading; each such area corresponds to a distinct SC implementation. Next, multiply each of these energy amounts by the performance price ϕ (\$/MWh) included among the contractual terms of the corresponding SC. Finally, add up all of these amounts.

3.6 Reserve Inherent in a Power-Balanced ISOPort

The achievement of a ZBG by an ISOPort implies that the generation available through this ISOPort is capable of balancing the ISO's *forecasted* hour-H net load profile. However, if the SCs constituting this ISOPort include swing, then the ISOPort can also achieve a ZBG for a range of hour-H net load profiles that deviate from the ISO's forecasted hour-H net load profile. Hereafter, this range will be referred to as the *Reserve Range (RR)* of the ZBG ISOPort.

The RR of a ZBG ISOPort with swing in its contractual terms is a robust-control device for net load balancing, eliminating the need for the ISO to consider detailed net load scenarios and scenario probabilities. However, its exact form depends in a complicated manner on the particular attribute specifications of the SCs that constitute the ISOPort as well as on the minute-by-minute operating state of the *GenCo suppliers*, i.e., the GenCos that have offered these SCs. Consequently, in any practical application, the RR will have to be approximated.

For example, Figs. 8 through 10 plot approximate RRs for ISOPorts 1, 2, and 3 in (10) through (12) by assuming that the GenCo suppliers at the start of each minute M are at their ZBG-generation levels. The depicted approximate RRs are conditional on the ISO's forecasted hour-H net load profile shown in Fig. 4 and on the ISO's hour-H ZBG implementations for ISOPorts 1, 2, and 3 shown in Figs. 5 through 7.

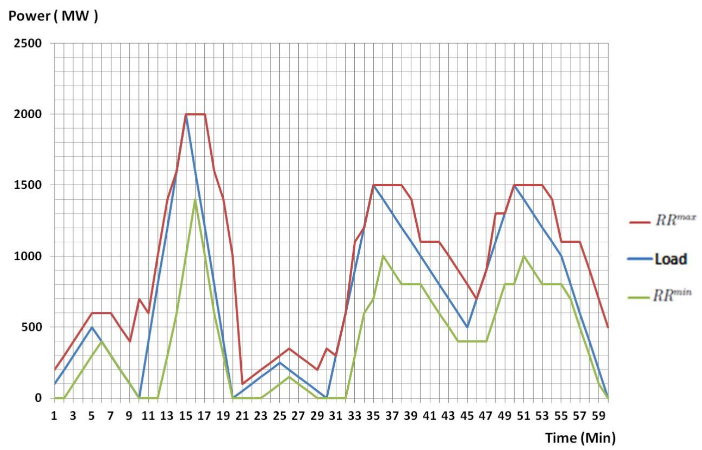

Figure 8: Reserve range RR for ISOPort$_1$ during hour H of day D

In particular, the approximate RR depicted in Fig. 9 for ISOPort$_2$ was derived by means of the following steps, applicable for any ZBG ISOPort. At the start of each minute M of hour H, calculate the minimum and maximum power levels RR_M^{min} and RR_M^{max} that could be attained at the end of minute M. These minimum and maximum power levels depend on: (a) the contractual terms of the SCs constituting ISOPort$_2$; (b) the particular ZBG implementation of ISOPort$_2$ for hour H; and (c) the ZBG operating state of each GenCo supplier for ISOPort$_2$ at the start of each minute M of hour H.

Specifically, for each GenCo supplier Gi, and for each minute M during the

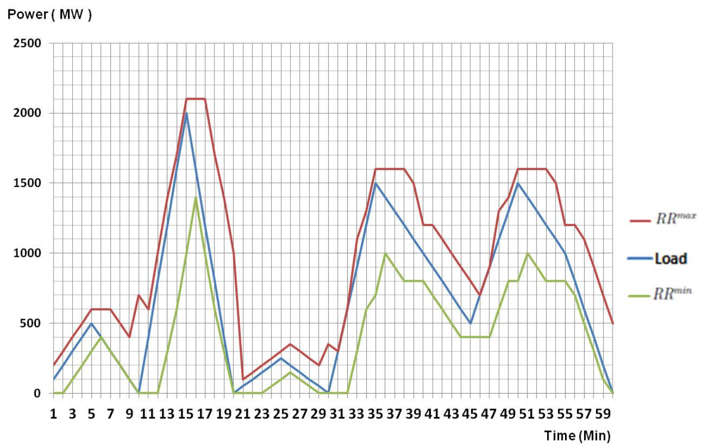

Figure 9: Reserve range RR for ISOPort$_2$ during hour H of day D

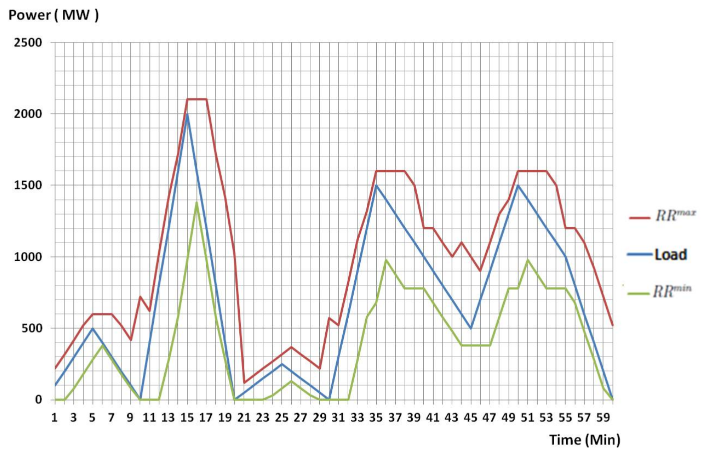

Figure 10: Reserve range RR for ISOPort$_3$ during hour H of day D

operating hour H, let Gen$_{i,M}$ denote the ZBG generation level (MW) of Gi at the start of M. Also, let $r^D_{i,M}$ / $r^U_{i,M}$ denote the down/up ramp-rate limits (MW/min) for Gi during M, and let $p^{min}_{i,M}$ / $p^{max}_{i,M}$ denote the min/max power limits (MW) for Gi at the end of M. Then the lower and upper bounds on the power levels that could be delivered by Gi at the end of M, conditional on its ZBG state at the start of M, are given by

$$\text{PI}^L_{i,M} = \max\{\text{Gen}_{i,M} - r^D_{i,M},\ p^{min}_{i,M}\} \ \geq \ p^{min}_{i,M} \qquad (13)$$

$$\text{PI}^U_{i,M} = \min\{\text{Gen}_{i,M} + r^U_{i,M},\ p^{max}_{i,M}\} \ \leq \ p^{max}_{i,M} \qquad (14)$$

The minimum power level RR_M^{min} attainable for the system as a whole at the end of minute M can be approximated by summing the lower power bounds (13) across the set G_H of GenCo suppliers Gi. Similarly, the maximum power level RR_M^{max} attainable for the system as a whole at the end of minute M can be approximated by summing the upper power bounds (14) across the set G_H of GenCo suppliers Gi. The reserve range RR_M at the end of minute M is then approximately given by the power-level interval between these summed lower and upper bounds:

$$\text{RR}_M = [\text{RR}_M^{min},\ \text{RR}_M^{max}] = [\sum_{i \in \text{G}_H} \text{PI}_{i,M}^L,\ \sum_{i \in \text{G}_H} \text{PI}_{i,M}^U] \tag{15}$$

and the RR over the entire hour H, expressed at the granularity of minutes, is approximately given by

$$\text{RR} \ = \ \{\text{RR}_M \mid M \in H\} \tag{16}$$

To illustrate in more concrete terms the determination of the RR for any given hour H, consider the following simple example. Let the net load profile for some operating hour H be as depicted in Fig. 4. Suppose the ISO is planning to achieve a ZBG for this net load profile by implementation of ISOPort_2 in (11) with GenCo suppliers G1, G2, and G3, where the dispatch levels for these GenCo suppliers are as depicted in Fig. 6.

Suppose the system is at the start of minute M=35 (or equivalently, at the end of minute M=34). The ZBG generation levels for G1, G2, and G3 are 400MW, 600MW, and 200MW, respectively. The down/up ramp-rate limits for G1 are $r_{1,35}^D = r_{1,35}^U$ = 100MW/min, and the min/max power limits for G1 are $p_{1,35}^{min}$ = 0MW and $p_{1,35}^{max}$ = 500MW. The down/up ramp-rate limits for G2 are $r_{2,35}^D = r_{2,35}^U$ = 200MW/min and the min/max power limits for G2 are $p_{2,35}^{min}$ = 0MW and $p_{2,35}^{max}$ = 700MW. Finally, the down/up ramp-rate limits for G3 are $r_{3,35}^D = r_{3,35}^U$ = 200MW/min and the min/max power limits for G3 are $p_{3,35}^{min}$ = 0MW and $p_{3,35}^{max}$ = 400MW.

Given these conditions at the start of M=35, the lower and upper power bounds attainable by each GenCo supplier at the end of minute M=35 can be calculated using (13) and (14), as follows:

$$\text{PI}_{1,35}^L = \max\{400MW - 100MW,\ 0MW\} \ = 300MW$$

$$\begin{aligned}
\mathsf{PI}^U_{1,35} &= \min\{400MW + 100MW,\ 500MW\} \ = 500MW \\
\mathsf{PI}^L_{2,35} &= \max\{600MW - 200MW,\ 0MW\} \ = 400MW \\
\mathsf{PI}^U_{2,35} &= \min\{600MW + 200MW,\ 700MW\} = 700MW \\
\mathsf{PI}^L_{3,35} &= \max\{200MW - 200MW,\ 0MW\} \ = 0MW \\
\mathsf{PI}^U_{3,35} &= \min\{200MW + 200MW,\ 400MW\} \ = 400MW
\end{aligned}$$

Consequently, the reserve range RR_{35} at the end of minute M=35 can be approximated using (15), as follows:

$$\begin{aligned}
\mathsf{RR}_{35} &= [300MW + 400MW + 0MW,\ 500MW + 700MW + 400MW] \\
&= [700MW,\ 1,600MW] \qquad (17)
\end{aligned}$$

The above method is used to derive the plots in Figs. 8-10 for the complete hour-H RRs for ISOPorts 1, 2, and 3 described in (10) through (12).

The GenCos can seek compensation for the RR characteristics of their RTM-offered GenPorts through their GenPort offer prices. In addition, GenCos with cleared GenPorts will be compensated ex post for any actual down/up energy they deliver during hour H, using the performance prices ϕ appearing among the contractual terms of these cleared GenPorts. This includes, in particular, compensation for any down/up energy needed to balance deviations between actual and ISO-forecasted real-time loads.

3.7 Practical Determination of Optimal ISOPorts

Let $\mathcal{L}$ = $\{\mathsf{L}_M \mid 1 \le \mathsf{M} \le 60\}$ denote the ISO-forecasted aggregate net load profile for hour H depicted in Fig. 4, expressed at the granularity of minutes M. Suppose the ISO's system-wide requirements for down/up reserve during H can be expressed in terms of the following restrictions on the lower and upper bounds of the reserve range RR corresponding to any ZBG ISOPort cleared to balance $\mathcal{L}$, where $\boldsymbol{\alpha}^* = (\alpha^{D*}, \alpha^{U*}) \ \ge\ 0$: For each minute M of hour H,

$$\mathsf{RR}^{min}_M \ \le\ [1 - \alpha^{D*}]\mathsf{L}_M \ \le\ [1 + \alpha^{U*}]\mathsf{L}_M \ \le\ \mathsf{RR}^{max}_M \qquad (18)$$

Suppose at least one feasible ISOPort achieves a ZBG for H. Then the ISO can formulate its RTM optimization problem as a multi-criteria optimization problem with three lexicographically-ordered objectives: (i) ensure a ZBG; (ii) ensure system-wide RR reliability at level $\boldsymbol{\alpha}^*$, i.e., satisfy condition (18) for the aggregate net load profile $\mathcal{L}$; and (iii) minimize the expected total cost of ensuring (i) and (ii).

More precisely, as schematically depicted in Fig. 11(a), the ISO can undertake the following three steps in sequence. First, determine the set $\mathcal{I}^{\mathcal{Z}}$ of all feasible ISOPorts that achieve a ZBG. Second, determine the (possibly empty) subset $\mathcal{I}^{\mathcal{Z}}_{\alpha^*}$ of $\mathcal{I}^{\mathcal{Z}}$ for which the RR requirement (18) is satisfied. Third, determine the subset $\mathcal{I}^{\mathcal{Z},\mathcal{MTC}}_{\alpha^*}$ of $\mathcal{I}^{\mathcal{Z}}_{\alpha^*}$ entailing minimum expected total cost, where this expected total cost consists of both GenPort procurement costs and expected ex-post GenPort performance costs for ensuring a ZBG that satisfies RR requirement (18). Any element of $\mathcal{I}^{\mathcal{Z},\mathcal{MTC}}_{\alpha^*}$ constitutes an optimal ISOPort selection for the RTM.

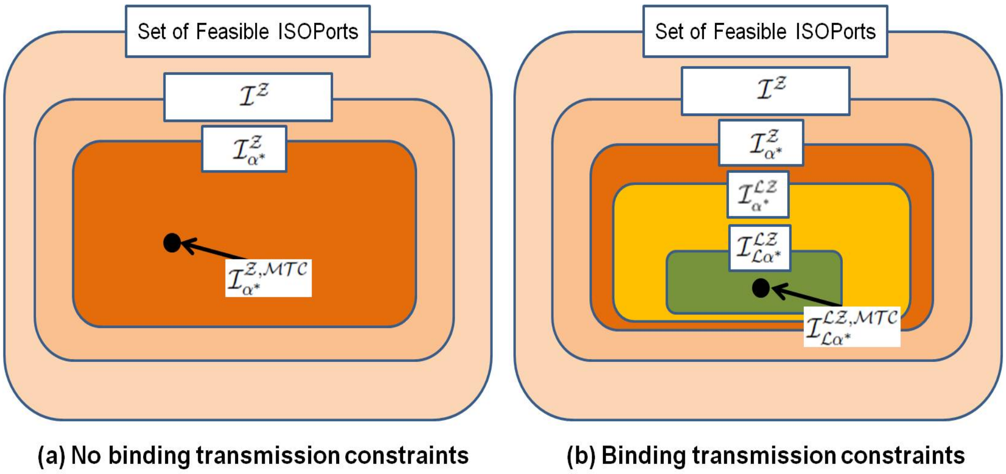

Figure 11: Depiction of the subsets $\mathcal{I}^{\mathcal{Z},\mathcal{MTC}}_{\alpha^*}$ and $\mathcal{I}^{\mathcal{LZ},\mathcal{MTC}}_{\mathcal{L}\alpha^*}$ of optimal (minimum total expected cost) ISOPorts subject to (a) system-wide ZBG and RR constraints in the absence of binding transmission constraints and (b) local ZBG and RR constraints in the presence of binding transmission constraints.

Relatively small values for (α^{D*},α^{U*}) in (18) might be needed to ensure the non-emptiness of $\mathcal{I}^{\mathcal{Z}}_{\alpha^*}$. For example, as depicted in Figs. 8-10, ISOPort$_1$, ISOPort$_2$, and ISOPort$_3$ can each achieve a ZBG that satisfies the RR$_{\alpha^*}$ constraint (18) when $\alpha^{D*} = \alpha^{U*} = 0$. However, only ISOPort$_3$ can achieve a ZBG that satisfies the RR$_{\alpha^*}$ constraint (18) when $\alpha^{D*} = \alpha^{U*} = 0.05$. Smaller values for α^{D*} and α^{U*} should also entail lower minimum total costs due to less need for swing in the cleared SCs. On the other hand, setting these values too small could jeopardize grid reliability if actual real-time net loads differ significantly from their forecasted levels.

3.8 Incorporation of Transmission-Line Limits

Until now, our RTM illustrative example has assumed an absence of transmission congestion. This simplification has permitted us to focus solely on the economic dispatch problem of ensuring a balance between aggregate dispatched generation and ISO-forecasted aggregate net load, subject to a system-wide RR_{α^*} constraint (18).

Consider, instead, an RTM for which the flow of power on each transmission line is subject to a potentially binding limit. In this case it is not sufficient to consider power and ramp-rate availability on a system-wide basis alone, since transmission congestion could limit the ability to move power from one bus to another. Rather, to ensure reliability, an ISO will need to impose a ZBG constraint at each bus, hereafter referred to as a *local* ZBG constraint.[5] Moreover, the ISO will also presumably wish to impose an RR_{α^*} constraint (18) at each bus, hereafter referred to as a *local* RR_{α^*} constraint.[6]

Note that a ZBG ISOPort satisfying a local RR_{α^*} constraint at each bus automatically satisfies a system-wide RR_{α^*} constraint. Consequently, as depicted in Fig. 11(b), the following nested relationships hold. The set $\mathcal{I}^{\mathcal{LZ}}_{\alpha^*}$ consisting of all feasible ISOPorts satisfying a local ZBG constraint at each bus and a system-wide RR_{α^*} constraint is a subset of $\mathcal{I}^{\mathcal{Z}}_{\alpha^*}$. Moreover, the set $\mathcal{I}^{\mathcal{LZ}}_{\mathcal{L}\alpha^*}$ consisting of all feasible ISOPort selections satisfying local ZBG and RR_{α^*} constraints at each

[5] Ignoring losses, the local ZBG constraint at each bus k is an equation ensuring that the total power injected at bus k equals the total power withdrawn at bus k plus the total power flowing out from bus k to other buses.

[6] In practice, local reserve requirements are imposed at the level of reserve zones. Roughly defined, a reserve zone is a grid region (buses plus connecting transmission lines) with normally negligible internal congestion that can on occasion operate as a load pocket because the transmission lines linking this region to other grid regions become congested. Load pockets can cause reliability problems if the generation capacity internal to the pocket is not sufficient to meet internal load. In this subsection, reserve zones are assumed to consist of singleton buses for ease of exposition.

bus is a subset of $\mathcal{I}^{\mathcal{LZ}}_{\alpha^*}$. Finally, the set $\mathcal{I}^{\mathcal{LZ},\mathcal{MTC}}_{\mathcal{L}\alpha^*}$ consisting of all optimal (minimum expected total cost) ISOPort selections for the RTM SCED optimization augmented with local ZBG and RR_{α^*} constraints at each bus is a subset of $\mathcal{I}^{\mathcal{LZ}}_{\mathcal{L}\alpha^*}$.

For example, as in Section 3.2, consider an RTM with three GenCo participants G1, G2, and G3 that takes place immediately before an operating hour H on some day D. Assume, now, that this RTM is operating over a 2-bus transmission grid with buses A and B, where G1 is located at bus A and G2 and G3 are located at bus B, and that the transmission line connecting buses A and B has a capacity limit of 1,100MW. As depicted in Fig. 4, the ISO-forecasted net load at the end of minute M=15 for hour H is L_{15}=2,000MW. Assume the ISO has forecasted that L_{15} will be divided into a net load LA=1,500MW at bus A, and a net load LB=500MW at bus B.

Suppose the ISO clears the $\mathrm{ISOPort}_3$ (12) in the RTM in an attempt to ensure a ZBG for hour H. The GenCo suppliers for $\mathrm{ISOPort}_3$ are G1, G2, and G3. Suppose the generation levels for G1, G2, and G3 at the start of minute M=15 are given by 400MW, 600MW and 600MW, respectively. Using the contractual terms of the SCs in $\mathrm{ISOPort}_3$, it can then be shown that the feasible power intervals for G1, G2, and G3 at the end of minute M=15 are as follows:[7] [280MW,500MW] for G1; [400MW,700MW] for G2; and [300MW,900MW] for G3.

Consequently, the selection of $\mathrm{ISOPort}_3$ permits the ISO to achieve a local ZBG at the end of minute M=15 with power flowing from bus B to bus A. Specifically, as depicted in Fig. 12, G1 at bus A can be dispatched at 500MW, which is its maximum possible power level. Also, G2 at bus B can be dispatched at 600MW, which is below its maximum possible power level of 700MW, and G3 at bus B can be dispatched at its maximum possible power level of 900MW. The net load LA=1,500MW at bus A exceeds by 1,000MW the 500MW of power generated by G1. However, the 1,500MW of power generated at bus B by G2 and

[7] Given $\mathrm{ISOPort}_3$, the down/up ramp-rate limits for G1, G2, and G3 during M=15 are $r^D_{1,15} = r^U_{1,15}$ = 120MW/min, $r^D_{2,15} = r^U_{2,15}$ = 200MW/min, and $r^D_{3,15} = r^U_{3,15}$ = 300MW/min. Also, the min/max power limits for G1, G2, and G3 at the end of M=15 are $p^{min}_{1,15}$ = 0MW, $p^{max}_{1,15}$ = 500MW, $p^{min}_{2,15}$ = 0MW, $p^{max}_{2,15}$ = 700MW, $p^{min}_{3,15}$ = 0MW, and $p^{max}_{3,15}$ = 900MW. These conditions, together with the assumed generation levels for G1, G2, and G3 at the start of minute M=15, determine the feasible power intervals for G1, G2, and G3 at the end of M=15. For example, for G1 this feasible power interval is given by [FPI^{min}_1, FPI^{max}_1] where $\mathrm{FPI}^{min}_1 = \max\{400MW - 120MW, 0MW\}$ = 280MW and $\mathrm{FPI}^{max}_1 = \min\{400MW + 120MW, 500MW\}$ = 500MW.

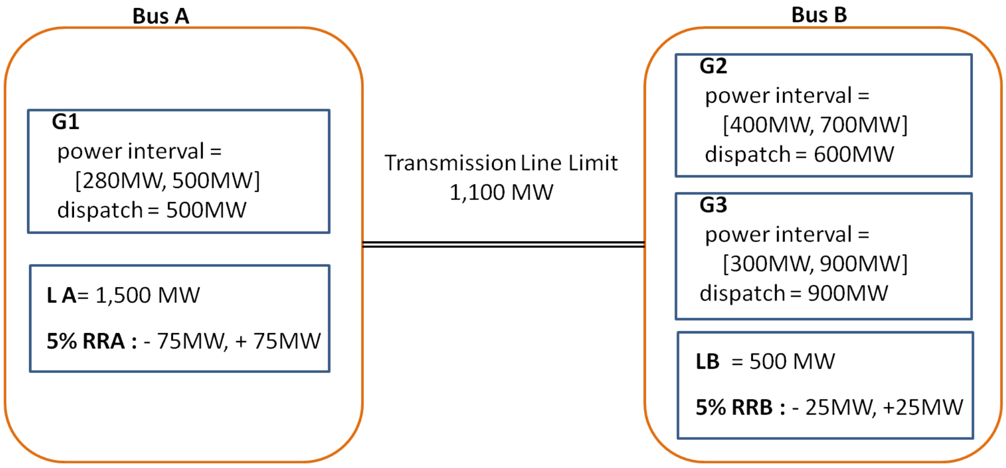

Figure 12: Depiction of an RTM ISOPort selection that satisfies local ZBG and RR_{α^*} constraints at each bus A and B at the end of minute M=15 for hour H of day D, where $\alpha^{D*} = \alpha^{U*} = 0.05$.

G3 exceeds the net load LB=500MW at bus B by 1,000MW; and this 1,000MW can be transferred from bus B to bus A to satisfy the remaining net load at bus A without violating the 1,100MW transmission line limit.

Now consider the additional RTM goal of ensuring a local RR_{α^*} constraint at each bus A and B at the end of minute M=15, with $\boldsymbol{\alpha}^* = (0.05, 0.05)$. To satisfy the 5% up-power requirements of these local RR_{α^*} constraints, the ISO needs +75MW of up-power reserve at bus A (5% of LA=1,500MW) and +25MW of up-power reserve at bus B (5% of LB=500MW). As seen in Fig. 12, the +75MW requirement at bus A is satisfied under $\mathrm{ISOPort}_3$ because G2 at bus B has +75MW of unencumbered up-power that can flow to bus A without violation of the transmission line limit. Moreover, the +25MW requirement at bus B is satisfied under $\mathrm{ISOPort}_3$ because G2 at bus B has +25MW of additional unencumbered up-power.

Conversely, to satisfy the 5% down-power requirements of these local RR_{α^*} constraints, the ISO needs -75MW of down-power reserve at bus A and -25MW of down-power reserve at bus B. As seen in Fig. 12, the -75MW requirement at bus A is satisfied because G1 can feasibly reduce its 500MW dispatch level to 425MW. Moreover, the -25MW requirement at bus B is satisfied because G2 and G3 can feasibly reduce their total dispatch level by 25MW, either separately or in combination.

4 Linkages between the RTM and the DAM

4.1 Overview

This section extends the RTM illustrative example presented in Section 3 to include the prior operations of a DAM, as depicted in Fig. 13.

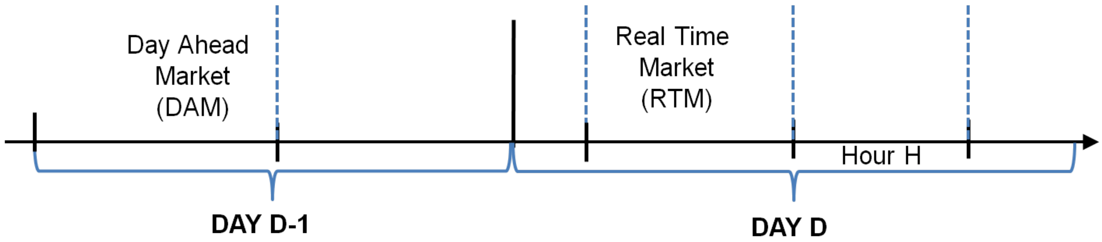

Figure 13: Illustrative time-line for DAM/RTM linkages

This DAM is assumed to operate in accordance with the general DAM description provided in Section 2.3. However, we maintain the simplifying assumptions introduced in Section 3 that load is not price responsive and that all line losses are negligible; and we also assume the absence of transmission congestion to further ease graphical depictions.

A key distinction between the DAM on day D-1 and the RTM on day D is that power-balance constraints in the DAM are based on LSE demand bids, not on the ISO's own forecasts for LSE-customer loads. LSE demand bids for hour H are assumed to take the form of constant non-price-responsive power levels, a simple block-energy form that greatly eases graphical exposition.[8] VER as-available generation during hour H is treated as negative load.

Nevertheless, the ISO managing the DAM has a fiduciary responsibility to balance *actual* real-time net loads to ensure grid reliability. Consequently, the

[8]Two-part LSE demand bids including both price-responsive and non-price-responsive portions, as in actual U.S. ISO-managed wholesale power markets, can be modeled by allowing each LSE to actively bid for multiple block-energy contracts at differing bid prices in addition to submitting a non-price-responsive block energy contract.

ISO is permitted to bid for SCs in the DAM on day D-1 to ensure reserve requirements are met, where these reserve requirements are informed by the ISO's own next-day net load forecasts.[9] The ISO then matches and clears DAM-submitted SC bids and offers to achieve a least-cost ZBG subject to system constraints and reserve requirements. The ISO subsequently enters into the RTM on day D with a record of all DAM-cleared SCs and conducts RTM operations conditional on this SC inventory.

The operations of the RTM for a particular operating hour H in the absence of SC inventory conditioning were illustrated in Section 3. This illustration will now be extended to show how RTM operations for hour H could be affected by SC inventory conditioning. Section 4.2 considers the case in which reserve requirements are entirely for regulation (load-balancing) purposes. Contingency reserve requirements are considered in Section 4.3.

4.2 DAM Linkages with Regulation Reserve Requirements

Let L_H denote the actual net load profile for hour H of day D, and let $L_H^{F,DAM}$ denote the ISO's forecast for L_H at the start of the DAM. Figure 14 illustrates how the DAM-cleared LSE demand bids (all in block-energy form) imply a constant power level for hour H that can deviate from $L_H^{F,DAM}$. The difference between the two represents the down/up regulation reserve that the ISO would need to procure in the DAM in order to expect to be able to achieve *actual* net load balancing for hour H, conditional on its own net load forecasts. Hereafter this difference will be denoted by $L_H^{NF,DAM}$.

In addition to net load balancing, however, the ISO needs to ensure that it satisfies DAM down/up regulation reserve requirements. Suppose these requirements take the form of a system-wide RR constraint (18) with $\boldsymbol{\alpha}^*_{DAM} = (0.10, 0.10)$. This means that the ISO must procure SCs in the DAM with sufficient swing (flexibility) in their contractual terms that they are capable of covering a corridor of potential net load profiles around the ISO's forecasted real-time net load profile $L_H^{NF,DAM}$ with a 10% width determined by $\boldsymbol{\alpha}^*_{DAM}$. This corridor, hereafter referred to as the *DAM 10% power corridor*, is depicted in Fig. 15.

[9]As in Section 2.3, we require all costs arising from the ISO's DAM SC procurement to be charged to market participants in order to preserve the ISO's non-profit status.

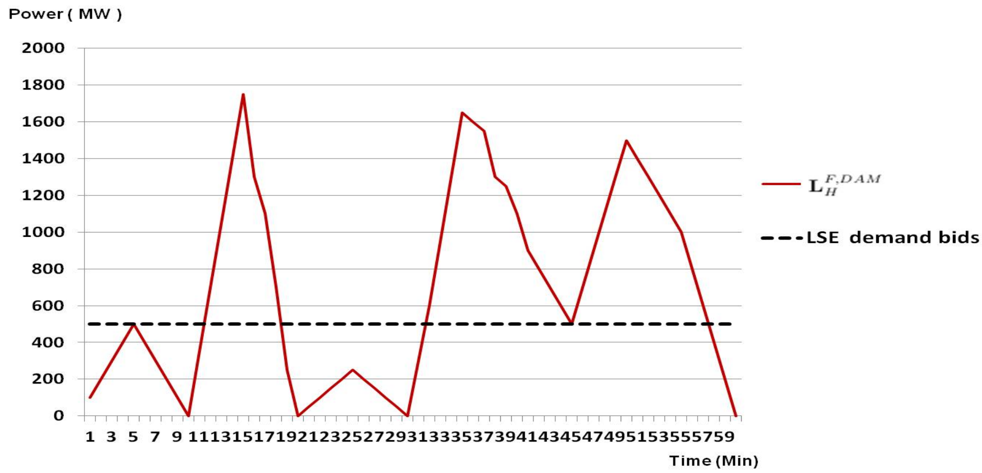

Figure 14: DAM-cleared LSE demand bids for hour H vs. the ISO's forecasted net load profile $L_H^{F,DAM}$ for hour H at the time of the DAM

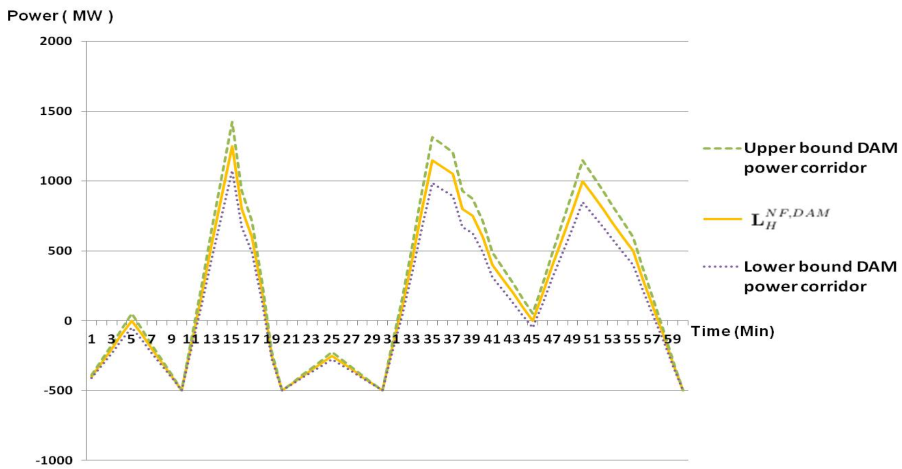

Figure 15: The DAM 10% power corridor for hour H of day D, conditional on the ISO's DAM-forecasted net load profile $L_H^{NF,DAM}$ for hour H of day D

As depicted in Fig. 16, the forecast $L_H^{F,DAM}$ that the ISO forms for L_H at the time of the DAM will typically differ from the forecast $L_H^{F,RTM}$ that the ISO forms for L_H at the time of the RTM.[10] For example, net load could be affected by uncertain weather conditions, and the ISO could have improved information about these weather conditions at the time of the RTM relative to the information

[10]Note $L_H^{F,RTM}$ in Fig. 16 coincides with the ISO-forecasted net load profile in Fig. 4.

available to the ISO at the time of the DAM.

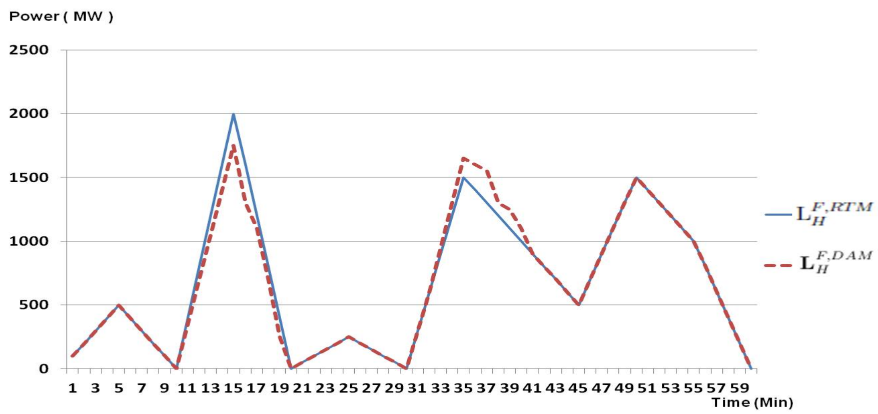

Figure 16: RTM vs. DAM ISO-forecasted net load profiles $L_H^{F,RTM}$ and $L_H^{F,DAM}$ for hour H of day D

The ISO's RTM objective is to ensure a least-cost ZBG for hour H of day D subject to regulation reserve requirements, conditional on its updated net load forecast $L_H^{F,RTM}$, GenCo/DRR/ESD RTM supply offers, and existing DAM-cleared SCs. Suppose the reserve requirements take the form of a system-wide RR constraint (18) with $\boldsymbol{\alpha}^*_{RTM} = (0.05, 0.05)$.[11] This means that the ISO must ensure, by the end of the RTM, that SCs have been procured with sufficient swing (flexibility) in their contractual terms that they are capable of covering a corridor of potential net load profiles around the ISO's forecasted real-time net load profile $L_H^{F,RTM}$ with a 5% width determined by $\boldsymbol{\alpha}^*_{RTM}$. Call this corridor the *RTM 5% power corridor*.

The gap G_M^L = [$PC_M^{L,RTM} - PC_M^{L,DA}$] between the lower bound $PC_M^{L,RTM}$ of the RTM 5% power corridor and the lower bound $PC_M^{L,DA}$ of the DAM 10% power corridor for minute M of hour H determines the down-power amount P_M^{down} the ISO needs to procure in the RTM for injection during minute M of hour H. Specifically,

$$P_M^{down} = \min\{G_M^L, 0\} \tag{19}$$

Similarly, the gap G_M^U = [$PC_M^{U,RTM} - PC_M^{U,DA}$] between the upper bound $PC_M^{U,RTM}$

[11]The ISO's net load forecast errors in the RTM can be expected to be smaller than the ISO's net load forecast errors in the DAM, and this is reflected in the specification of smaller component values for $\boldsymbol{\alpha}^*_{RTM}$ in comparison with $\boldsymbol{\alpha}^*_{DAM}$.

of the RTM 5% power corridor and the upper-bound $\mathrm{PC}_M^{U,DA}$ of the DAM 10% power corridor for minute M of hour H determines the up-power amount P_M^{up} that the ISO needs to procure in the RTM for injection during minute M of hour H. Specifically,

$$\mathrm{P}_M^{up} \; = \; \max\{\mathrm{G}_M^U, 0\} \tag{20}$$

Figure 17 illustrates the RTM down/up power requirements P_M^{down} and P_M^{up} that are implied by the lower and upper bounds $\mathrm{PC}_M^{L,RTM}$, $\mathrm{PC}_M^{L,DA}$, $\mathrm{PC}_M^{U,RTM}$, and $\mathrm{PC}_M^{U,DA}$ for each minute M of hour H. Note, for example, that no down-power procurement is needed in the RTM during minutes 10 to 20 of hour H because $\mathrm{PC}_M^{L,DA} < \mathrm{PC}_M^{L,RTM} \leq 0$ over this time interval. On the other hand, up-power procurement is needed in the RTM during minutes 10 to 20 of hour H because $\mathrm{PC}_M^{U,RTM} > \mathrm{PC}_M^{U,DA} \geq 0$ during this time interval.

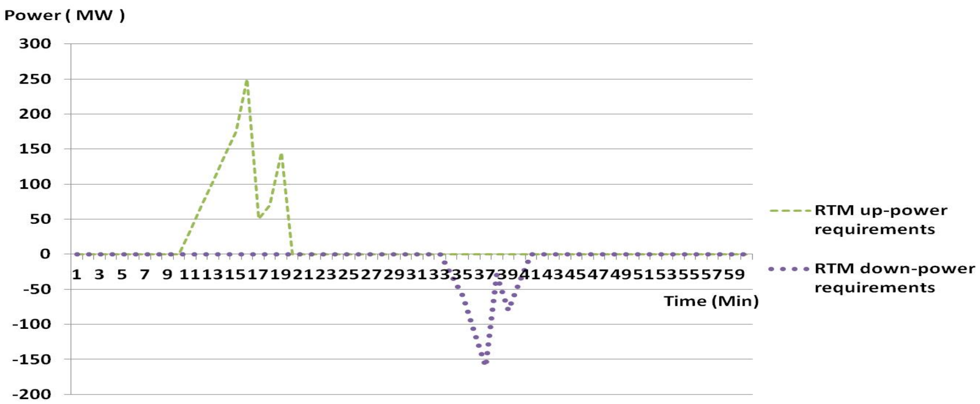

Figure 17: RTM down/up power procurement needed to satisfy net load balancing with a 5% RR constraint for hour H of day D, conditional on $\mathrm{L}_H^{F,RTM}$ and the DAM 10% power corridor

In summary, permitting linkages between the DAM and the RTM changes the form of the ISOPorts available for ISO selection in the RTM. For the illustrative example developed in Section 3, each ISOPort in the collection $\mathcal{I}_{\alpha^*}^{\mathcal{Z}}$ of ISOPorts achieving an RTM ZBG subject to the RTM RR constraint (18) for some given $\boldsymbol{\alpha}_{RTM}^*$ now takes the form

$$\mathrm{ISOPort} = \{\mathrm{GenPort}_1, \mathrm{GenPort}_2, \mathrm{GenPort}_3 \;\mid\; \text{Contract Inventory}\} \tag{21}$$

The *contract inventory* appearing in (21) consists of all SCs procured in the DAM whose exercise and/or use in combination with GenPort_1, GenPort_2, and GenPort_3 permits the achievement of an RTM ZBG subject to the RTM RR constraint. For comparative selection purposes, the relevant (i.e., avoidable) expected total cost of ISOPort (21) thus consists of two parts:

(i) the performance payments arising from the exercise and/or use of the SCs in the contract inventory to achieve an RTM ZBG subject to the RTM RR constraint;[12]

(ii) the portfolio offer prices and performance payments arising from the RTM-procurement and implementation of the SCs comprising GenPort_1, GenPort_2, and GenPort_3.

The RTM is a balancing mechanism permitting the contract inventory to be supplemented as needed with new SC procurement to achieve real-time net load balancing. As demonstrated in Fig. 17, the size of the RTM trade volume can be very small; it will tend to vary inversely with the amount of swing in the contract inventory.

Finally, under our proposed SC system, compensation obligations are separately incurred in the DAM (for service availability), in the RTM (for service availability), and in real time (for service performance). However, as illustrated in Fig. 18, the compensation obligations incurred for any particular operating hour H can in fact be settled at a single time point subsequent to H.

4.3 Contingency Reserve Considerations

Contingency reserve is spinning (synchronized) or non-spinning generation capacity that is able to reach a declared output level within a stated time interval in order to handle unusual power needs, such as the forced outage of a line or unit (Ellison et al., 2012). For resources with relatively slow ramp rates, the provision of contingency reserve through the RTM could be difficult if not impossi-

[12]Note that the SCs in the contract inventory have already been procured, hence their procurement costs are sunk (i.e., unavoidable) costs that should not affect the ISO's RTM selection of an ISOPort.

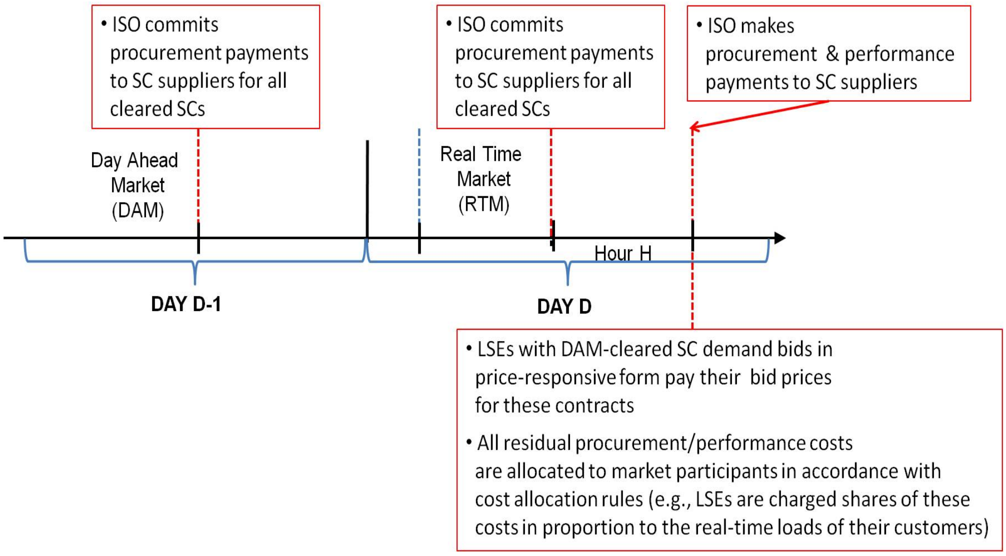

Figure 18: A possible time-line for hour-H settlements

ble. In addition, regulation reserve can be efficiently substituted for contingency reserve under some market and system conditions.

Consequently, we propose that the ISO be permitted to clear an appropriate combination of SCs in the DAM to satisfy reserve requirements for both normal and contingency operating conditions, in addition to meeting net load balancing needs. As for regulation reserve, we require all of the ISO's DAM procurement costs for contingency reserve to be charged to market participants in order to preserve the ISO's non-profit status.

For resources with must-run constraints ($p^{min} > 0$) as well as UC costs (e.g., no-load and start-up/shut-down costs), we anticipate that the ISO's contingency reserve procurement would largely occur through the procurement of SCs in option form. These types of contracts provide a "no exercise" option that could be used to save UC costs in cases in which updated ISO forecasts of system conditions render some contingency reserve unnecessary as an operating point approaches.

For resources with no must-run constraints ($p^{min} = 0$), there is no operational difference for the ISO in securing contingency reserve either through an SC in firm form or through an SC in option form as long as these SCs have identical contractual terms apart from exercise option(s). This follows because the ISO can choose to implement the SC in firm form at a power level $p = 0$, thus effectively achieving the “no exercise” option of the SC in option form. However, the non-profit ISO has a fiduciary responsibility to ensure efficient operation of the power grid. Early signaling of “no exercise” decisions to the issuers of SCs in option form might permit these issuers to direct their resources to alternative uses, thus avoiding lost opportunity costs.

5 Discussion

5.1 Comparison with Real-World TSO/ISO Operations

As indicated in Table 1, our ISO-managed DAM/RTM design for the support of SC trading is structurally similar to existing European and U.S. wholesale power market designs. European wholesale power markets include “spot” (day-ahead) and intraday markets for energy and reserve managed by TSOs operating on a non-profit-making basis (ENTSO-E, 2015; EPEX, 2015). U.S. wholesale power markets include day-ahead and real-time markets for energy and reserve managed by non-profit ISOs (EIA, 2015).

Moreover, the idea of permitting resources to offer options into TSO/ISO-managed wholesale power markets is not new. For example, Moriarty and Palczewski (2014) demonstrate how a small electricity storage unit could advantageously be permitted to offer American call options into a centrally-managed real-time imbalance market to facilitate net load balancing.

On the other hand, our SC system differs sharply from current TSO/ISO operations in other regards. SCs with swing function as intrinsically combined energy and reserve products permitting the provision of a wide range of flexibly-provided services. Also, rewards and penalties can be included in SC performance payment methods to encourage good service performance, e.g., accurate load forecasting and/or accurate following of dispatch instructions, where the rewards and penalties are assessed ex post based on actual performance. This inclusion could be required at the SC system level. Alternatively, SC suppliers could voluntarily undertake this inclusion as a way to signal the quality of their offered services to potential SC buyers.

Moreover, our SC system functions as a two-part pricing system under which all payments are compensations for value rendered, with no additional market or out-of-market payment adjustments required. Service *availability* compensation (in the form of SC offer-price payments) becomes obligatory at the commencement of service availability, i.e., as soon as SC supply offers are cleared. In contrast, service *performance* compensation (through SC performance payment methods) does not become obligatory until services have been performed in real time.

This two-part pricing system contrasts sharply with the Locational Marginal Pricing (LMP) systems currently implemented in U.S. ISO-managed wholesale power markets. Schweppe et al. (1988) conceptualized LMPs for *true* spot markets in which there is no separation in time between payment and delivery, not for forward markets such as DAMs and RTMs. Currently, DAM LMP payment commitments are made in advance for the anticipated real-time dispatch of DAM-cleared generation, that is, in advance of value received. They are then subsequently adjusted through RTM LMP payments to account for any deviations between DAM and RTM scheduled dispatch levels.

Moreover, DAM/RTM LMP payments do not necessarily provide adequate compensation for the costs incurred by resources to provide service availability. The perceived need to cover such costs more fully has led to the institution of capacity markets and various out-of-market uplift payments.

5.2 Comparison with Existing Standardized Power Contracts

The restructuring of European and U.S. electricity sectors, together with their increased reliance on VER generation, has resulted in increased price and volume risks for utilities and independent power producers as prices and net loads have become more volatile and difficult to forecast (Lemming, 2004). Financial and physical instruments are now heavily traded in Europe and the U.S. on exchanges and in over-the-counter markets as a means for hedging exposure to these risks (Äid, 2015; Deng and Oren, 2006; EEX, 2015; NYMEX, 2015).

In Europe, standardized power contracts have been developed by the Agency for the Cooperation of Energy Regulators (ACER, 2014). In the U.S., standardized power contracts have been developed by the Edison Electric Institute and the Western Systems Power Pool (EEI, 2014; WSPP, 2014). These widely used contracts are negotiated bilateral contracts between two counterparties.

Our proposed standardized contracts (SCs) differ in three important ways from ACER, EEI, and WSPP contracts. First, SCs are bids/offers for submission to an ISO-managed wholesale power market for possible clearing against other submitted offers/bids. In contrast, an ACER, EEI, or WSPP contract is a private agreement between two counterparties; it is subsequently self-scheduled in a TSO/ISO-managed wholesale power market only if fulfillment of the terms of the contract requires the use of power transmission lines.

Second, although the services provided through the contractual terms of SCs can cover the full range of product attributes included in ACER, EEI, and WSPP contracts, SC services are not rigidly separated into product types (capacity, reserve, and energy). Rather, SC services can be used to fulfill capacity requirements (general availability), reserve requirements (designated availability), and/or energy requirements (scheduled real-time dispatch) as appropriate.

Third, SCs permit swing (flexibility) in all of the services included in their contractual terms. In contrast, swing in ACER, EEI, and WSPP contracts is limited to option exercise dates in contracts taking an option form (ACER, 2014; EEI, 2014; WSPP, 2014).

5.3 Discriminatory vs. Uniform Pricing of Contracts

A market is said to exhibit *market efficiency* if the total net surplus extracted from the market by the market participants is at a maximum. Total net surplus is measured in practice as the sum of the differences between the buyers' maximum willingness to pay and the sellers' minimum acceptable payment for each successively traded commodity unit; see Stoft (2002) and Tesfatsion (2009).

In order for market efficiency to hold, all valued attributes of a market-traded commodity must be properly priced and compensated at the margin. In a day-ahead energy market organized as a bid/offer (double) auction, market efficiency can be achieved by means of a locally uniform pricing mechanism that assigns the same price to all energy units (MWh) being traded at a particular location for delivery at this location at a particular later time; see Tesfatsion (2009) and Li and Tesfatsion (2011). This is because the units of the traded product, characterized by physical type (energy), delivery location, and delivery time, are homogeneous.

However, a uniform pricing mechanism applied to a traded product does not necessarily result in market efficiency if the units of this product are not homogeneous. In particular, in a market for which buyers and sellers are submitting bids and offers for differentiated products – referred to as a *monopolistically competitive market* within economics – the buyers and sellers must be permitted to bid and offer differentiated prices for units of these differentiated products in order for these prices to reflect the true value of these units to buyers and sellers at the margin, a necessary prerequisite for market efficiency.

As discussed in previous sections, the SCs traded in our proposed DAM and RTM can be highly differentiated products. First, SCs can differ in terms of the types of services they offer. Second, even if two SCs offer the same types of services, the two SCs can differ in terms of the amount of swing included in the specification of these services. Consequently, our DAM and RTM are monopolistically competitive markets. The most appropriate pricing mechanism for SCs in our DAM and RTM is thus a discriminatory pricing mechanism in which SC sellers are permitted to offer differentiated prices for the sale of their differentiated products and SC buyers are permitted to bid differentiated prices for the purchase of these differentiated products.

5.4 Comparison with Existing VER Initiatives

A major development in European and U.S. TSO/ISO-managed wholesale power markets is that increased VER penetration is increasing the volatility of net load (i.e., load minus as-available generation). Some TSOs/ISOs are revising their market rules and product definitions to accommodate this development.

For example, as discussed by Navid and Rosenwald (2013) and Xu and Tretheway (2014), MISO and CAISO have each proposed the introduction of "flexible ramping" products. Also, as discussed by Seliga et al. (2013), ISO-NE has introduced a major rule change called "Energy Market Offer Flexibility." In addition, some ISOs are exploring innovative ways to incorporate VERs more fully into DAM/RTM operations. For example, MISO has introduced a new resource category called Dispatchable Intermittent Resource (DIR), designed primarily for its wind resources (MISO, 2011).

Our proposed SC system is not in conflict with the above market developments. To the contrary, as detailed in previous sections, SC trading would provide additional types of flexibility to both market participants and system operators that complement and extend these developments.

5.5 Robust-Control Management of Uncertain Net Load

A key requirement of standard two-stage stochastic SCUC formulations is the need to specify probability-weighted load scenarios with sufficient accuracy that a switch from currently-used deterministic SCUC formulations can be justified in terms of improved performance. For example, as shown in Krishnamurthy et al. (2015), given a simulated "true" load distribution and an approximate set $\mathcal{S}$ of load scenarios, a deterministic SCUC formulation can result in lower energy costs than a stochastic SCUC formulation based on $\mathcal{S}$ if reserve requirements for the former are set within a "sweet spot" range of values.

The rapidly growing reliance on VERs, resulting in increased net load uncertainty and volatility, has encouraged efforts to develop improved stochastic SCUC formulations based on *net* load scenarios. See, for example, Morales et al. (2009), Papavasiliou et al. (2011), and Vrakopoulou et al. (2013). However, these approaches rely on having an accurate modeling of the stochastic behavior of *net* load, a goal that has not yet been attained for as-available generation such as wind and solar power. In addition, to ensure tractability, they require the application of scenario reduction techniques capable of retaining the essential features of the net load scenarios derived from the original stochastic net load modeling.

Our proposed SC system offers an alternative robust-control approach to the management of uncertain net load. As detailed in Section 3, under this system the ISO considers in advance of an operating period how much swing (flexibility) will be needed in cleared SCs to cover a suitably wide corridor around an expected net load profile for this operating period. Consequently, a detailed specification of net load scenarios is not required.

5.6 Amelioration of Merit-Order and Missing-Money Issues

As noted in Section 5.4, centrally-managed wholesale power markets such as MISO are attempting to integrate VERs into the operations of their DAMs by permitting these resources to submit DAM supply offers based on generation forecasts. VERs tend to have relatively low marginal dispatch costs. Hence, increased VER participation tends to decrease the profits of thermal generators by reducing day-ahead energy prices, an outcome referred to in the power systems literature as the *merit-order effect* (Sensfuß et al., 2008). On the other hand, increased VER penetration requires an increase in flexibly-controllable generation to handle the resulting increased volatility of net load. Given the current state of electric energy storage development, this increase in flexibly-controllable generation must largely come from thermal generation.

The problem is then as follows. How can an adequate amount of flexibly-controllable thermal generation be ensured for matching the increased volatility of net load resulting from an increased penetration of VERs when the latter penetration reduces thermal generation profits and hence the incentive to invest in and maintain thermal generation?

This problem can be ameliorated by guaranteeing that thermal generators receive full compensation for all of the valuable services they provide, including flexibly-controllable generation. Our SC system permits this full compensation.

Specifically, under our SC system a thermal generator can offer a GenPort (i.e., a portfolio of SCs) that accurately expresses the types of services it can provide as well as the degree of flexibility (swing) with which each of these types of services can be provided. The generator should offer this GenPort at a price that fully covers the costs it would incur to ensure the availability of these services, including capital and lost opportunity costs. If the GenPort is cleared, the generator receives an immediate compensation commitment for service availability equal to the GenPort's offer price. The generator also receives ex-post compensation for any real-time services performed under the terms of the GenPort, where this ex-post compensation is determined by the performance payment methods appearing in the SCs that comprise the GenPort.

Another problem arising in centrally-managed wholesale power markets is *missing money*. Cramton and Ockenfels (2012) characterize this problem as follows: “In ‘normal’ periods, when there is no shortage of capacity, prices are below the level needed to cover operating and capital costs of new capacity, and in scarcity events, prices are unlikely to accurately reflect the scarcity.”

For concreteness, our current paper focuses on the support of SC trading through relatively short-horizon DAM and RTM operations. More generally, however, SC trading could be supported by a sequence of linked forward markets that includes longer-term forward markets with planning horizons spanning a year or more. In these longer-term forward markets, the two-part pricing of SCs would permit investors to receive availability and performance payments that fully cover their capital, lost opportunity, and operating costs, thus helping to resolve the missing-money problem.

6 Conclusion: Energy Policy Implications

Key policy implications of our proposed market-supported trading of standardized contracts (SCs) permitting swing (flexibility) in their contractual terms are noted throughout Sections 1 through 5. These policy implications are concisely summarized below:

(i) The SC system permits separate full market-based compensation for service availability and service performance

SCs can function both as standardized instruments for the procurement of service *availability* in forward markets and as standardized blueprints for the procurement of service *performance* in real-time system operations. Thus, SC trading supports the goals of FERC Order 755 (FERC, 2011); but this support is for a much broader array of services than envisioned in this order.

ii) The SC system facilitates a level playing field for market participation

The SC system focuses on service provision capability rather than on the physical characteristics of resources. This should permit and encourage the participation of a wider array of resources in wholesale power markets.

(iii) The SC system facilitates co-optimization of energy and reserve markets

SCs with swing intrinsically function as both energy and reserve products, eliminating the need to provide separate eligibility requirements and settlement processes for energy versus reserve services.

(vi) The SC system supports forward-market trading of energy and reserve

The *offer price* of an SC, determined through market processes, compensates the SC issuer for a guarantee of *service availability*. In contrast, the *performance payment method* of an SC, appearing among its contractual terms, determines how the SC issuer is to be compensated ex post for *actual services rendered* in real-time operations.

(iv) The SC system provides a fair way for all potential service providers to offer flexible service availability

SCs with swing permit the *providers* of these contracts to be compensated for flexibility in offered services, such as offered exercise times, begin-times, end-times, down/up ramp rates, and down/up power levels. Moreover, the ability of one or more resources to offer services in the combined form of an SC portfolio (GenPort) can enhance the ability of resources to obtain appropriate compensation for the full value of their services.

(v) The SC system provides system operators with real-time flexibility in service usage

SCs with swing permit system operators who *procure* these SCs to implement the services offered in these SCs in a flexible manner during real-time operations.

(vii) The SC system encourages accurate load forecasting and the accurate following of real-time dispatch instructions

Rewards and/or penalties can be incorporated into the performance payment methods ϕ appearing among the contractual terms of SC demand bids to encourage LSEs and other wholesale intermediaries who bid for services on behalf of retail customers to submit bids that accurately reflect the service needs of these customers. Similarly, rewards and/or penalties can be incorporated into the performance payment methods ϕ appearing among the contractual terms of SC supply offers to encourage service suppliers to follow real-time service performance instructions with high accuracy.

(viii) The SC system permits resources to internally manage unit commitment and generation-capacity constraints

By offering an SC for a particular operating period, a resource is guaranteeing that it can feasibly perform the services represented in this SC during this period. For generators, this feasibility includes the assurance that power generation units with suitable capacities will be synchronized to the grid as necessary to perform these services.

(ix) The SC system permits robust-control management of uncertain net load

Under the SC system, the ISO considers in advance of an operating period how much swing (flexibility) will be needed in cleared SCs to cover a suitably wide corridor around an expected net load profile for this operating period. The SC system thus provides a robust-control alternative to standard stochastic formulations for SCUC/SCED requiring detailed specifications of net load scenarios and scenario probabilities.

(x) The SC system eliminates the need for out-of-market payment adjustments

SC offer prices for service availability and SC performance payments for service performance provide full compensation for all rendered value, without need for additional market or out-of-market (OOM) payment adjustments.

(xi) The SC system reduces the complexity of market rules

Properties (i)-(x) reduce the complexity of power market rules, hence the opportunity for market participants to game these rules for their own advantage.

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Appendix

Table 1: Comparison between proposed SC system and real-world ISOs

<table>
<tr><th>ISO name</th><th>Product name</th><th>Contract form</th><th>Price determination process</th><th>Settlement</th><th>Changes under proposed SC system</th><th>Remarks on proposed SC system</th></tr>
<tr><td rowspan="4">CAISO</td><td>Capacity</td><td>Bilateral contracts</td><td>Bilateral contracts</td><td>Negotiated by counterparties</td><td rowspan="12">1. No rigid separation of capacity, reserve and energy products

2. SCs with swing can be used for capacity, reserve (various types), and energy

3. Cleared SCs are separately compensated for service availability and for service performance under a discriminatory-price mechanism

4. Service availability is compensated at time of SC procurement through SC offer prices and SC service performance is compensated ex post via SC performance payment methods</td><td rowspan="12">1. SC system does not limit bilateral trade between market participants

2. SC system uses discriminatory pricing for SC procurement while current centrally-managed markets use local uniform pricing for product procurement

3. SC system's two-part pricing attained by discriminatory price mechanism eliminates need for out-of-market make-whole payments</td></tr>
<tr><td>Regulation</td><td>DAM/RTM contracts</td><td>DAM/RTM co-opt process for reg., other anc. services, & energy</td><td>Capacity & performance payments (Order 755 compliance)</td></tr>
<tr><td>Other ancillary services</td><td>DAM/RTM contracts</td><td>DAM/RTM co-opt process for reg., other anc. services, & energy</td><td>Marginal pricing</td></tr>
<tr><td>Energy</td><td>DAM/RTM contracts</td><td>DAM/RTM co-opt process for reg., other anc. services, & energy</td><td>LMP pricing</td></tr>
<tr><td rowspan="4">ERCOT</td><td>Capacity</td><td>No capacity market</td><td>DAM/RTM scarcity pricing</td><td>LMP pricing</td></tr>
<tr><td>Regulation</td><td>DAM/RTM contracts</td><td>DAM/RTM co-opt process for reg., other anc. services, & energy</td><td>Marginal pricing</td></tr>
<tr><td>Other ancillary services</td><td>DAM/RTM contracts</td><td>DAM/RTM co-opt process for reg., other anc. services, & energy</td><td>Marginal pricing</td></tr>
<tr><td>Energy</td><td>DAM/RTM contracts</td><td>DAM/RTM co-opt process for reg., other anc. services, & energy</td><td>LMP pricing</td></tr>
<tr><td rowspan="4">ISO-NE</td><td>Capacity</td><td>Forward capacity market contracts</td><td>Capacity auction</td><td>Several-steps-ahead process to determine capacity settlements</td></tr>
<tr><td>Regulation</td><td>RTM contracts</td><td>RTM co-opt process for reg., other anc. services, & energy</td><td>Capacity & performance payments (Order 755 compliance)</td></tr>
<tr><td>Other ancillary services</td><td>Forward reserve market & RTM contracts</td><td>Forward reserve market; RTM co-opt process for reg., other anc. services, & energy</td><td>Marginal pricing</td></tr>
<tr><td>Energy</td><td>DAM/RTM contracts</td><td>Energy opt in DAM with reserve constraint; Energy co-opt with reg. & other anc. services in RTM</td><td>LMP pricing</td></tr>
</table>

ISO name	Product name	Contract form	Price determination process	Settlement	Changes under proposed SC system	Remarks on proposed SC system
MISO	Capacity	Forward capacity market contracts	Capacity auction	Several-steps-ahead process to determine capacity settlements		
	Regulation	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	Capacity & performance payments (Order 755 compliance)		
	Other ancillary services	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	Marginal pricing		
	Energy	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	LMP pricing		
NYISO	Capacity	Forward capacity market contracts	Capacity auction	Several steps ahead process to determine capacity settlements		
	Regulation	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	Capacity & performance payments (Order 755 compliance)		
	Other ancillary services	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	Marginal pricing		
	Energy	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	LMP pricing		
PJM	Capacity	Forward capacity market contracts	Capacity auction	Several-steps-ahead process to determine capacity settlements		
	Regulation	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	Capacity & performance payments (Order 755 compliance)		
	Other ancillary services	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	Marginal pricing		
	Energy	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	LMP pricing		
SPP	Capacity	Bilateral contracts scheduled in DAM	Load shares adjusted by self-provision	Invoiced by SPP		
	Regulation	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	Capacity & performance payments (Order 755 compliance)		
	Other ancillary services	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	Marginal pricing		
	Energy	DAM/RTM contracts	DAM/RTM co-opt process for reg., other anc. services, & energy	LMP pricing		