BALANCING AREA COORDINATION: EFFICIENTLY INTEGRATING RENEWABLE ENERGY INTO THE GRID

Coordinating balancing area operation can promote more cost and resource efficient integration of variable renewable energy (VRE), such as wind and solar, into power systems. This efficiency is achieved by sharing or coordinating balancing resources and operating reserves across larger geographic boundaries.

VARIABLE RE: CHANGING THE TRADITIONAL EQUATION

Power system operators maintain the balance of electricity supply and demand within geographic boundaries known as balancing areas.[1] In many countries multiple balancing areas are embedded within a single interconnection. Although rules may vary by location, each balancing area operator maintains this balance by committing—i.e., starting—generators in advance of when they are needed, then dispatching power from the available generators in combinations that minimize operating cost and maintain reliability. System operators must also hold adequate reserves to address variability and uncertainty of both generation and load, such as unscheduled plant outages.

The addition of VRE increases the challenge of matching the supply of generation to the demand of electricity consumers. The output of wind and solar adds both variability and uncertainty—this output varies over multiple timescales and adds an additional element of uncertainty due to the inability to forecast output with 100% accuracy. Operators may underpredict the availability of VRE and schedule too much generation, leading to too many generators running at partial output, which decreases efficiency and increases costs. Alternatively, operators may overpredict VRE availability and may not schedule adequate generation to meet the load. This may require the start-up of more expensive "quick start" power generators and, in extreme cases, may require steps to shed load, i.e., decrease demand to match the supply. Power system operators sometimes counter this uncertainty by increasing operating reserves, at added cost.

[1] U.S. balancing areas are formally referred to as "balancing authority areas.".

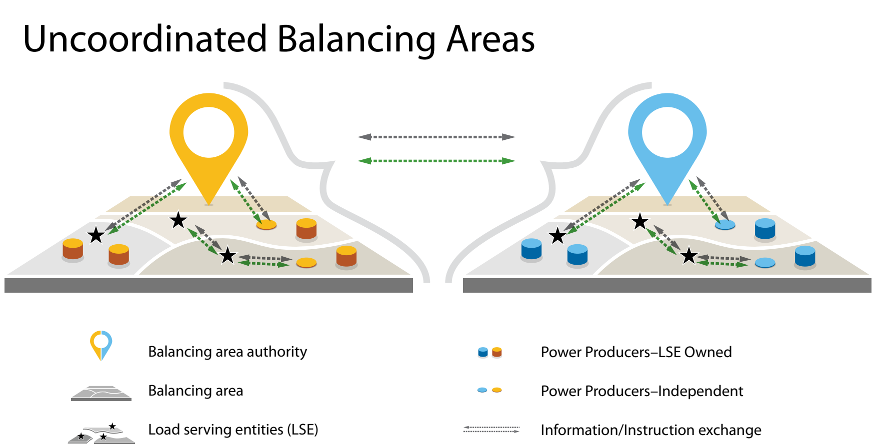

Figure 1: Without coordinated operation, exchanges of power and energy occur only through pre-negotiated bilateral contracts between the individual entities including balancing area authorities, load serving entities, and independent power producers.

GLOSSARY: TERMS RELATED TO BALANCING AREA COORDINATION

Automatic generation control (AGC): A regulatory mechanism and set of equipment that provides for automatically adjusting generation within a balancing area from a centralized location to maintain a specified frequency and/or scheduled interchange [8].

Balancing authority: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

Balancing authority area: The collection of generation, transmission, and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.

Bid-based centralized market: The framework for restructured electricity markets where all generators bid in costs to a centralized market operators. The generators selected for dispatch then receive a uniform clearing price based on the cost of the marginal generator.

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element [8].

Economic dispatch: The allocation of demand to individual generating units on line to effect the most economical production of electricity [8].

Frequency response: The ability of generation (and responsive demand) to increase output (or reduce consumption) in response to a decline in system frequency and decrease output (or increase consumption) in response to an increase in system frequency. Primary frequency response takes place within the first few seconds following a change in frequency. Secondary frequency response (also known as regulating reserve) takes place on a timescale of minutes (or faster) following a disturbance.

Interconnection: An independent electricity system network that operates at a particular frequency. An interconnection consists of one or more balancing area authorities that balance demand and generation within certain geographic areas of the interconnection.

Load serving entity (LSE): An organization that supplies energy and transmission to meet the electricity demand of its end-use customers. A utility is an example of an LSE. An LSE procures electricity from power producers, which operate electricity generating facilities, and which may be independent or owned by the LSE.

Operating reserves: Electricity generating capacity that is available to a system operator to provide for regulation (i.e., response to random movements during normal conditions), load forecasting error, forced and scheduled equipment outages, and local area protection. Other types of reserves include contingency (deployed in response to generator failures), regulating (secondary frequency response via AGC), or flexibility (reserves to address variability and uncertainty on timescales longer than regulating reserves).

Regional transmission organization (RTO): An independent entity responsible for maintaining system balance, reliability, and electricity market operation on the bulk system. The RTO allocates transmission rights based on a system of bids and offers, and optimizes unit commitment and dispatch decisions to minimize system costs. Other similar names for this function are Independent System Operator, or ISO (United States) and Transmission System Operator (Europe).

Unit commitment: The process of starting up a generator so that the plant is synchronized to the grid.

Traditional operational practices that limit the ability of different balancing areas to cooperate and coordinate resources over large areas increases the challenge of VRE integration. In particular, balancing areas often have limited ability to exchange power and energy with neighbors over various timescales to maintain balance of power supply and demand. Bilateral exchanges of power and energy sometimes occur between load serving entities (LSEs) and power producers (see Figure 1), but these transactions must be negotiated between individual entities and typically well in advance of the actual need.

FACILITATED COOPERATION: INCREASING OPERATIONAL EFFICIENCY AND REDUCING THE VARIABILITY RISKS

A variety of options exist to increase cooperation between balancing areas. These options give power system operators additional tools to more easily accommodate increased variability. A key benefit of cooperation is sharing variability and uncertainty. By sharing resources over larger geographic regions, net variability is typically reduced, which can produce multiple benefits, including reduced operating reserve requirements and reduced overgeneration and curtailment, which act to reduce overall costs of operation.

Figure 2 shows the typical balancing area operations, and three broad categories of cooperation at the operational level: reserve sharing, coordinated scheduling, and consolidated operation. These categories represent increasing levels of both coordination and complexity. Balancing areas can find additional benefits through coordinated planning [1].

Reserve Sharing

Reserve sharing refers to two or more balancing area authorities collectively maintaining, allocating, and supplying the reserves required for each balancing area. Reserve sharing is one of the simplest methods to minimize the economic impact of power system uncertainty, which increases with increasing VRE generation. Plant outages and random, short-term variation in supply and demand are relatively uncorrelated across large areas. Therefore, reserve requirements do not rise proportionally with the size of the system. By sharing reserves, multiple balancing areas can reduce total reserve requirements and lower system costs, while maintaining system reliability.

Reserve sharing groups can share different types of reserves. From simplest to most complex to implement, groups can share contingency reserves (deployed in response to generator or transmission line failures), regulating reserves (secondary frequency response via automatic generation control), or flexibility reserves (reserves to address variability and uncertainty on timescales longer than regulating reserves).

Reserve sharing is relatively simple to implement, and typically does not require complicated market transactions. Figure 3 illustrates new systems that must be put in place, primarily mechanisms (e.g., agreements, equipment) that send reserve dispatch instructions between neighboring balancing areas. The level of cooperation can vary according to the type of reserves being shared. In principle, reserve sharing can be done without any ongoing market transactions, particularly for contingency reserve sharing, where exchange of significant amounts of energy is relatively rare. As the energy exchanged between two balancing areas increases, for example with sharing of regulating or flexibility reserves, there is a potential need for increased tracking and financial compensation.

In areas without formal markets, the following steps can be used to evaluate the technical requirements for a reserve sharing group:

- Define type and technical parameters of reserve(s) to be shared.[2]

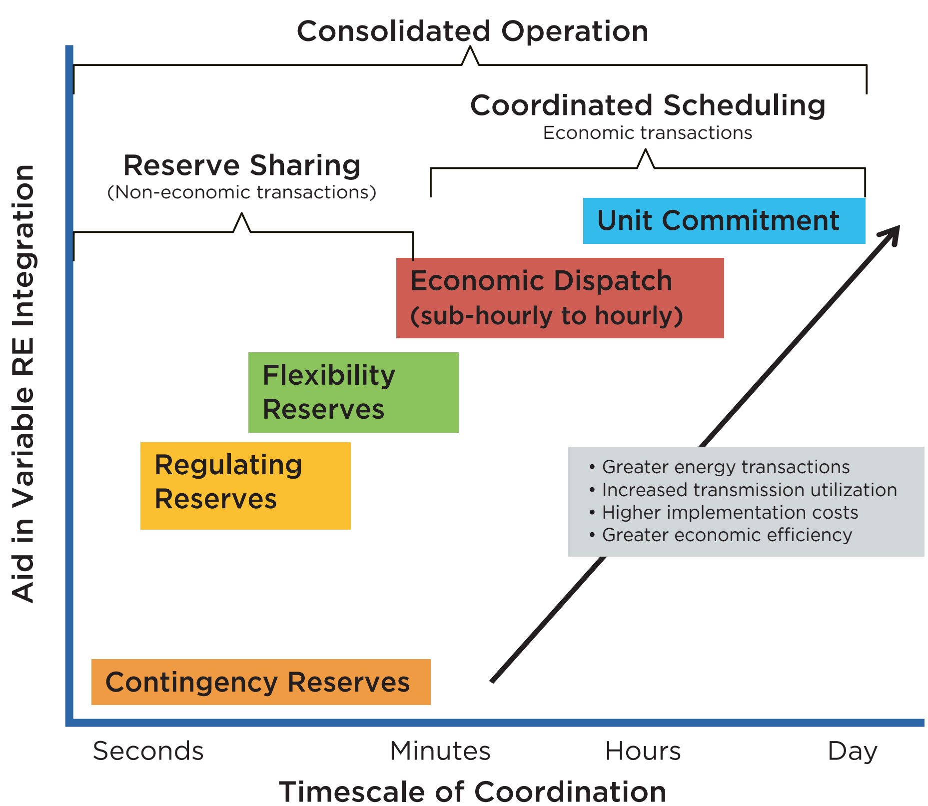

Figure 2: When balancing areas coordinate activities over longer timescales, they are able to increase the economic benefits of coordination to support VRE integration. However coordination over longer timescales introduces greater complexity and higher implementation costs.

[2]Types include contingency spin, primary and secondary frequency response, and flexibility reserves. Technical parameters includes synchronization requirement, time to begin response, time to reach full output, accuracy of response, and maximum duration of response.

Reserve Sharing

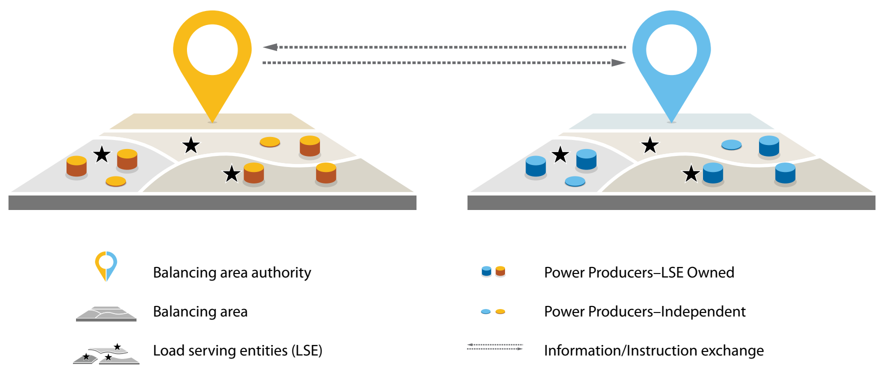

Figure 3: Reserve sharing requires additional coordination, such as exchanges of information. Extent of financial transactions depends on amount and frequency of energy exchanged. The figure illustrates the new systems that must be in place compared to the uncoordinated scenario.

- Estimate total reserve requirements across balancing areas. Because of spatial diversity, the total reserve requirement is often less than the sum of the individual balancing area reserve requirements [2].
- Allocate reserve requirement to each balancing area. This allocation can be based on the proportion of load and RE variability and uncertainty in each balancing area. In addition, this allocation should consider the relative frequency of contingencies, and the ability of the generation fleet in each balancing area to provide reserve services (for example: speed and accuracy of following an AGC signal; ability to hold output for required period).
- Estimate actual power flows that can occur at balancing area interfaces under various reserve sharing events. Compare the real power flows to transfer capacity, ensuring sufficient transmission exists to effectively share reserves. Monitoring systems can assist in ensuring adequate transmission capacity and alert system operators to reduce shared reserves when transmission capacity is insufficient.[3]
- Consider total annual flows of energy that may occur. As the amount of reserve sharing increases, there is a greater potential for energy exchange and associated costs. In this case, financial compensation mechanisms may be required.

Coordinated Scheduling

Coordinated scheduling refers to the process by which two or more balancing area authorities employ mechanisms to exchange energy over relatively short intervals, effectively minimizing the cost of electricity generation by sharing resources across larger regions.

Coordinated scheduling increases system commitment and/or dispatch efficiency. It extends the timeframe of coordination beyond short-term events, and increases the exchange of energy. Coordinated scheduling requires increased communication and planning compared to reserve sharing, and requires financial mechanisms to compensate participants for energy production.

Coordinated scheduling occurs on two general timescales:

- Short-term dispatch and load following, typically requiring scheduling intervals of 5-minutes to 1-hour
- Unit commitment, commonly occurring in the 24-hour time frame.[4]

Figure 4 illustrates two possible mechanisms to increase coordinated scheduling: a bid-based centralized market [3], and facilitated bilateral exchange via an electronic brokerage platform.[5, 6]

An example of a *bid-based centralized market* is an energy imbalance market (EIM), which can be particularly helpful in addressing unexpected changes to wind and solar generation. In an EIM, each LSE sends projected load and available capacity to the central market. The EIM operator then dispatches generators to produce electricity at least operating cost. An EIM addresses real-time energy imbalances as opposed to day-ahead scheduling requirements. In an EIM, day-ahead scheduling is still performed by the individual LSEs.

A bid-based centralized market can also occur at the timescale of unit commitment. However, due to the complexity in creating such markets for day-ahead transactions, unit commitment scheduling for multiple balancing areas is typically conducted as part of a full regional transmission organization/ independent system operator (RTO/ISO) market (see "Consolidated Operation"), rather than in isolation of reserve sharing and economic dispatch.

An alternative to the use of a centralized market is *facilitated bilateral exchanges* through an electronic brokerage platform. This approach does not truly optimize dispatch, but it does allow cost savings across multiple timescales—from scheduling to dispatch—without the complexity of a central market. In this case, requests for and offers of power are shared through the brokerage platform. Buyers and sellers of electricity agree to a transaction, and financial transactions are handled bilaterally. The reservation of transmission capacity can be performed separately, or can be integrated into the electronic brokerage platform.

Key steps to institute coordinated scheduling include:

- Establish a system for continuous information exchange of generator availability and costs.

[3] Additional discussion provided in [4]

[4] While typically performed day-ahead, unit commitment can be performed in shorter intervals, allowing for the adjustment of short-startup-time units such as some combined cycle gas units.

[5] There are multiple names for this entity. Examples discussed in [5] and [6].

[6] Another option for coordinated scheduling is dynamic scheduling, where a generator or load is virtually moved from one balancing area to another by changing the way the metering of balancing is configured.

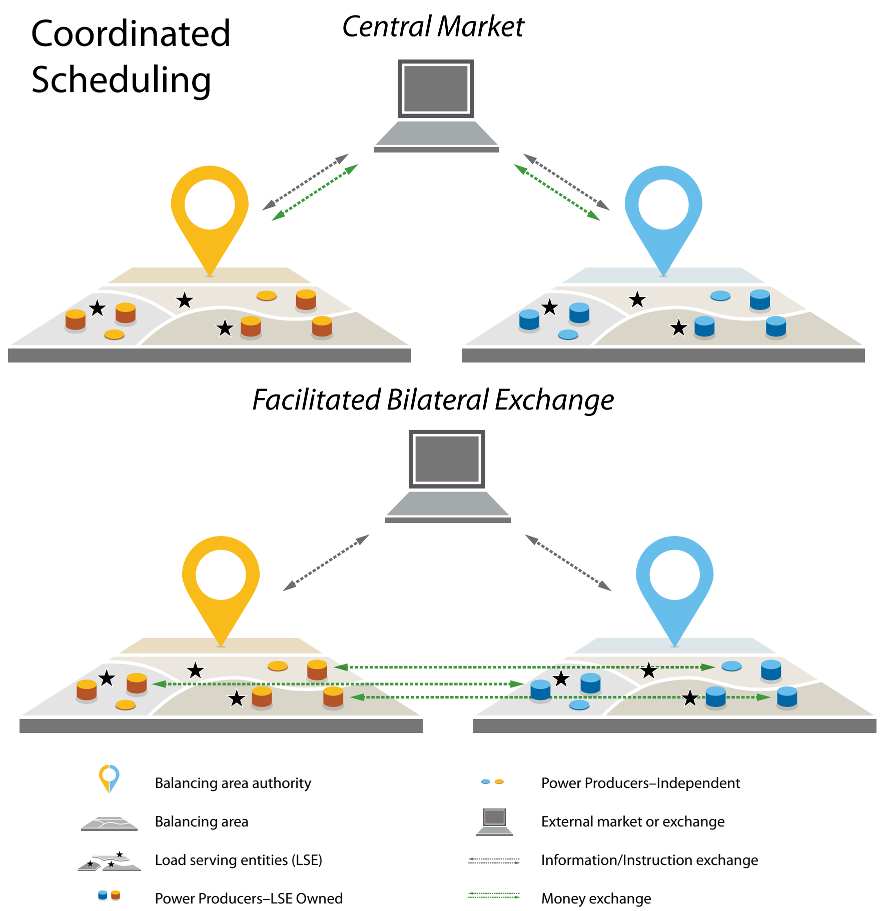

Figure 4: Simplified illustration of the additional mechanisms required to increase short-term coordination between balancing areas. In this example, new information exchanges are required via a centralized (top) or bilateral exchange (bottom) market. Mechanisms for financial transactions are also required for the centralized market.

- Create a monitoring system and financial compensation mechanism for energy exchanges and transmission usage.

- Establish a means to calculate transmission adequacy on relevant timescale(s). This requires a transmission system owner/ operator or some other organization to perform analysis of power flows and provide information about transmission availability to participants.[7]

Consolidated Operation

Consolidated operation is the merging of two or more balancing areas into a single operational entity, for example, under an RTO/ISO. Consolidated operation combines all stages and timescales of system operation including unit commitment, economic dispatch, and reserves provision, while considering transmission adequacy and tracking the provision of energy from all individual generators. This type of operation also facilitates the appropriate compensation for generators providing energy and ancillary services.

Consolidated operation provides all of the benefits of reserve sharing and coordinated scheduling, and co-optimizes the generation fleet for maximum economic benefit and least-cost VRE integration.

Options for consolidated operation include:

- Physical consolidation as a vertically integrated entity (a single balancing area authority with direct control over operations)

- Physical consolidation under an RTO/ISO market structure (a single balancing area authority running a market with multiple participants)

- Virtual consolidation.

Figure 5 illustrates physical consolidation.

Physical consolidation as *a vertically integrated entity* can occur under the traditional regulatory framework where two or more balancing areas merge to create a new, larger balancing area authority.

Physical consolidation under an RTO/ISO market structure occurs when the balancing area authority does not own generation, but coordinates generator scheduling based on characteristics of individual generators that bid into the market. In the evolution of market coordination, shorter-term EIMs, as discussed in the previous section, are often introduced before unit commitment (day-ahead) markets. This is because dispatch is somewhat less complicated (requiring changes only to generator output as opposed to commitment changes), requires less regulatory and political change (the original LSE maintains responsibility for scheduling during the transition), and eases the transition to scenarios where RTO/ISOs have established "full" control over plant commitment, dispatch, and provision of reserves.[8]

Key steps to establish an RTO/ISO market structure include the elements described in coordinated scheduling, a complete system of governance, and market monitors to examine and mitigate potential market power issues.

It is possible to create coordinated operation without physical consolidation. This concept, which has been referred to as *virtual or partial consolidation* [4], requires creating cooperative agreements. Under a cooperative agreement, a newly created operating entity would co-optimize system commitment and dispatch, and ensures transmission adequacy. Conceptually, this would appear similar to the institutional structure of Figure 4 (coordinated

[7]There are multiple mechanisms for doing this, including markets or a real-time transmission availability system [7].

[8]This transition allows local LSEs and generators the ability to maintain control over unit scheduling as they become more comfortable with market operations. Examples include the Electric Reliability Council of Texas and the Southwest Power Pool, which started with real-time energy markets and later added day-ahead (unit commitment) markets.

scheduling, such as through an EIM) but across longer timescales than is typical for coordinated scheduling to include unit commitment. The operating entity could include a bid-based market, bilateral based market, or other structures that appropriately compensate generators for operation.

SUMMARY

Increasing coordination between balancing areas can positively impact the integration of VRE into the power grid. This paper discuss three general classes of coordination: reserve sharing, coordinated scheduling, and consolidated operation.

Reserve sharing is both common and relatively easy to implement. Sharing of reserves can aid in minimizing the impacts of wind and solar's uncertainty. Reserve sharing often has relatively low implementation costs, particularly since many reserves have relatively small energy requirements. This minimizes total energy exchanges that occur between neighboring balancing areas, and reduces the need to establish mechanisms to track energy flow and allocate costs, although transmission adequacy still needs to be ensured.

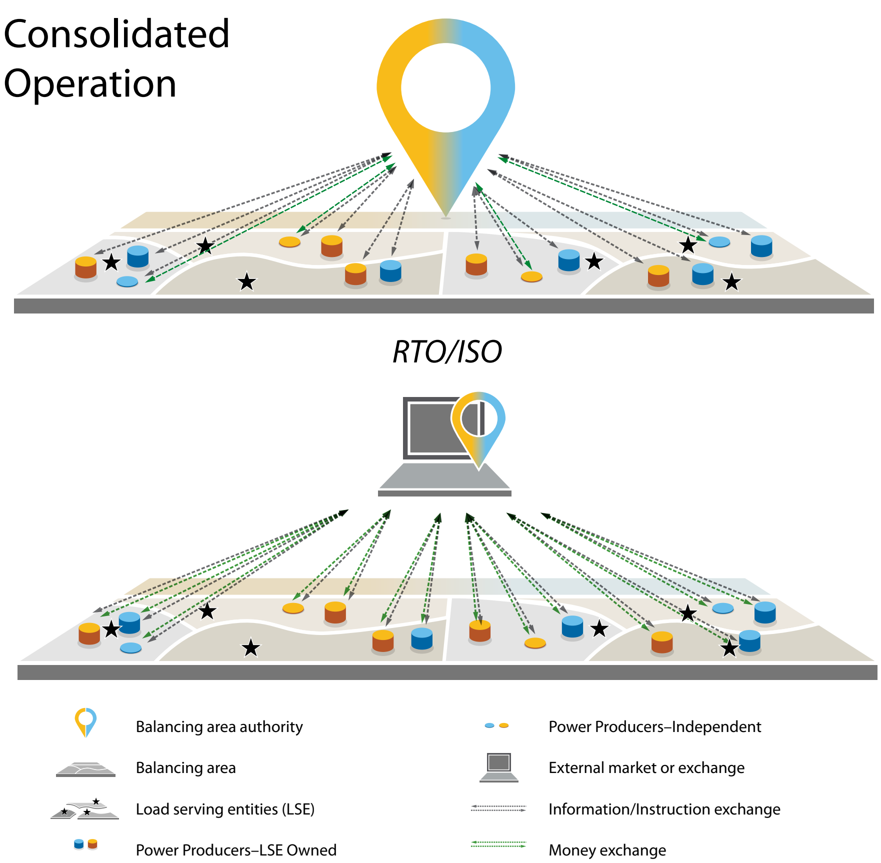

Figure 5: Physical consolidation options, including consolidation under vertical integration (top) or under an RTO/ISO (bottom), can increase efficiencies of operations with variable generation.

Mechanisms for Increasing Balancing Area Cooperation Fall Into Three Major Classes

The answers to the questions below reflect typical situations, and do not characterize all cooperation within reserve sharing, coordinated scheduling, and consolidated operation

	Reserve Sharing	Coordinated Scheduling		Consolidated Operation	
		Market-Based	Facilitated Bilateral	Vertical Integrated	RTO/ISO
Does this structure typically change the responsibility for scheduling and/or dispatch instructions?	No.	Yes. In a real-time or EIM, each balancing area (BA) is still responsible for unit commitment. New market entity performs supplemental economic dispatch for energy imbalance.	No. But scheduling is informed by facilitated bilateral exchange.	Yes. New vertically integrated entity.	Yes. New RTO.
Typically, are the data sharing requirements for the BA voluntary?	Yes.	No.	Yes.	N/A: The BA (RTO or vertically integrated entity) holds all data, which is provided by independent power producers and load-serving entities in the BA.	No. Mandatory data is submitted to the market operator by all entities within the BA.
What data do the coordinating BAs typically share?	Reserves requirements; basic characteristics of the power system.	Generator characteristics of available capacity.			
What is typically needed for transmission scheduling?	Power flow estimates that can be used to set caps on reserve sharing.	Transfer capacity at relevant timescales to make dispatch decisions. The Open Access Same-Time Information System (OASIS) is an example of a tool to communicate transmission availability.		Transmission operator (RTO or BA authority) schedules both generation and transmission.	
Does role of LSE typically change under this structure?	No.	Yes. Any LSE that acted as a BA gives up some scheduling responsibility.	No.	Yes. Any LSE that acted as a BA gives up that responsibility.	Yes. Any LSE that acted as a BA gives up that responsibility.
How are costs discovered?	Long-term bilateral contracts.	Marginal price based on bid-based auction.	Bilateral contracts.	Self-owned plants and independent power producers with long-term contracts.	Bid-based auction (e.g., marginal price or pay-as-bid).

Coordinated scheduling allows for much greater energy exchange, increasing overall economic efficiency, and providing increased ability to integrate VRE in the power system. Coordination can occur for shorter time-frame operations (generator dispatch; five minutes to an hour in advance) or longer time-frame operations (generator commitment; typically 24 hours in advance). The increased benefits are accompanied by increased implementation costs, as energy exchanges require creation of mechanisms to track energy purchases and flows, which can be accomplished via multiple market mechanisms (both bid-based and market-facilitated bilateral agreements). Transmission analysis becomes essential to maintaining system reliability.

Finally, consolidated operation across all timescales produces the greatest benefits in terms of overall economic efficiency and ability to integrate greater amounts of VRE at least cost. This can require creation of new market entities, such as an RTO, or it can be accomplished administratively, such as through a vertically integrated entity, in which a transmission provider procures the resources necessary to balance the system.

There is often a tradeoff between benefits and complexity when considering balancing area cooperation mechanisms. The three mechanisms discussed here actually consist of many individual options that can be tailored to local conditions and existing system requirements, ownership structures, and regulatory requirements. The benefits realized through improved coordination benefit not only the integration of VRE, but improve the system operation overall.

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Greening the Grid provides technical assistance to energy system planners, regulators, and grid operators to overcome challenges associated with integrating variable renewable energy into the grid.

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