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Electric Grid Market-Control Structure

June 2017

JD Taft

U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

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Acknowledgments

The author wishes to gratefully acknowledge the many discussions with Paul De Martini and Lorenzo Kristov that contributed greatly to the thinking in this paper.

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1.0 Background

Markets and controls are frequently portrayed as being polar opposites, incompatible alternative paradigms, or even competing philosophies for organizing the activities of large complex systems. In the electricity industry in the US prior to the 1990s, the dominant organizational structure was the vertically-integrated utility, characterized by a well-defined geographic and electrical service territory and the ownership or control of most generating facilities,[1] a transmission network, local distribution systems and a monopoly over retail electric service for most if not all of the end-users in the territory. A vertically-integrated utility, many of which still exist today, operates mostly on controls with very little scope for markets or market transactions.

In the 1990s federal laws and regulations prompted a major restructuring of the industry to enable wholesale competition among generating companies. To that end wholesale markets were created in several regions of the country to facilitate the development of competitive wholesale energy markets and to optimize the use of transmission systems. As such, in the several regions with independent system operators there is a prevailing view that markets are a core component of the 21st century electric system. Markets are seen by some as vastly superior to command-and-control regimes in terms of economic efficiency. Consequently, the role and application of controls have thus been pushed to the edges of many industry discussions except that the operators of grids and generating plants still depend on controls such as plant governors, automatic generation control, and automatic regulation systems to maintain reliable operation.

From an architectural perspective, it is clear that markets and controls can and must coexist, even in the most market-oriented electric systems. Only through the complementary roles and functions of markets and controls can complex large-scale systems like the regional interconnected power systems of North America fulfill the societal objectives they are intended to serve.

This paper analyzes the markets and control systems for the electric power grid and show how their interactions are embodied in a set of combined or integrated "market-control" structures. It provides a logical way to examine the bounds of each such structure by mapping them into a two-dimensional space defined by the number of end points or participants and the needed update or refresh rate of the essential functions these structures must perform. For the control engineer, this paper shows how to view markets as tools for power system management; for market economists this paper shows how controls connect markets to physical systems. These issues are increasingly important as the industry moves toward the integration of high penetration level of DERs.

For the control engineer, this paper shows how to view markets as tools for power system management; for market economists this paper shows how controls connect markets to physical systems.

For the purposes of this paper, a control is a means to direct, regulate, or stabilize the behavior of a physical device or system. A control system consists of a device or system to be controlled, a device that directs the desired behavior ("controller"), methods for determining appropriate control signals to elicit the desired behavior from the system ("control algorithms"), and means of communication for sending control signals to the control elements that drive the system and may include sensing and measurement feedback to the controller. The word "control" by itself will refer to the method for determining control signal; the term "controller" will refer the device or devices that compute or otherwise determine control signals. For *simple* device and system controls, the thing being controlled will always respond (within

[1] The 1978 PURPA introduced customer onsite co-generation in the 1980s.

physical limits) to the control command or signal and that the control mechanism determines the behavior to be commanded.[2] For control of stochastic systems, the situation is more complex. In this case the overall system can be controlled to behave in a statistical sense, even if individual elements are not guaranteed or even known to behave in a particular manner. Consider the example of a nuclear reactor: the overall power output can be controlled even though it is not possible to predict, control, or even know when any specific atom will undergo fission. A well-known example from electric system operation is a demand response virtual resource comprised of thousands of residential air conditioners, whose aggregate behavior can be reasonably well controlled to be acceptable although the behavior of the individual devices is not predictable.

For decentralized systems, the control devices, controllers, sensors and actuators, and connections to devices or systems being controlled constitute a control network. Understanding the network concept in relation to the power system network and other grid structures such as markets (where they exist) is important to understanding the structure of distributed and layered grid control and coordination mechanisms.[3]

A market, for purposes of this paper, is a physical or virtual place where buyers and sellers choose to interact to trade goods, services, contracts, or financial instruments for money or barter. A market typically involves **means for communicating the attributes of the item** between **buyers and sellers**, for **agreeing on exchange prices and quantities**, and **for effecting physical delivery**. A *market system* incudes not just the market platform, but market operator and the buyers and sellers as well. Buyers and sellers choose to interact and at any point may choose not to complete the transaction (and thus may incur penalties) or to complete it in a manner different to their earlier agreement. While market economists may view control systems as not having this property, in fact, as the discussion above has shown, for control systems with large numbers of individual end point elements the net behavior is essentially the same – it is not possible to predict what a given elements will do but the overall aggregated response may still be well-behaved and acceptable. In this sense, designing market rules and determining market prices by operating a market is analogous to designing control laws and calculating control signals by operating a controller.

Electricity markets are of two main types: spot markets and bilateral markets.[4] Spot markets involve multiple buyers and sellers submitting bids and offers, and the process of market clearing results in market signals, i.e., cleared quantities and prices, that indicate to the participants how to proceed, but do not involve direct relationships between individual buyers and sellers. In contrast, bilateral markets result in contracts between individual buyers and sellers that typically specify a quantity, price, time and location of delivery. In addition, markets generally have some form of enforcement mechanism that imposes consequences – typically financial – on parties to an exchange for failure to fulfill their part of the agreed transaction; e.g., on a buyer who fails to make payment or a seller who fails to deliver on time. It is not possible to know in advance with certainty whether any particular party will in fact participate or perform as the market clearing indicates, but when there are sufficient participants the overall statistical behavior of the market is predictable under normal circumstances.

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[2] Certain distributed control schemes involve cooperation among separate control elements, but the cooperation is defined algorithmically and is not discretionary on the part of those elements. In some formulations, penalties in the form of cost functions are employed to ensure proper behavior or even correct behavior in real time.

[3] J Taft, P De Martini, R Geiger, Ultra-Large-Scale Power System Control and Coordination Architecture, June 2014, available online: http://gridarchitecture.pnnl.gov/media/white-papers/ULS%20Grid%20Control%20v3.pdf

[4] Spot electricity markets in the U.S. include ISO and RTO operated markets such as those of PJM. Bilateral markets are those that facilitate bilateral transactions between parties such as the Intercontinental Exchange (ICE).

The set of market participants, the market mechanism, and associated infrastructure including communication networks, constitute a financial network. Understanding the market as a network is necessary to understand network convergence issues[5] involving markets, controls, and grids, and to understand distributed transactive energy approaches to markets.[6]

[5] P De Martini and J Taft, Value Creation Through Integrated Networks and Convergence, Feb 2015, available online: http://gridarchitecture.pnnl.gov/media/advanced/Electric%20Networks%20%20Convergence%20final%20version%20%20Mar%2015%202015.pdf

[6] JD Taft, Architectural Basis for Highly Distributed Transactive Power Grids: Frameworks, Networks, and Grid Codes, June 2016, available online: http://gridarchitecture.pnnl.gov/media/advanced/Architectural%20Basis%20for%20Highly%20Distributed%20Transactive%20Power%20Grids_final.pdf

2.0 Complementary Views of Markets and Controls for Electric Power Systems

In the electric utility context, there are two seemingly disparate views of how grids should be operated, one based on market concepts, and one based on control concepts. In this paper we shall discuss the limitations in each of these views, provide insights into both and show why they are complementary and valuable.

The market view is essentially this:

> Markets can manage all grid functions. Just get the right market rules and right price signals and everything will work efficiently and reliably.

The control view is essentially this:

> Controls can manage all grid functions. Just set up and solve the right optimization equations and everything will work efficiently and reliably.

The mathematical methods and solution tools used by electric grid market operators are essentially the same as those used in optimal control methods. This is not really surprising; both have roots in optimization theory and represent formulations of similar or even the same problem from slightly different points of view. Dispatch problems can be and are solved today using either market methods or optimal control methods. At a mathematical level, the formulations are essentially equivalent.

As an example, consider the unit commitment problem. A few decades ago operators used fixed priority orders for unit start-up and shutdown. This evolved into dynamic priority order and, in 1996 the standard became dynamic priority order sequential bidding. Enhanced Lagrangian relaxation was introduced in 2001 to support this optimization, and mixed-integer programming came into use in 2003. In 2013, market optimization benefited from AIMMS 3.13 (Advanced Interactive Multidimensional Modeling System, a software package designed to model and solve large-scale optimization and scheduling problems) and CPLEX 12.5 (an optimization software package accessible through AIMMS). These approaches and tools will be very familiar to control engineers who use optimal control methods.

Markets are presumed to operate voluntarily and do not take into account physical system behavior; no methods exist to derive market rules from a physical system model or to ensure the "right" set of prices will be determined by a market. Controls are presumed operate imperatively and do not take into account human behavior; no methods exist to derive controls from a human system model or to ensure that the "right" set of behavioral incentives will be determined by a control system. A deep examination of markets and controls as applied to power grids at the bulk system shows more similarities than differences and also shows that they are essentially complementary in nature, suggesting that they can and should compensate for each other's limitations.

> Power grid markets and controls are essentially complementary in nature, suggesting that they can and should compensate for each other's limitations.

3.0 Control Engineers: How to Think About Electricity Markets

A problem with the pure control formulation for grid control with massive DER is that control systems have no means to obtain some of the information needed to support the optimization equation formulations, such as objectives and constraints of DER owners. In addition, the amount of data that can be needed to solve large scale control problems for high penetration of DER presents a communication network scalability problem. Markets can help the control engineer resolve these issues by acting as:

- Sensors – markets are sensors for data not obtainable through engineering transducers; specifically data on the time-varying objectives and constraints of the owners of generation and DER assets
- Data aggregators/compressors – markets also serve to aggregate and compress the data listed above (into the extremely compact forms of bids and clearing signals)
- Optimization engines – markets provide optimization solutions as mentioned earlier. These optimizations may be incorporated inside grid control loops or may be used in supervisory control modes

Electricity markets are <u>distributed systems</u>. Electricity markets are often referred to as organized central markets, but in these cases it is the *market platform that is centralized*, not the market itself.[1] Looking again at the market definition above, it is clear that there are many decentralized elements (the buyers and sellers) that coordinate (via the market mechanism) to solve a common problem (power balance). In the case of DER integration, some of the approaches, notably the Transactive Energy approaches, can involve distribution-level *distributed market platforms*.

For the control engineer, markets can provide tools to deal with the complex problem of coordinating high penetration mixed DER in multi-party environments with multiple time varying objectives and constraints that cannot be measured or modeled by traditional engineering methods.

[1] A distributed system is one in which multiple decentralized and essentially autonomous elements cooperate to solve a common problem. This implies some form of coordination, be it via market or control methods. Market bidders are the autonomous elements and the market process is the coordination mechanism.

4.0 Market Economists: How to Think About Electric Grid Control Systems

A problem with the pure market formulation for grid operation is that markets have no means to ensure that market solutions comport with the electrical physics of the grid and thereby not cause reliability problems. This issue became evident in the early development of markets for bulk energy systems, leading to the need to introduce locational marginal pricing, which connects the physical grid and its control systems to the markets.

Control systems obtain physical measurements to be used as feedback for the controller. This same information can be used to inform market mechanisms about physical conditions on the grid. An example of this is using grid state estimation based on physical grid sensing and telemetry to compute locational marginal prices to enable markets to deal with transmission congestion. In addition, there are grid functions that must operate on very short time scales, too short for markets, so these functions are implemented as pure controls but may be supervised (by providing set points) or may be enabled by markets (by procuring resources used by the control systems).

In the bulk energy systems where organized markets exist, the degree of coupling of the electric markets and grid control systems is quite extensive, to the point where it is not actually possible to separate them. Consequently, in this paper we shall refer to these mechanisms as *market-control systems*, rather than separate market systems and control systems.

In bulk electricity systems with organized markets, the markets and grid control systems are extensively coupled, so that they should be thought of as joint market-control systems, not separate entities.

5.0 Market-Control Regimes for Bulk Power Systems

Grid operation has evolved to use methods that combine both markets and controls. We shall view the existing bulk system market-control arrangement in terms of five elements defined by function, operational time scale, and component parts. Later this paper will examine the market-control structures that implement these elements and the limits associated with each.

1. Control of generation, power interchange, and sharing of inter-BAA resources within and between Balancing Authority Areas (BAAs) in the US where Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs) operate involves a multi-level arrangement: the lowest level (primary generator control), each generator has local closed loop control and the set of generators connected to a transmission grid uses droop control and system inertia to solve the load sharing problem;
2. Load frequency control (secondary generator control) uses a single closed loop for the entire BAA to adjust generation and power interchange with neighboring BAAs so as to regulate system frequency;
3. Supply-demand balance and interchange are handled by five and fifteen minute (typically) markets inside closed loop receding horizon controls (tertiary generator control);
4. Unit commitment and scheduling are handled on a day-ahead or multi-day-ahead basis, and sometimes on an intra-day basis; and
5. On a much longer-term basis (months to multiple years ahead), capacity markets (centralized auctions or bilateral contracts) are used to authorize and commit generation assets to be available for use in the controls listed above. In some instances a multi-year forward commitment may require the construction of a new generation asset.

Figure 1 below depicts the key market and control mechanisms employed at the bulk energy system level in an ISO or RTO in a slightly simplified manner. In this arrangement there are functions that are handled by controls only, functions that are handled by markets only, and functions that combine markets and controls closely. Note that the set of market participants shown for one market may not be the same as the set for another, although typically there are overlaps. We shall decompose this diagram into component market-control elements in order to fully understand the structures.

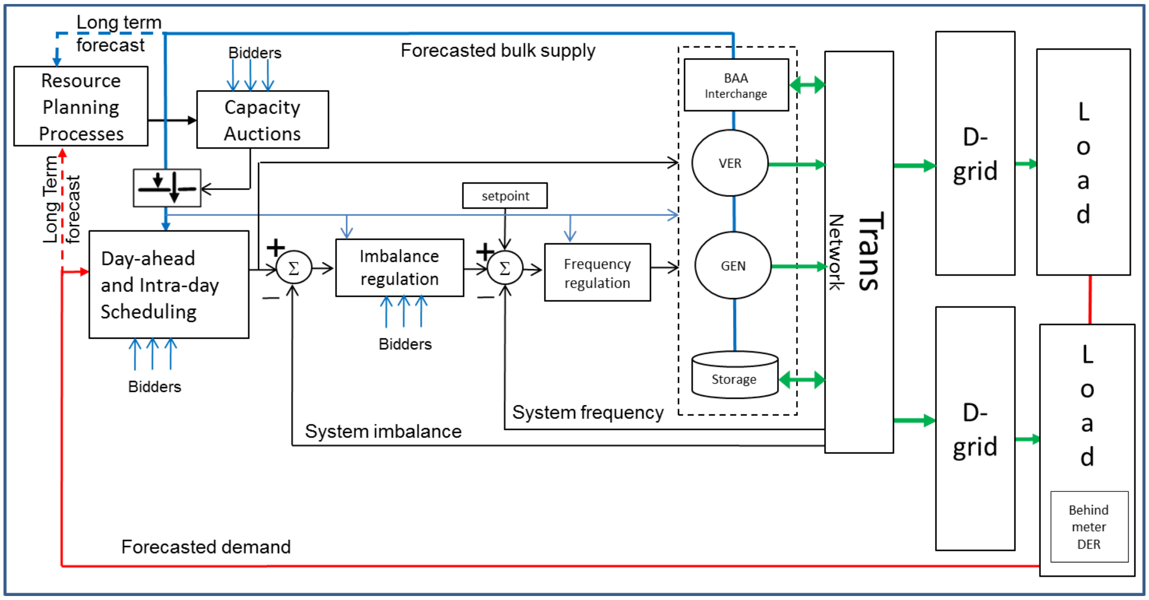

Figure 1. Simplified View of Bulk System Markets and Controls

The model just described works well and has been extended in some places to enable participation in the bulk energy market by certain Distributed Energy Resources, especially Demand Response (DR), for purposes such as system peak limiting and energy usage time shifting, variable generation following, and an expanding array of ancillary services. Of growing interest is how such models might be applied to the emergence of high-DER-penetration distribution systems with possible Distribution System Operator (DSO) markets,[1] none of which exist in the U.S. today. Existing market-control methods have evolved more or less organically at the bulk system level, and while they are highly functional, the principles of market-control structure and interaction are not widely recognized outside a limited community. Further, these principles must undergo some modification for application to the operation of a high-DER distribution system and an integrated T&D grid.

[1] P. De Martini and L. Kristov, Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight, October 2015, available online at: https://emp.lbl.gov/sites/all/files/FEUR_2%20distribution%20systems%2020151023.pdf

6.0 Electricity Markets and Controls: Essential Relationships

In electric power systems, both market mechanisms and control systems are used. In some cases, the markets and controls retain their separate identities and characteristics, even when they have some connection with each other. However, for organized central real-time markets, the market and control networks have converged, resulting in a platform upon which new value streams can and have been implemented, in accordance with the principles of network convergence.[1] This platform includes the real time markets as optimizing elements within a receding horizon control loop,[2] such that new value streams are easily implemented by defining new market products, as is happening in California with storage services for the grid.

To better understand electric system market-control relationships, consider the basic relationships involving markets and control, and the resulting key structures. This analysis presumes specific implementations for the relevant markets and control systems, meaning that data collection, control and market algorithms, and computational facilities are in place and operational. While it is obvious that control is pervasive throughout the grid, it is less obvious that that markets and controls can work together in certain combinations and for certain ranges of performance variables, and that there are regimes of these performance variables where market mechanisms are not applicable, so that only traditional control mechanisms can be applied. Two key variables that characterize how markets and controls for the grid can be integrated are the update rate of the market, control, or combination, and the number of endpoints (devices being controlled, market bidders, etc.) participating in the control or market processes. The regimes of applicability for markets and controls may be charted to illustrate the underlying relationships. It is possible and useful to relate system planning processes to the market-control regimes on this same chart.

The purpose of this representation is to answer two basic questions:

1. How do electric system markets and controls impact each other and where does each apply?
2. What happens to an existing market or control regime when the number of endpoints (or participants), or the required update rate, increases significantly?

Figure 2 below shows the regions of support chart for two classes of markets – real-time and forward- as well as control systems. In this paper, the dividing line is whether the market mechanism operates in a supervisory mode in relation to the control system or as parts of the real time control loop(s). Typically, we group the five minute, fifteen minute, and hourly markets in the real time category, with the day-ahead and forward markets placed in the supervisory category. For completeness, the region of support for longer-term annual transmission and distribution planning is also included.

[1] Paul De Martini and Jeffrey D. Taft, Value Creation Through Integrated Networks and Convergence, available online at http://smart.caltech.edu/papers/ElectricNetworksConvergence_final_022315.pdf
[2] JD Taft and A Becker-Dippmann, Grid Architecture, available online at http://energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20Grid%20Architecture_0.pdf

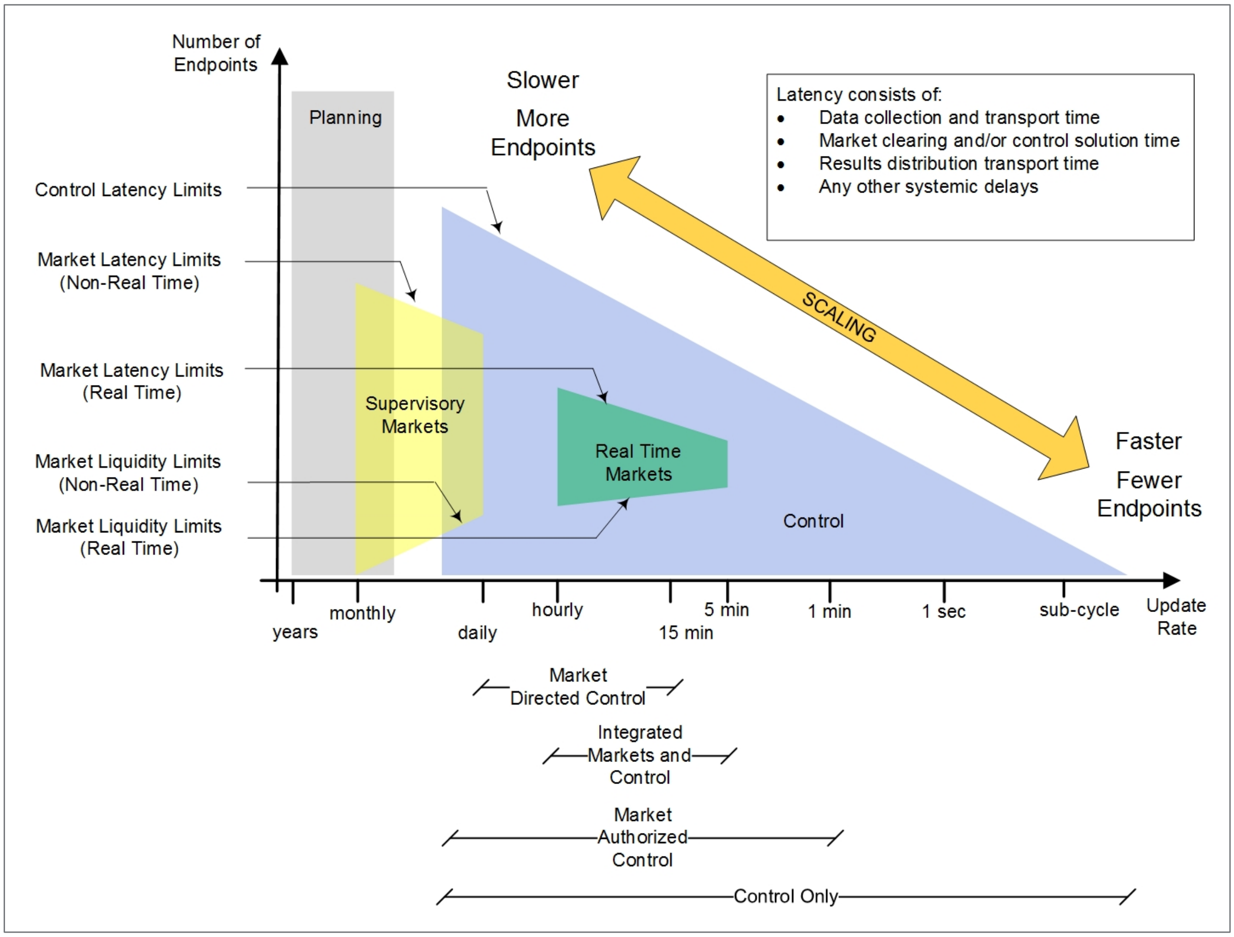

Figure 2. Regions of Support for Electric System Markets and Controls

Note that update rate is essentially a measure of temporal granularity, with faster updates corresponding to finer grain. The diagram allows us to identify three types of market-control combination, plus a fourth mode where only control is used, all of which are described below.

The diagram illustrates a number of principles, enumerated below.

6.1 Principle of Market Participant Limits

Any given market implementation has both lower and upper bounds on the number of participants that can be involved. The lower bounds are not implementation dependent; rather they are market illiquidity limits. The upper bounds are due to algorithm complexity growth – as the number of participant increases, the market solution computation time increases until it finally reaches the update rate (cycle time) limit for the specified market. While this has not been an important issue for existing bulk system markets, the proposed vast number of the participating DER endpoints makes this a real consideration. At that point, either the market cycle will slow or a new market implementation will be required. For example, decreasing the size threshold for market participation will exacerbate the complexity by increasing the number of potential participants. The CAISO has recently reduced the size threshold to 500kW to allow more market participants, for example. Conversely, aggregation of DER by service providers can virtually reduce the number of dispatch points. These market structural factors along with additional computation assets, new market algorithms, or a change from centralized to distributed forms that support greater scalability than centralized ones do may all come into play. In any event, a specific market implementation has an upper limit on participants that depends in part on the market update rate.

6.2 Principle of Control System Endpoint Limits

Similarly, control systems have upper limits on endpoints. The reason is essentially the same as for markets – with increasing numbers of endpoints, at some point any given control system cannot maintain its update rate, so either the update rate must decrease or some change in the control system must be made. Control systems do not have a lower endpoint limit of the type that markets have.

6.3 Principle of Market Update Rate Limits

The update rates shown for markets in Figure 2 represent bounds for any particular fixed implementation. It is technically feasible to move some of these bounds, but for substantial reasons such as nonlinear growth of computational complexity and therefore computational time on a given hardware platform, there are still limits on, for example, update rates for real time markets. These granularity limits depend on a combination of technical and business value elements, but are nevertheless, very real. See the section on Granularity Considerations below for more detail.

6.4 Principle of Control System Update Rate Limits

Control systems used in utility grid applications have update rates that vary over a much larger range than markets do. Depending on the type of control, update rates can span from very slow (unit commitment) to very fast (sub-cycle down to even microsecond level for power electronics like electronic stabilizers, flow controllers, and solar inverters). A key aspect of the control system region of support is that, for any given control structure or mechanism, the maximum number of endpoints is a declining function of update rate, so that at very fast rates, a few or perhaps only one endpoint is involved (e.g. control of a DSTATCOM voltage compensation system that updates at a sub-cycle rate, say, four milliseconds), whereas, for slower rates (say, the typical four second SCADA cycle) the number of points may be large (numbered in the tens of thousands). When we consider processes such as distribution capacitor control, generator unit commitment, and seasonal grid configuration, we see that there are control system applications for which the update rates can be quite slow, measured in anywhere from minutes to months.

7.0 Market-Control Regime Structures

Regardless of where the exact (implementation dependent) boundaries of the regions of support are, Figure 2 above indicates several interaction regimes that further imply corresponding market-control structures.

7.1 Basic Grid with Local Control and Regulation/Stabilization

Figure 3 is a simple model of the core an electric grid system, which can be used to represent a distribution system, a transmission and bulk generation system, or a whole BAA. Each device (bulk generators and storage, DG, DR, DS) has local controls, such as the primary generator controls used at the bulk system level or local controls for building energy management or storage control, for example. The figure can also be used to represent microgrids. We shall use this basic model to illustrate the various market-control structures individually and in concert.

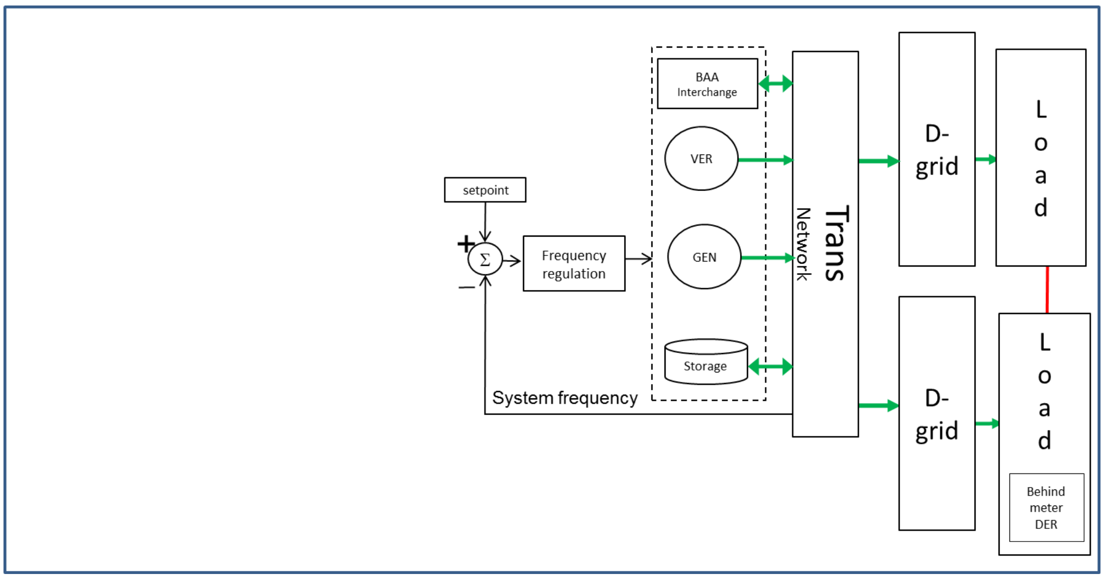

Figure 3. Basic Electric System

In addition to the basic local device controls, the model also includes a real time feedback loop for system frequency regulation. At the bulk system level, the feedback loop corresponds to load frequency control (secondary generator control); at the distribution level feedback loops provide feeder Volt/VAr control and may also provide stabilization (example: DSTATCOM stabilization of distribution feeder voltage). The outputs of the system being controlled comprise the grid state, which may include power flows, voltage profiles, phase angles, and system frequency as appropriate. The set points are fixed or very slowly varying supervisory inputs that tell the control loops what value of a given parameter (voltage, say, or frequency) the local controls are to maintain. The circuit switches and flow controllers used to direct power flows are not shown in this model.

The model is deliberately simple but sufficient to illustrate the market-control structures that follow.

7.2 Market Directed Control

Figure 4 shows the Market-Directed Control structure model connected to the basic grid model. Market-directed control consists of market functions that provide schedules or other directives to a control system or systems. The results of the market clearing provide the sequence of set points that will be used to operate the system over a relatively long period, absent any unanticipated changes in grid operating conditions. **Dispatch of generation and other power resources is market directed control.**

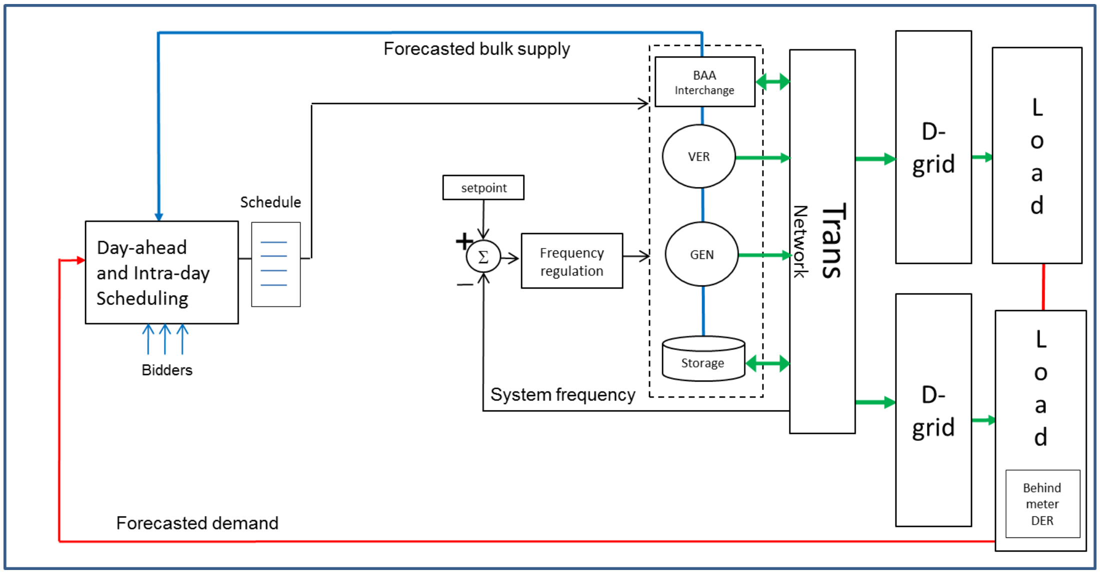

Figure 4. Market Directed Control

In market-directed control, the markets exists outside of the primary and secondary grid control loops but drive them in a supervisory manner and so are somewhat closely coupled to the controls, in a cascading manner. In this way the Market-Directed Control structure provides inputs that affect the basic primary and secondary control settings, but the absence of a direct feedback loop from the grid to the markets indicates that tertiary control is not yet present in this system. Day-ahead markets for generator scheduling are typical examples of market-directed control. The day-ahead and intra-day scheduling function creates a nominal trajectory plan for the generation and storage assets. Absent any variations in the forecasted load curves, this is the schedule of set points for the bulk energy system assets to follow. Secondary and tertiary controls (to be described next) exist to account in real time for actual deviations from the forecasted plan. As such, they are mechanisms for dealing with residuals.

7.3 Integrated Real Time (RT) Market-Control

Figure 5 shows an integrated market-control structure connected to the basic grid model. This structure uses markets as part of the optimization step in a receding horizon scheduling process to make incremental adjustments in grid operations. **This is for all intents and purposes model-predictive control, using the market mechanism as the optimization step**. The Market Directed Control of Figure 4 is not shown here so that the connection of the integrated market-control to the basic electric system of Figure 3 can be clearly seen.

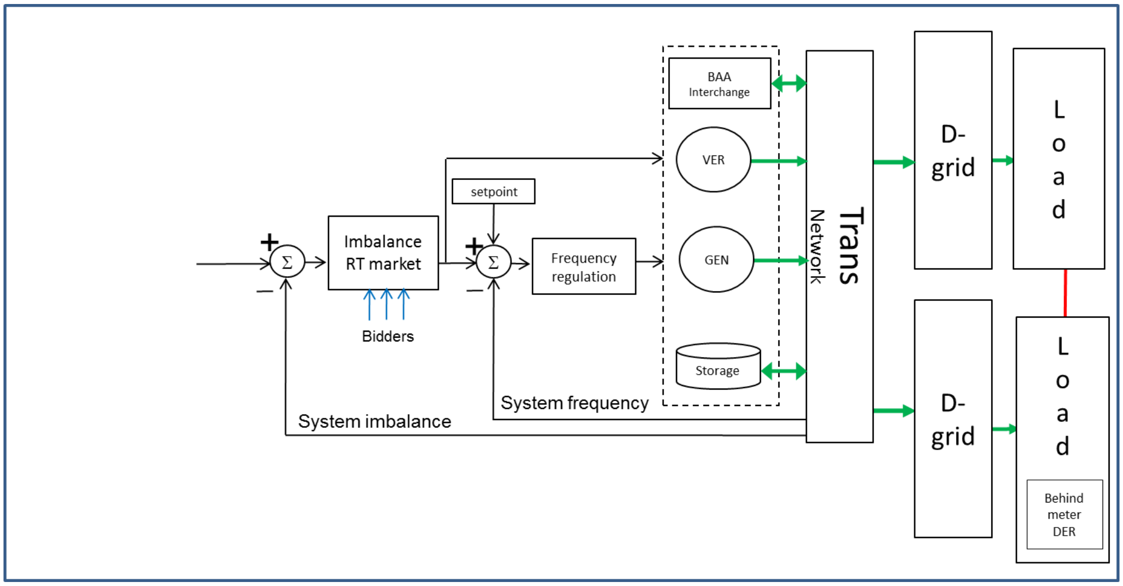

Figure 5. Integrated Real Time Market-Controls

In this structure, the markets are actually inside one or two feedback control loops and operate on a real time basis, thus providing what is sometimes referred to as tertiary control. The feedback control loops are closed around regions as large as BAAs. In the bulk system, this structure is used for incremental adjustment of balance and interchange, with markets operating on five and fifteen minute cycles. Imbalance and interchange signals may be issued directly from their respective markets (and incremental adjustments are made by the load frequency control loop on a faster cycle than the markets operate) or may be interpolated into ramps that are superimposed on the load frequency control signal. Also, in some cases, ISOs operate interchange markets where interchange bids are entered by neighboring BAAs.

7.4 Combined Market Directed and Integrated Real Time Market-Control Loops

Figure 6 shows how market-directed and integrated real time markets and controls may be combined into a single operational system. The market-directed portion provides schedules as inputs to the integrated real time market-control structure. The real time market-control loop uses the schedules as a series of set points and then makes adjustments to deal with incremental variations caused by events at the grid level.

In this combined structure the generator primary, secondary, and tertiary controls are evident as nested loops, exactly as they were in Figure 4. In addition the market-directed control structure supplies the supervisory input to the feedback control system. Note that the fastest loops and processes are the innermost; loop update rates decrease moving outward in the loop structures; the supervisory process (market-directed control) is the slowest of the set.

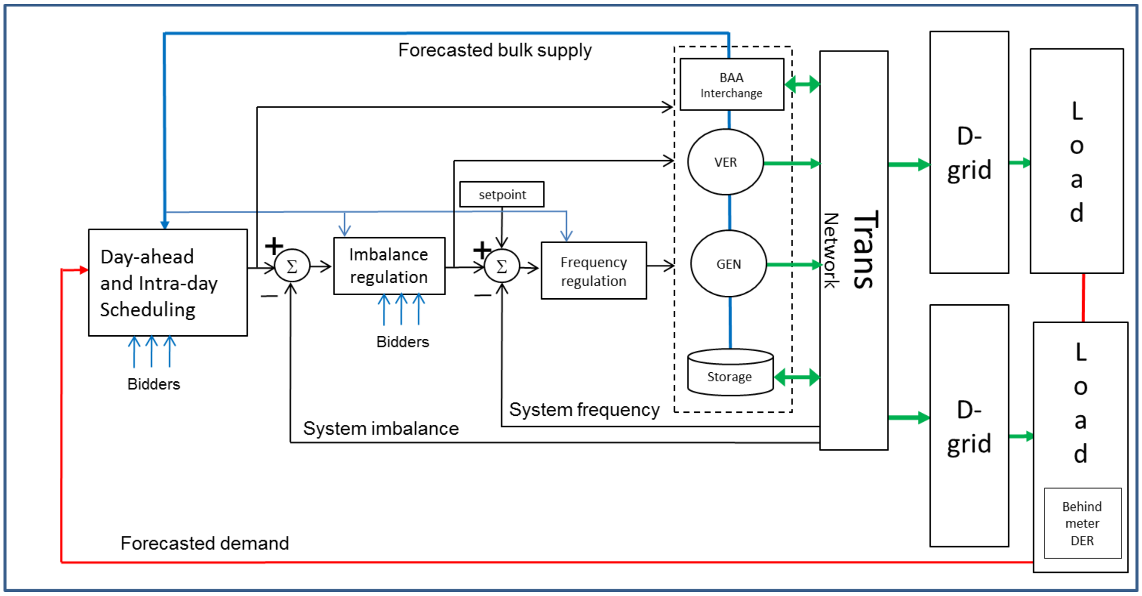

Figure 6. Combined Market-Directed and Real Time Integrated Market-Control Loops

The combined structure of Figure 6 is the essential arrangement used in ISOs and RTOs to control bulk power systems.[1] Not shown are a variety of details related to ancillary services, unit commitment, settlements, etc. In addition, details such as state estimation, contingency analysis, and other important functions are not depicted, but are implicitly assumed as necessary elements of or inputs to the feedback loops as well and the real-time and supervisory markets. The model of Figure 6 illustrates how the basic structures are combined. Some variations exist, but the essential structure is common to all. No such market-control structure presently exists at the distribution level, but some are being contemplated. At the bulk system level the introduction of market products and dispatch mechanisms has been done in some places so that DERs could be included in grid operations.

7.5 Market Authorized Control

Figure 7 shows the structure for market-authorized control, applied to the basic model of Figure 3. This structure uses a market to determine which assets will be available to a grid control system for later use. Once informed, the control system uses the authorized assets as necessary for grid operations for a period of time. These assets may also be authorized to bid into other markets.

[1] In fact, the structure of Figure 5 could also apply to the vertically integrated utility context if markets are replaced by the utility's forward scheduling and real-time dispatch procedures, which typically utilize resources' production costs rather than bid prices but perform essentially the same functional roles.

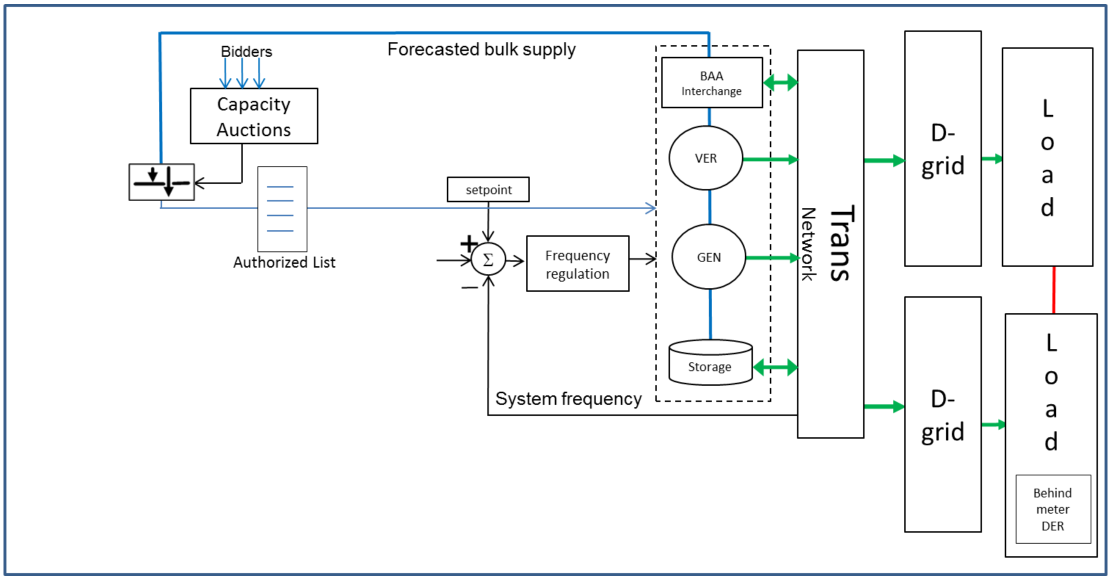

Figure 7. Market Authorized Control

In this structure, the market is completely outside of the control loops. The market update rate may be quite slow, as long as several years. ISO/RTO generation capacity auctions (as in the eastern ISOs and RTOs) and bilateral resource adequacy procurement (as in California) are examples of this structure, though it is typically combined with the Figure 5 structure as described next. At the bulk system level, such markets are linked to the market-directed and real time market-control systems to form a complete operational system, as shown next. Note that the capacity auctions determine the set of bidders required to participate in certain markets; the planning processes that inform the capacity auctions are not shown in this diagram.

7.6 Extended Model

Figure 8 shows the combination of all of these structures into a more detailed depiction of an integrated market-control system. This model has been extended to extrapolate how this may look when distribution-level grid management incorporates DER and DER market-control mechanisms. As discussed earlier, each market operates on a different time scale, with the inner nested feedback loops operating at faster update rates (shorter time cycles) than the outer ones.

This model also illustrates the need for a new kind of bulk system/distribution interface, with new requirements for information interchange and new roles and responsibilities.

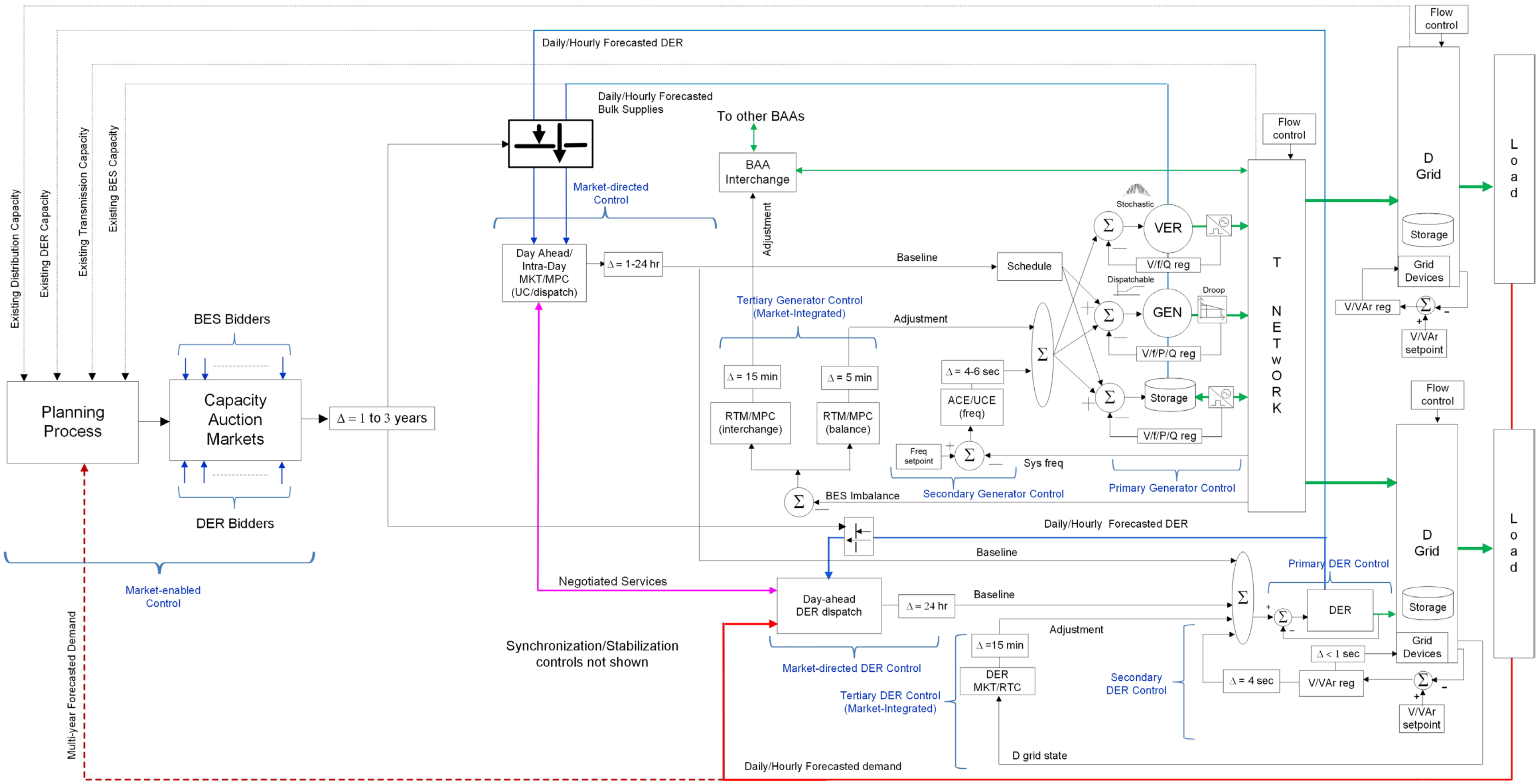

Figure 8. Extended Market-Control Model

8.0 Essential Differences Between Bulk Electric Systems and Distribution Systems

Existing electric system bulk markets and grid controls have evolved in the context of transmission networks which are quite different from distribution systems. Some of these differences are significant when it comes to establishing distribution level markets for DERs. For example, transmission networks are partially meshed and are topologically stable, well documented and have extensive state information available including synchronous phasor measurement down to as granular as 1/120 of a second. Distribution systems, radial or secondary mesh, generally do not have stable topologies due to routine maintenance and emergency operational switching. As such, distribution grid topology is time varying on both short and long time scales and in many cases is not fully or accurately documented. The system inertia that is used in the bulk system to aid stabilization of frequency, voltage, and power flows by and large does not exist at the distribution substation and feeder level as the distribution system's objective is solely delivery of energy. Additionally, very little is known about individual feeder line segment behavior and interconnected loads in real-time because it wasn't necessary for delivery of energy under the traditional paradigm.

The bulk power system is designed to transport power across parallel and interconnected systems and as such congestion management is a factor that has potentially large financial value. Congestion management on the transmission system involves determining the current state of the system in real-time and re-dispatching generation and load levels so as to establish a system state without electrical constraint violations. Congestion re-dispatch for a particular zone of the system reflects an economic value that is communicated as the locational marginal price for a specific time period in organized markets, such as those PJM and CA ISO operate.

Distribution systems do not presently have large amounts of energy producing resources that are being dispatched across the distribution grid and therefore constraint management of the type used at transmission is not directly applicable. Instead, constraint management on distribution relates to the capacity of the substation or feeder to deliver energy (in any direction) within its thermal, voltage and protection limits. This relates the capacity of a feeder to integrate DER ("hosting capacity"). Some schemes are proposed to employ various DER-based grid services to manage distribution power flows to stay within these limits, reduce line losses, and potentially increase the amount of hosting capacity for other DER.

Additionally, voltage and reactive power management on the transmission system is mainly done via primary generation control, with additional capability in some cases from synchronous condensers, and some capacitor control. Distribution Volt/VAr management essentially involves managing voltage regulator devices at the distribution substations and in some cases along the feeders, combined with line capacitor control. As the penetration of solar PV increases, the use of controllable inverters will add new capability for distribution feeder voltage and constraint management.

9.0 Implications for DER Integration

The design of markets and controls for high-DER distribution systems involves a great many factors, but the relationships involving markets and controls are new issues that have not previously been a part of distribution engineering. To design the market products and rules and the control systems properly, an understanding of the regions of applicability described above is necessary. To accomplish this, it is necessary to understand the strengths and limitations of market and control mechanisms, and to view them as complementary rather than mutually exclusive. To that end, the future grid management system should be viewed as a market-control system, not as siloed markets and controls.

The principles derived from Figure 1 and Figure 2 apply to both centralized and distributed markets and controls. Different implementations can shift the region of support boundaries but for any particular implementation one must understand the boundary locations to be able to determine the capacity of the system to handle growth in the number of control endpoints or market participants. The consequence of attempting to add endpoints or participants beyond the bound at any update rate is either:

1. Reduction of update rate, or
2. Need to re-engineer the market or control system

Re-engineering the market or control system may involve changing algorithms, upgrading communications and computation capacity, or changing to an entirely new implementation type (e.g. moving to a distributed system or a cloud-based implementation instead of a centralized private one).

One of the approaches to DER integration is the use of Transactive Energy methods. It should be clear that bulk energy systems which use market-control systems are already transactive in nature. Creating a highly distributed market-control platform for distributions systems to facilitate DER integration faces the same issues that have been dealt with at the bulk system level. In addition, there are issues of regulatory jurisdiction for some types of proposed transactive behavior (e.g. peer-to-peer energy transactions) as well as questions of how to maintain alignment with the physical system (the distribution grid) and definition of roles and responsibilities in a suitable manner given the heterogeneous nature of the DER asset mix and ownership models.

10.0 Final Comments

In regions where system operators provide wholesale electricity markets, the markets and grid controls are integrated to form converged market-control platforms. An understanding of the component elements of these platforms is crucial to the evolution of the modernized grid, since integration of third party-owned DER into grid operations presents a level of complexity that supersedes the capabilities of either markets of controls alone. The development of Transactive Energy approaches or chain code based methods or other innovations in the management of grid resources will benefit from an understanding of these concepts and building blocks illustrated in the decomposition of the market-control structure presented in this paper, as well as an understanding of the reasons why these structures were developed.

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