

AMERICA'S POWER PLAN

POWER MARKETS:

Aligning Power Markets to Deliver Value

Mike Hogan *The Regulatory Assistance Project*

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EXECUTIVE SUMMARY

Wholesale markets come in many shapes and sizes but all can be adapted to enable an affordable, reliable transition to a power system with a large share of renewable energy. The paper describes a range of market design measures available to policymakers. It starts by describing how markets can better value energy efficiency and goes on to address those opportunities where market design can more effectively serve consumers' needs as the energy resource portfolio continues to evolve. The overarching goal of these recommendations is to make markets more efficient at valuing the role that resource- and system-flexibility can play to minimize the cost of delivering reliability at all timescales.

Energy efficiency plays a crucial role in reducing the cost of the transition. While cost-effective efficiency faces well-documented market barriers, markets could better capture the value of efficiency as a resource. The ideas presented here can facilitate the value of efficiency in meeting resource adequacy and reducing the need for transmission investment.

Renewable supply has low marginal costs and many renewables have limited dispatchability. It is often said that this will challenge the traditional structure and operation of wholesale energy markets as the share of these resources grows. Fortunately regulators and market operators have a wide range of cost-effective options to smooth the transition. Making markets larger and faster can greatly mitigate the challenge of integrating variable

supply – by consolidating balancing areas, improving the quality of information available to participants about weather and its impacts, and decreasing the intervals between resource commitment and dispatch decisions. Some markets have already demonstrated net benefits from the added *system flexibility* these measures provide. Markets can also become more efficient in recognizing the value of *resource flexibility* and expanding the opportunities for customer loads to respond to market conditions. Measures include sharpening the pricing of operating reserves to more efficiently reflect short-term mismatches between supply and demand, allowing responsive loads to participate in energy and ancillary services markets, and developing new services as warranted to meet the needs of the system.

Resource flexibility is to a great extent determined at the point of initial investment. This ultimately means investing in more flexible resources and shrinking investment in less flexible resources. As the share of renewables grows, the need for adequate resources and the need for a flexible resource portfolio are two sides of the same investment coin. Market administrators should begin by developing tools to gauge the extent to which these issues will emerge within coming investment cycles, including better forecasts of net demand and changes in the demand for critical system services. Where forward markets are adopted to address expected investment needs, mechanisms should include

comparable demand-side resources and incorporate consideration of not just the quantity but also the relevant capabilities of resource investments. New market-based mechanisms should be developed to gauge the value of investment in various forms of energy storage, including end-use energy storage. Finally, The combination of the scale of needed investment and the scope for innovation in areas like demand response makes it more important than ever to encourage new market entry, for instance by third-party load aggregators.

Markets can be harnessed to save consumers and businesses money as the system modernizes. Good market design can help deliver the system and resource attributes that are needed on both operational and planning horizons, at the lowest cost.

INTRODUCTION

The *Renewable Electricity Future Study (RE Futures)* finds that it is feasible to produce 80 percent of America's power from renewables in 2050. This paper begins by summarizing those aspects of the study's findings that have implications for the structure and regulation of wholesale power markets. The paper then lays out an array of measures market authorities can take to enable markets and market institutions to deliver gains in energy efficiency, higher shares of renewable electricity and the system services required to support a modern electricity mix, all while continuing to deliver reliable and affordable electric service.¹ United States power market environments vary considerably, from local, vertically integrated, regulated or publicly owned monopoly utilities to integrated competitive markets stretching across vast regions of the country. Each model has advantages and disadvantages and each can be adapted in a number of ways to readily accommodate a growing share of renewable energy production. Many of the recommendations presented here are already being implemented in competitive market areas, facilitated by the transparency, flexibility and open access that are vital components of well-functioning markets. Some vertically integrated market areas (e.g., Colorado) have illustrated how many of these recommendations can be adapted to fit the unique circumstances presented by more traditionally structured markets.² The paper speaks to both types of market environments.

Many of the ideas in this paper build on experience in today's wholesale markets and others are being piloted in market environments across the U.S. Taken together, the recommendations represent a choice available to policymakers: between a wholesale market structure that is inherently in conflict with a high share of renewables and one that can usher in a high-renewables future.

GETTING MARKET STRUCTURE RIGHT: KEY TO A RENEWABLE ENERGY FUTURE

The National Renewable Energy Laboratory's (NREL) RE Futures Study found that an 80 percent renewable electricity system could meet load in every hour in 2050 across each of 134 grid-balancing areas across the U.S. In NREL's 80 percent scenario, nearly half of overall electricity production would come from variable renewable sources such as solar and wind power. This section highlights those aspects of the findings that are most directly influenced by the design and functioning of wholesale markets. The transition to a much more renewable — and variable — supply portfolio represents a paradigm shift for the sector, one that calls for a transformation of the architecture and operation of the power system and adaptations to wholesale markets. This future can be realized via a combination of administrative mechanisms (e.g., standards and regulations) and market mechanisms. Administrative measures will be essential to setting the U.S. grid on the pathways described in RE Futures. In both competitive and regulated monopoly market areas, however, markets can be aligned with the demands of a more variable supply portfolio to accelerate the transition and minimize the costs. *RE Futures* describes a number of critical success factors that can be facilitated by changes to markets and market institutions.

Increase efficiency

The most cost-effective *RE Futures* scenarios are premised on significant improvements in the efficient use of energy.³ There are at least two key reasons why efficiency plays such an important role: (i) much of the potential for efficiency gains is available at lower cost than supply-side measures, and (ii) a higher level of projected consumption would mean that a higher percentage of renewable supply would come from variable sources because of limits to the sustainable resource base for more dispatchable options such as biomass. Policies and programs will be the primary driver⁴ – markets, and in particular wholesale markets, can play only a limited role in driving the scale of investment in cost-effective efficiency assumed in *RE Futures* – but we will look briefly at how wholesale market practices can help.

Reduce market area fragmentation

While *RE Futures* emphasizes that there are multiple pathways to a high renewable energy future, it clearly demonstrates the benefits of balancing supply and demand over wider regions. Consistent with similar studies, it finds that the benefits of integrating markets over broader areas easily outweigh the costs. The benefits of operating markets over larger geographic footprints include:⁵

- Better access to higher quality — but more distant — sources of renewable energy.
- Less aggregate variability in both supply and demand.
- Lower integration costs due to better use of transmission and sharing of reserves.
- Risk mitigation from both resource and market diversification.

Transmission modernization and expansion can help realize these benefits. Transmission and distribution are each addressed specifically in other papers in this series.⁶

Improve operational flexibility

Because the high renewables future relies on such a large share of variable supply it significantly increases the value of certain modes of system flexibility. System flexibility can reduce the need for backup capacity and transmission expansion and reduce the need to curtail renewable production during periods of low demand and high renewable supply. These attributes of a flexible system can produce substantial benefits for the system as a whole in the form of net cost reductions and improved reliability. We will look at a number of changes system operators can make to market rules and operational practices to increase system flexibility at operational timescales.

Invest in greater resource flexibility

One of the crucial aspects of *RE Futures* was its in-depth analysis of the feasibility of meeting load in every hour in high-renewables futures. The findings illustrate the value of addressing not only traditional resource *adequacy* as an investment challenge, but also the emerging need to address resource flexibility as an investment challenge. Ensuring that resource flexibility is properly valued at the point of investment will reduce the overall amount of investment needed to ensure reliability in a system with a large share of renewable production. The value of, and therefore the investment case for, a conventional generator will increasingly rely as much (if not more so) on its ability to provide balancing services as on its ability to provide energy or even capacity.⁷ We will examine a number of market measures that can drive investment in a sufficiently flexible resource portfolio at least cost.

Make way for continued deployment of renewables

The greatest leverage for success comes from sustained improvement in the cost and performance of a portfolio of commercially available renewable technologies.

This can only come from a steady pace of commercial deployment. Where markets are already fully supplied, and in particular where investments in efficiency keep demand growth to a minimum, many existing thermal generators will come under increasing financial pressure as more renewable generation enters the system. The market challenge is to ensure that it is indeed the least valuable generators that are the ones to retire. As noted above, resource flexibility will become more valuable as the share of renewable production grows. Markets can do their part by ensuring that more flexible plants are fully compensated for their value to the system while properly discounting the value of less flexible plants. In other words, measures for shaping *investment* will be equally valuable in shaping *disinvestment* during this transitional period.⁸

RECOMMENDATIONS FOR MARKET DESIGN ADAPTATIONS

The preceding section identified those dimensions of the *RE Futures* findings that intersect in significant ways with key aspects of wholesale market structure and operations. This section will examine a wide range of cost-effective measures available to market authorities to ensure that wholesale power markets – competitive as well as regulated markets – can continue to deliver reliable, affordable power as the share of renewable production on the system grows. These adaptive measures are organized into three categories:

- Recognize the value of energy efficiency.
- Upgrade grid operations to unlock flexibility in the short-term.
- Upgrade investment incentives to unlock flexibility in the long-term.

Recognize the value of energy efficiency

A well-designed electricity market should drive cost-effective energy efficiency measures. While experience shows that markets alone cannot be relied upon in practice, there are several ways to improve the effectiveness of wholesale markets in driving cost-effective energy efficiency investments. Wholesale markets can drive efficient outcomes by properly rewarding more efficient production and system operations and by factoring transmission losses into delivered prices through, for example, locational marginal pricing.⁹ Beyond these opportunities, however, there are several ways that regulators and market operators

can improve the role of wholesale markets in promoting efficiency:

- Allow energy efficiency to participate in capacity markets.
- Set standard capacity values for a menu of standard efficiency measures.
- Consider location-specific efficiency measures as an alternative to transmission.

In competitive wholesale markets the value of capacity resources is (or should be) embedded in the wholesale clearing price of electricity. In some competitive markets however, certain regions have introduced separate capacity markets to address concerns about whether and to what extent this occurs in practice. In these markets, investments in efficiency measures can represent a comparable alternative to firm production capacity.¹⁰ Market operators should therefore **enable efficiency to participate in markets for capacity** on a comparable basis with firm supply. Whenever a new capacity mechanism is adopted market operators should establish procedures to qualify efficiency measures — they have proven capable of being at least as reliable as supply-side alternatives and are often much cheaper. For example, ISO-New England enables energy efficiency providers to bid into forward capacity markets alongside generation resources. As a result, efficiency constitutes ten percent of all new resources cleared in ISO-New England's forward capacity market since it was first opened in 2008.¹¹

Efficiency as a capacity resource is obviously different from supply resources in important respects, and the challenge of establishing comparability is a barrier to its participation in many market areas. One way to lower the barrier is to seek stakeholder agreement across multiple market areas on **standardized measurement and verification procedures and a schedule of deemed firm capacity values for a menu of common efficiency measures**.¹² This would simplify the process for qualifying efficiency as a resource and would provide more transparency and consistency for investors, particularly third-party aggregators working across market boundaries. If introduced gradually with an iterative review process, the savings in administrative burden and the increase in cost-effective efficiency investments should more than compensate for any residual deviations from standard values.

Energy efficiency investments in specific locations can also compete as an **alternative to transmission**. In both vertically integrated and competitive wholesale markets transmission investment remains largely a regulated monopoly cost-of-service business, and long-term system planning continues to be a critical part of market governance and a driver of market outcomes even in competitive market areas. The particulars of encouraging competition in the transmission sector are covered in another paper in this series,¹³ but it is important to consider transmission as *just one option* to ensure system reliability. Regulators and market operators should therefore ensure that system planning processes actively consider strategic energy efficiency measures as a possible alternative to transmission at the early planning stage.¹⁴ While Federal Energy Regulatory Commission

(FERC) Order 1000 requires that non-wires alternatives — such as efficiency — be considered, no existing entities are obligated to explore or propose them. Furthermore, traditional cost-allocation arrangements have artificially disadvantaged energy efficiency. For balancing areas that span multiple jurisdictions, transmission costs are often allocated across the whole region while efficiency costs are allocated to just one state or locality. This methodology for allocating costs may mean the market chooses a more expensive transmission option over a cheaper efficiency option. Closing these gaps will increase the likelihood that viable strategically targeted efficiency alternatives are actively explored and will increase the likelihood the market selects the most cost effective option.¹⁵

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs, FERC	Create rules, metrics, and standards for allowing efficiency to compete in capacity markets.
FERC, ISOs/RTOs, PUCs	Ensure consistent cost allocation and cost recovery methodologies for comparable demand-side and transmission investments.
FERC, PUCs, siting authorities	Strengthen the obligation to explore non-transmission solutions—such as energy efficiency—that may be more cost effective.

Update grid operations to unlock flexibility in the short term¹⁶

The shift to a high renewables future will have profound consequences for the rest of system resources.

Renewable resources will have near-zero marginal costs, and much of the renewable supply will have limited dispatchability. Thankfully, regulators and market operators have a wide range of cost-effective options to smooth the transition:

- Upgrade scheduling, dispatch and weather forecasting.
- Consolidate balancing areas.
- Promote more dispatchability of variable renewable production.
- Co-optimize energy and reserves to improve the effectiveness of scarcity pricing.
- Expand the role of demand response.
- Open day-ahead markets for existing ancillary services and begin to qualify new ancillary services.¹⁷

Grid operations should be modernized by **upgrading scheduling, dispatch, and weather forecasting**. These measures will allow the grid to respond more efficiently to the operational characteristics of variable renewables. Several recent studies have shown the benefits of scheduling over shorter intervals and improving the use of weather forecasting in grid operations.¹⁸ As the U.S. moves toward the type of resource mix described in *RE Futures*, weather will increasingly influence the power supply, specifically the availability of wind and solar

power. Using high-quality weather forecasting to update commitment, dispatch and transmission schedules more often (e.g., every 2-6 hours) can dramatically reduce the need for operating reserves.

Historical utility practice is to schedule the system at one-hour intervals and many power systems continue to do so. Sub-hourly dispatch and transmission scheduling refers to when market operators clear the markets at intervals of less than an hour — in some markets as often as every five minutes. This kind of scheduling upgrade can reduce costs of day-to-day system operations in markets with high shares of variable production.¹⁹ For example, GE found that sub-hourly dispatch could halve the system’s reliance on fast-ramping natural gas.²⁰ Moving to sub-hourly scheduling – ideally every 15 minutes or less – has consistently been shown to produce net system benefits in lower overall cost and improved reliability particularly in systems with a high share of variable production.²¹ Most of the remaining opportunities to adopt this practice are in regulated monopoly market areas.

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs, utilities	Integrate high-quality weather forecasting into supply and demand forecasts every [2-6] hours, and adjust commitment and dispatch schedules accordingly.
ISOs/RTOs, utilities, PUCs	Transition to sub-hourly dispatch and transmission scheduling. Where needed, specify automatic generation control in new power purchase agreements.

Several recent studies have identified the benefits of balancing supply and demand over a broader geographic region, also known as **consolidating balancing areas**. Benefits include: better use of existing transmission infrastructure, less supply variability, less demand volatility, real-time access to more operating and contingency reserves, less need for backup generation capacity, more use of renewables, and more liquidity and less price volatility in the market due to more competition.²² These benefits increase in value as more of the supply mix becomes variable. Most competitive markets are already in the process of consolidating

control areas under one balancing authority or have done so, though some disconnects remain between ISO regions. In regions where actual consolidation of control areas is not anticipated, there are a number of alternatives available that may offer some of the benefits of actual consolidation: an organized exchange for grid services *between* balancing authorities (an “energy imbalance market”)²³ and dynamic transfers between balancing authorities.²⁴ Dynamic line rating for transmission lines between balancing areas²⁵ can also increase transparency and reduce congestion.

DECISION-MAKER	RECOMMENDATION
FERC, NERC	Update the criteria for approving the creation of new balancing authorities, especially cases of balancing authority consolidation or expansion. ²⁶
ISOs/RTOs, utilities, PUCs, FERC	Open an exchange for grid services across multiple balancing authorities (an “energy imbalance market”).
PUCs, NERC, utilities	Enable dynamic transfers between balancing authorities.
FERC, NERC	Approve dynamic line rating for transmission line owners.
PUCs, state legislatures	Approve consolidation of balance areas.

Promoting more dispatchability in variable renewables has proven beneficial in several systems where variable renewables are a significant share of production. In Xcel Energy’s service territories in Colorado and Minnesota, for instance, 60 percent of wind generation has the option of providing regulating reserves and has, in some instances, provided all of the

frequency regulation required by the system. Exposing the demand for various grid services to competitive procurement from all qualified sources will allow renewable generators to gauge the value of investing in and offering these services, avoiding the tendency to invest in more back-up capacity than would actually be required.

DECISION-MAKER	RECOMMENDATION
PUCs, ISOs/RTOs, FERC	Expose the value of automatic generation control services; make sure market rules enable renewables to provide them.

Improving the effectiveness of scarcity pricing

can have a number of beneficial impacts on security of supply, market power mitigation and activation of incremental levels of price-responsive demand. Its immediate benefit here is to more effectively value resource flexibility. The primary measures to accomplish this are more granular locational pricing of supply and

the co-optimization of energy and operating reserves. The objective is to fully reflect the reliability cost in real time of using reserves to provide energy during periods of tight supply. As variable supply increases this will direct more revenue to those resources able to swing easily between providing energy and acting as reserves and less revenue to less flexible resources.

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs, FERC	Adopt operating reserve demand curves.
ISOs/RTOs, FERC	Co-optimize reserves with energy in real-time markets.
ISOs/RTOs, FERC	Allow demand response to participate in price formation.

Expanding the role of demand response is another important way to move to the kind of flexible system described in *RE Futures*. For a century the power system has been structured around the assumption that supply had to follow uncontrollable demand in every instant. The incremental cost of allowing demand free rein was

largely hidden in flat rates and uneven cost allocation across customer classes. These historical practices have presented a challenge for wholesale markets since such markets were first conceived, and as supply becomes less controllable there is greater urgency to revisit them.

Fortunately, as the value of controlling electricity consumption rises, the cost to do so is dropping as the range of options expands. Today demand response refers to far more than just emergency demand reductions. It also means using more electricity when there is a surplus (e.g. storing useful energy by heating water or charging electric vehicles) and using less when there is scarcity (e.g. drawing down energy stored earlier for transport or heating). These responses can be dispatched remotely with no noticeable inconvenience to the consumer, which means their availability to system operators is effectively unlimited. This development has important implications for modern grid management and cost minimization.

As with generation resources, some up-front investment is required to access the demand response potential, and new interventions may be required to overcome market barriers.²⁷ Some wholesale market operators (e.g., PJM) have already begun to tap the potential of demand response, including the kinds of response options described above.²⁸

Demand response can participate in wholesale markets in three ways: as capacity, as energy, and as an ancillary service. First, in markets where forward capacity mechanisms have been deployed, demand response that meets the necessary qualifications should be allowed to compete on an equal footing with supply, as discussed above for efficiency. Several markets have seen tremendous benefits from doing so. For instance, PJM meets approximately 10 percent of its total resource adequacy needs from demand response at significantly less than the cost for comparable new supply resources.²⁹

Second, market operators can allow demand response to bid into day-ahead and intra-day energy markets in the same way that generators bid into those markets. This allows demand to participate in setting the true market value of electricity in daily scheduling intervals, most likely via third-party aggregators or retail providers.

The third way that demand response can participate is via markets for ancillary services, such as regulation and spinning reserves. Market operators should enable demand response to participate as a balancing service on an equal footing with supply-side resources. Some wholesale market operators have already experienced success with this. For example, PJM has successfully enabled demand response to bid into its ancillary service markets to provide regulation services,³⁰ while ERCOT gets half of its spinning reserves from demand response.³¹ The Western Electricity Coordinating Council (WECC), on the other hand, prohibits the provision of spinning reserves by demand response resources.

Where demand response has been successful, third-party aggregators have played a crucial role in innovating new services, attracting new investment, and delivering value to consumers. Some market areas, particularly many regulated monopoly market areas, continue to prohibit or discourage participation by third-party aggregators. As variable renewable production increases, this restricted access (which very likely already has a measurable cost to consumers) will lead to artificially inflated costs of integration. All market areas can and should encourage active participation by third-party aggregators.

Realizing the potential of demand response in each of these roles will require setting standards for determining its cost-effectiveness in relevant timeframes.

DECISION-MAKER	RECOMMENDATION
PUCs, ISOs/RTOs, FERC, NERC	Allow demand response to participate in capacity, energy, and ancillary service markets on equal footing with supply-side resources.
PUCs	Allow third-party aggregators full access to markets.
PUCs, FERC, ISOs/RTOs	Remove tariff barriers to cost-effective demand response (e.g., restrictive demand charges).

All market areas in the U.S. are a mix of central dispatch and bilateral arrangements. Some areas are dominated by bilateral contracts between power producers and utilities, meaning generation is dispatched via contractual obligations rather than via bids submitted to an independent market operator. In these situations, generator owners and their customers choose when to dispatch supply, but grid operators are ultimately responsible for maintaining the balance between supply and demand. In principle there is no reason this arrangement cannot work well, yet there is evidence that current market structures can fail to provide adequate incentives for resources to supply the ancillary services required to keep the grid in balance.³² This market failure — combined with the fact that some market operators rely on cost-based procurement rather than

open markets for certain ancillary services — has driven a decline in the availability of some important services over the past twenty years in the U.S. As renewables become a larger share of the mix, the failure to value these important services properly may lead to an artificial lack of flexibility. Regulators can address this issue in the near-term by **adding day-ahead markets** for ancillary services to value the needed flexibility. For example, the Electricity Reliability Council of Texas (ERCOT) runs a day-ahead market for a range of ancillary services, which has supported the state’s success in wind integration. Regions that already use markets for some services should extend them as needed to encompass additional services. Moreover, **market operators should expand ancillary services markets as appropriate to include new services** such as multi-interval ramping.³³

DECISION-MAKER	RECOMMENDATION
PUCs, ISOs/RTOs	Institute day-ahead markets for ancillary services where they don’t currently exist.
FERC	Expand Order 888 to include additional ancillary services such as load following, frequency response, inertial response, and voltage control.
PUCs, FERC, ISOs/RTOs, NERC	Assess the need for new services that may arise as renewable production grows (e.g., multi-interval ramping service).

Update investment incentives to ensure flexibility in the long run

Competitive wholesale energy markets should be capable of signaling the need for investment in new capacity resources, as well as the value of different levels of operational flexibility available from different types of resources. The question of whether such investment signals are sufficient in practice is the subject of much debate, and in some markets administrative measures such as forward capacity mechanisms have been introduced. This paper does not take a position on whether interventions to value investment in firm resources are necessary or desirable. However, the operational flexibility available from system resources is to a very great extent determined at the point of initial investment. As we transition to a high renewables future, the reality is that the need for adequate resources and the need for a sufficiently flexible resource portfolio are two sides of the same investment coin. Regulators and system operators can address this new reality in a number of ways:

- Develop tools to better forecast net demand and the value of various forms of flexibility.
- In regulated markets, survey existing generators' flexibility and, when it becomes valuable to do so, invest in low cost options to increase the flexibility of existing generation.
- Adapt forward investment mechanisms to capture the value of certain resource capabilities.

- Adopt forward markets for specific system services.
- Create forward markets for a time shifting service.
- Encourage new market entrants wherever possible and consistent with overall market structure.

The first step in ensuring adequate long-term investment in system flexibility is **developing tools to forecast net demand and the value of resource flexibility**. Net demand refers to total customer demand minus total generation from variable, zero-marginal-cost resources.³⁴ Net demand forecasts provide a basis on which to project demand for flexibility services in the future and estimate the price one would be willing to pay for them. Making transparent the value of investments in resource flexibility is essential to establishing a business case for such investment. Several ISOs have recently deployed (or are actively considering) operating reserve demand curves as one way of doing so, and such market mechanisms provide a basis for projecting the value of investment in resource flexibility.

In regulated markets, improved knowledge about expected increases in demand for resource flexibility provides the basis to **survey existing generators' flexibility, determine how to make best use of it and to gauge the value of investing in low-cost options to increase the flexibility of existing generation**. In Colorado, for instance, the state's largest utility has employed these methods that, along with improved forecasting, have helped them cut their wind integration costs by more than half.³⁵

Long-term, or “forward”, capacity markets operate in several parts of the U.S. (e.g., PJM holds annual auctions for capacity three years in advance of the year the capacity is to be delivered)³⁶. These long-term markets are designed to place a future value on firm resources based on the forecasted demand for such resources. Resources that clear in the auction receive a commitment to be paid that value for some period of time (e.g., in PJM the commitment is for one year of payments, while in ISO New England the commitment can be for up to five years). System operators can **adapt capacity mechanisms to capture the value of system service capabilities**. There are several ways to accomplish this,³⁷ but the end result should be that more flexible resources are cleared first in whatever quantity is available at or below their projected value to the system. Less flexible resources would then clear only to the extent that additional resources are needed, and they would also clear only at or below a price reflecting their lower value to the system.

As an alternative, or where forward capacity mechanisms are not used, system operators can **adopt forward markets for specific system services**. These markets would project the future demand for specific critical services and enter into forward commitments specifically for those services. There are several examples of forward system service markets.³⁸ In those markets with both capacity mechanisms and ancillary service markets, however, providers of ancillary services do not yet receive commitments as far forward as do providers of capacity. It will be increasingly important to ensure that investment signals for resource flexibility are at least as compelling as investment signals for the resources themselves. Mechanisms such as operating reserve demand curves gauge the supply of cost-effective flexibility services and, when necessary, the information needed to procure those services forward.

Large-scale energy storage is often cited as a critical requirement for systems with high shares of renewables, but it is more useful to think in terms of the system service that storage technologies provide. *RE Futures* results indicate that demand response will deliver sufficient flexibility through the earlier stages of renewables penetration, while the value of shifting the production of electricity from one time period to another (referred to here as “time shifting”) will grow as the share of renewables on the system reaches very high levels.³⁹ Some large-scale energy storage technologies that have historically been uneconomic may well become profitable, while other approaches to time shifting may prove to be more competitive. The challenge will come in making the emerging value of investments in providers of time shifting services more transparent to potential investors, something that was difficult even when the value of such a service was relatively stable. **Creating forward markets for a time shifting service can help make this happen, not only because they can reveal the value of the service** but also because the range of technology options is expanding to include not only traditional grid-scale storage technologies (primarily pumped storage hydro) and new grid-scale storage technologies like compressed air, but also numerous distributed options such as dispatchable demand response, end-use thermal energy storage and electric vehicle batteries. Some of these options will become economic long before others, and as time shifting services become more valuable the use of market mechanisms can help select the most economic options for providing them, or determine that no cost-effective options are available.⁴⁰

One way to create a time shifting service would be to mimic the success of instruments known as financial transmission rights. These are options traded actively in many wholesale markets that allow widely separated buyers and sellers engaging in energy transactions to hedge forward the risk of congestion arising from time to time on the intervening transmission facilities. Using this as a model, system operators could initiate a market in “financial time-shift rights” by which a seller could hedge the risk of producing in one time interval and selling

at a set price to a customer in a different time interval. In the same way that financial transmission rights markets reveal the value of incremental investment in transmission in a given area, a financial time-shift rights market could reveal the value of incremental investments in time shifting capabilities. The initial demand may be low and the market may clear with only existing options, such as the ability to postpone demand for a given energy service. As the share of variable resources grows, however, the demand for time shifting will grow as well.

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs, PUCs	Develop tools for forecasting net demand and establishing the value of critical services.
FERC, ISOs/RTOs, PUCs, utilities	Adapt capacity markets to capture the value of resource flexibility, or adopt forward markets in specific system services, or both; pilot market mechanisms that would help provide the business case, if any, for investment in either grid-scale or distributed sources of time shifting services.

The scale and capital intensity of the transition envisioned by *RE Futures* presents an enormous opportunity for investors. The investment required to transform the electricity system exceeds the balance sheet capacity of incumbent generators.⁴¹ Given the limited set of alternatives the most promising option is to open the door wide to new entrants. **Encouraging new entrants wherever possible** becomes a critical factor in expanding the pool of available capital and reducing costs. In regulated monopoly market areas the scope for this is obviously more limited, however there are opportunities compatible with the existing governance structure. Actual or virtual consolidation of control areas

can increase liquidity by widening the pool of available buyers and sellers, a critical step in attracting new entrants. Another valuable step is to fully enable third-party aggregators of demand-side resources to bring capital and innovation to the market.⁴² Particularly in competitive market areas, however, there is no substitute for aggressive regulatory oversight and enforcement of the competitive landscape. Concentration of market power in itself is a major barrier to new entry, and concern about abuse of market power in some markets has driven regulators to impose price caps and other measures that create additional barriers to new entry.⁴³

DECISION-MAKER	RECOMMENDATION
PUCs, state legislatures	Enable third party aggregators to bid into all markets.
FERC, PUCs	Closely monitor and aggressively enforce competition in the market.

CONCLUSION

Wholesale power markets can be a powerful force in achieving the transition envisioned by *RE Futures*. Regulators and market operators have a wide range of options available to them to make this happen, both in competitive market areas as well as in regulated monopoly market areas. In most cases policymakers can look to experience with similar measures elsewhere, and in other cases markets can experiment at small scale with innovative approaches. Taken together, these measures will align the operation of wholesale power markets with the goal of a reliable, affordable, renewable energy future.

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ENDNOTES

- 1 Many of these points can also be found in Volume 4 of *RE Futures*.
- 2 For a more detailed treatment, see Schwartz et al, 2012. States preferring to retain direct control over their electricity markets assume a number of obligations in doing so. Seizing opportunities such as those identified here and in the WGA report is one of those obligations, and forums such as the Western Interstate Energy Board and the Southern States Energy Board provide existing platforms through which these measures can be implemented.
- 3 *RE Futures* also analyzed a high demand scenario, finding that 80 percent renewables could still meet load in every hour.
- 4 An extensive body of literature focuses on the market barriers and failures affecting the actual rate of investment in cost-effective efficiency measures and the range of administrative programs available to address them. See Prindle et al, 2006, and Joshi, 2012.
- 5 Mills and Wiser, 2010.
- 6 See two of America's Power Plan reports: one by Jimison and White and another by Wiedman and Beach.
- 7 As *RE Futures* states on page xxxviii, "...a high renewable future would reduce the energy-providing role of the conventional fleet and increase its reserve-providing role."
- 8 Particularly in regulated monopoly market areas it will be important to address legitimate claims for compensation where stranded investments were made in good faith in reliance upon prior explicit assurances. Also see America's Power Plan report by Foley, Varadarajan and Caperton.
- 9 Locational marginal pricing refers to factoring transmission congestion in to resource values, based on whether they are providing a service on a specific part of the system that would have otherwise been over- or under-supplied.
- 10 See, for example, page vi of Pfeifenberger et al, 2011.
- 11 Experience with energy efficiency participation in wholesale capacity mechanisms can provide lessons for market design criteria. Specifics about qualifying criteria and procedures for measurement, reporting, and verification are beyond the scope of this paper, but see PJM Capacity Market Operations (2013) for many of these details, and Pfeifenberger et al, 2011, for an assessment of the results.
- 12 See Todd et al, 2012; Schiller et al, 2011; Jayaweera and Haeri, 2013.
- 13 See America's Power Plan report by Jimison and White.
- 14 Cowart, 2012.
- 15 Watson and Colburn, 2013.
- 16 For an extended analysis of the potential benefits available by adopting these and other measures, see GE Energy, 2010.
- 17 "Ancillary services" refers to services the grid operator uses to manage through the intervals in daily schedules for supply and demand or to restore the supply/demand balance when the unexpected happens.
- 18 See Lew et al, 2011, GE Energy, 2010.
- 19 See North American Electric Reliability Corporation, 2011.
- 20 GE Energy, 2010.
- 21 A notable exception at this writing is Spain, where stakeholders in a system with high penetration of variable renewables have concluded that a move to sub-hourly balancing is not yet warranted. It will be useful to better understand what is different about circumstances in the Spanish system.
- 22 See North American Electric Reliability Corporation, 2011, Milligan et al, 2010.
- 23 PacifiCorp and the California Independent System Operator, 2013.
- 24 "Dynamic transfers" refer to virtual transfers of control for specific resources over certain times.
- 25 See America's Power Plan report by Jimison and White for an explanation of dynamic line rating.
- 26 Boucher et al, 2013
- 27 Cappers et al, 2013.
- 28 PJM, 2011.
- 29 PJM, 2012.
- 30 PJM, 2013.
- 31 See North American Electric Reliability Corporation, 2011, pg 50 and 61; also Milligan and Kirby, 2010.
- 32 Martinez et al, 2010.
- 33 Ela et al, 2012.
- 34 Other less controllable sources, such as many industrial cogeneration facilities, are also netted out.
- 35 See Xcel Energy, 2012, for the thirty-minute reserve guidelines and Xcel Energy and EnerNex Corporation, 2011, for the integration costs.
- 36 PJM Capacity Market Operations, 2013.
- 37 One approach — "apportioned forward capacity mechanisms," wherein the capacity market is divided into tranches to meet required grid capabilities in the future — is described in Hogan and Gottstein, 2012. Another approach is to assign points to resources offered based on identified operating capabilities with the price to be paid determined by the score received. ISO New England has proposed adapting their existing forward capacity market so that it will elicit an investment response when the potential combined supply of energy and operating reserves cannot meet demand. See Coutu, 2012.
- 38 For example, ISO New England purchases operating reserves one year forward; National Grid in the U.K. has conducted annual auctions for short-term operating reserves for as far forward as fifteen years.
- 39 Figure ES-7 in *RE Futures* shows the role of storage per se becoming significant once penetration exceeds 30-40 percent; other studies suggest the threshold for cost-effectiveness of grid-level storage options could be much higher.
- 40 The environmental impact of energy storage technologies varies considerably, and must be properly considered as part of the traditional state review process.
- 41 See, for example, European Climate Foundation, 2011.
- 42 See America's Power Plan report by Foley, Varadarajan and Caperton for more detail on how to reduce financing barriers.
- 43 See two of America's Power Plan reports: one by Harvey and Aggarwal and another by Lehr.

APPENDIX 1: ACRONYMS

ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
PUC	State Public Utilities Commission
RE Futures	Renewable Electricity Futures study
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council
WGA	Western Governors Association