Revenue Sufficiency and Reliability in a Zero Marginal Cost Future

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Revenue Sufficiency and Reliability in a Zero Marginal Cost Future

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Abstract—**Features of existing wholesale electricity markets—such as demand side complexities, administrative pricing rules, and policy-based reliability standards—can distort market incentives from allowing generators sufficient opportunities to recover both fixed and variable costs. Moreover, these challenges can be amplified by other factors, including (1) low- or near-zero marginal cost generation, particularly arising from low natural gas fuel prices and variable generation (VG), such as wind and solar, and (2) the variability and uncertainty of this VG. As power systems begin to incorporate higher shares of VG, many questions arise about the suitability of the existing marginal-cost-based price formation, primarily within an energy-only market structure, to ensure the economic viability of resources that might be needed to provide system reliability. This article discusses these questions and provides a summary of completed and ongoing modelling-based work at the National Renewable Energy Laboratory to better understand the impacts of evolving power systems on reliability and revenue sufficiency.**

Keywords-component; revenue sufficiency, reliability, resource adequacy, capacity adequacy, LOLP, LOLE, missing money, production cost modelling, ERCOT

I. Introduction to Revenue Sufficiency and Resource Adequacy

In many parts of the world, wholesale electricity markets exist to schedule and dispatch generating units, given demand and the transmission network configuration, at minimum cost to the system. In the early 1990's several countries moved to deregulate electricity markets in an effort to address excessive planning reserve margins and to increase the efficiency of unit commitment and system dispatch [1]. An added benefit of these markets, generally referred to as Regional Transmission Organizations (RTOs) in the United States, is that they, at least in theory, create a more competitive market by increasing transparency and co-optimizing operations to minimize the system-wide operational cost. During the past several years, many of these markets have been influenced by the adoption of variable generation (VG), such as wind and solar, which has variable and uncertain power output and a near-zero marginal cost due to the lack of fuel costs.

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Although there are differences in many of the details in wholesale electricity market design, a common premise is that a large number of competitive generators can deliver electricity supply, while regulatory measures can be enacted to eliminate or, at the very least, limit the exercise of market power and the associated distortions of competitive prices. [1] Under this premise, marginal cost pricing results in a cost-effective dispatch such that resources are compensated for their operational costs.[2] Generators rely on times when the market clearing price rises above their marginal cost, such as during scarcity pricing events, to provide additional revenue to cover fixed costs. However, such long-term, fixed cost recovery is not guaranteed under the marginal cost pricing premise, and it is the focus of this paper.

Revenues are sufficient when payments for individual services that are required to maintain a reliable grid—including energy, capacity, and flexibility—cover the fixed and variable costs of providing those services. Revenue insufficiency (often called the "missing money" problem) results when those payments are not adequate to (1) cover both fixed and variable costs incurred by existing generators (a necessary condition to remain in the market) and/or (2) justify investments in new capacity that is needed for reliability. Electricity markets are well-known to exhibit significant characteristics that prevent them from functioning as a purely competitive market. Revenue sufficiency challenges are rooted in these factors, among which include the so-called "demand-side flaws," namely inelastic demand arising from a lack of price signal clarity and the ability and/or desire of consumers to respond to such price signals [3]. With few exceptions, consumers are not aware of, nor could they respond to, changes in wholesale prices; therefore, the effective elasticity of demand for electricity is very low. As a result, price does not effectively ration usage, potentially resulting in times with insufficient

[1] Throughout this paper, we refer to "prices" as the price of market products at the bulk power system level.

[2] For a given dispatch or market period, the resource is compensated for variable costs. However, additional out-of-market payments may also apply; these include uplift (or make-whole) payments to cover no-load or start-up costs and day-ahead profit guarantees to prevent generators from losing profits earned in the day-ahead market when those generators would lose money by performing actions that benefit the system in the real-time market. Possible causes for these out-of-market payments include misalignment of average and marginal cost curves and discrepancies between day-ahead and real-time operational conditions (e.g., [2]).

supply to meet demand and the inability of the market to determine the market-clearing prices needed to attract an efficient level and mix of generation capacity [3]. These demand side flaws lead to the need for policy-based reliability requirements and administrative pricing rules, which can give rise to revenue sufficiency challenges. Additional causes for revenue insufficiency include missing or inadequate compensation for all grid services (also known as the "missing markets" problem) and uncertainty over future economic and policy factors, which can, for example, result in an overbuilt system.

Resource adequacy occurs if the level of installed capacity is sufficient to ensure a very small probability, size, and duration of blackouts caused by insufficient installed generating capacity. Methods based on loss of load probability (LOLP) and related reliability metrics are often used, as is the common loss of load expectation (LOLE) of 1 day/10 year.[3] The chosen reliability[4] target is set by policy and is generally the result of an administrative action that establishes an acceptable level of reliability for long-term supply. The target could be set to higher reliability levels (lower blackout levels), such as 1 day/30 years, or lower reliability levels (higher blackout levels), such as 1 day/3 years. Whatever the target may be, it is fundamentally divorced from the market process and outcomes, unless there is a reliability component in electricity pricing [3], [4]. Because energy-only markets cannot explicitly take into account whether the target is 1 day/10 years, 1 day/2 years, or 1 day/20 years, there is no reason to expect that the market will simultaneously deliver the target long-term reliability, balance supply and demand, and provide sufficient revenue to all resources so that all costs (fixed and variable) are recovered.[5] This means that energy-only markets by themselves are not guaranteed to achieve an administered reliability target.

The effect of higher reliability is that additional capacity must be built, but this capacity may never need to run; thus, it will have little, if any, impact on the market prices during the year. During periods of shortage, prices can spike significantly, but administratively-set price caps may interfere. The result is that resources that may be needed for only a short time of the year (such as this extra capacity) must recover both capital and operational costs in a small number of hours or days, and therefore they may not have the opportunity to earn sufficient revenue to remain in the market [5]. Further, energy-only markets do not have any information about installed capacity levels or LOLE targets. Therefore, the revenue paid out in the energy market will be unrelated to the planning reserve, and thus it cannot guarantee revenue sufficiency.

The revenue insufficiency challenge identified above results from fundamental market complexities and inefficiencies. However, this challenge can be amplified by other factors, such as low natural gas prices, low demand,[6] and increased proliferation of VG resources through impacts on bulk electricity prices [4], [6]. This last impact is discussed in greater detail throughout the remainder of this section.

In the United States, wind is generally bid as a price-taker because it has a near-zero marginal cost. In some markets, wind can bid a curtailment/dispatch-down price, which is often the negative of the production tax credit; otherwise, this bid would likely be zero. In either case, the introduction of VG into the generation mix has two primary impacts: (1) price reduction, and (2) energy sales reduction for other generators. First, prices will be reduced in the market period because the zero-cost VG will displace one or more resources at the top of the dispatch stack. When VG is the marginal resource, price can be zero (or slightly negative). This means that, on average, electricity prices will be reduced as VG is introduced into the market. As the penetration of VG increases, the average price will decrease further. Power system economic studies and actual practice have shown such price suppression impacts during periods of, or areas with, high VG output [7], [8], [9], [10], [11], [12], [13], [14], [15], [16]. Second, the remaining resources that are dispatched after the lower-cost wind is called upon will run at lower capacity factors.

Both of these VG impacts can be illustrated by the merit-order effect, which pushes more expensive resources up (or off) the dispatch stack. This is shown graphically in Fig. 1. The top panel of the graph shows a simplified supply curve for a small power system. Three demand curves (D1, D2, and D3) represent three different levels of electricity demand throughout the year; their intersections with the supply curve reveal hypothetical prices at 350 MW, 650 MW, and 900 MW.[7] Prices are determined by the generation cost of the marginal unit; for the three demand curves, the price is $30/MWh, $50/MWh, and $80/MWh, respectively.

Now suppose that some combination of VG resources is added to the system. In this case, the original supply curve shifts right by the amount of renewable energy in any given hour. For this example, assume 500 MW of renewable output is added; the new supply curve is illustrated in the bottom panel of Fig. 1. Now the price at any demand level less than 500 MW is $0/MWh. Reproducing the demand curves shown in the top panel reveals equilibrium prices of $0/MWh, $30/MWh, and $35/MWh, respectively. For higher levels of VG, the region of the supply curve with the $0/MW(h) price is larger, showing that (1) there will be more hours of zero prices at higher levels of renewables, and (2) prices in other hours will be lower than in the absence of additional VG, all else equal. Reductions in average price will make it more difficult for generators to recover all their costs because they will run less often and receive a lower average price when they do run.

These VG merit-order effects may amplify revenue sufficiency challenges for some generators (e.g., peakers)

[3] LOLP is calculated by a suitable convolution algorithm or Monte Carlo analysis using generator capacity and forced outage data along with load data; the typical application reports the probability of insufficient supply on an hourly or daily basis. LOLE is the expected value of insufficient supply, which is based on the LOLP probabilities and is typically reported in days per year.

[4] This is separate and distinct from the common N-1 reliability standard. The reliability focus of this paper is on resource (or capacity) adequacy.

[5] A market with excess supply will likely have less total revenues since excess capacity will likely be distributed across the merit-order curve or to the left of the intersection of the demand curve. This will enable the system to operate at a lower portion of the merit-order curve, effectively suppressing prices.

[6] Multiple market areas in the United States, including ERCOT and MISO, have experienced suppressed energy prices that were driven by low demand and natural gas prices [17], [18].

[7] For simplicity, the time period represented by each demand curve is 1 hour.

that are needed to ensure resource adequacy but do not earn sufficient revenue to remain in the market [5], [19], [20]. Although this discussion shows why VG may reduce the revenue earned by all infra-marginal generators[8] in a market setting, it does not directly address revenue sufficiency in the absence of renewables. It also does not evaluate the potential revenue shortfall earned solely by selling into energy markets or evaluate potential solutions. The latter two points will be briefly discussed in Sections III and IV.

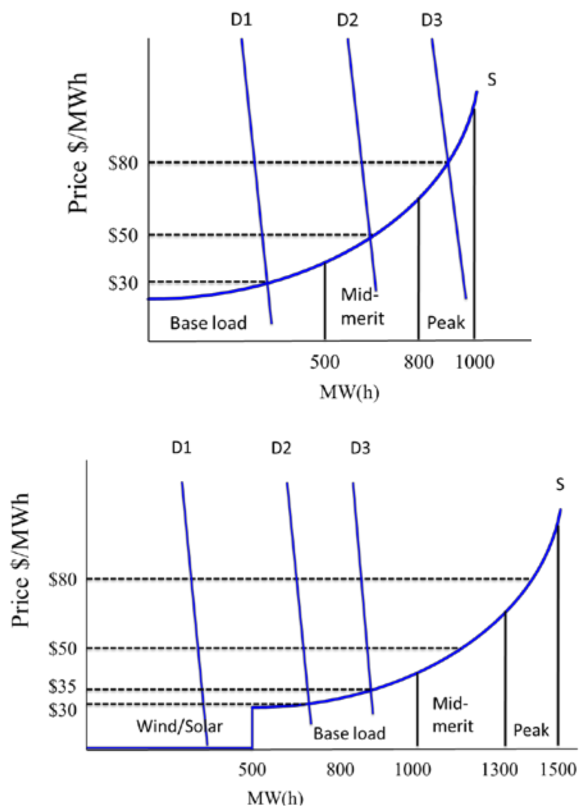

Figure 1. Impact of variable renewable generation on market prices.

A final key impact of VG is that it increases the variability and uncertainty in the system, which can in turn require increased flexibility [21]. Although certain changes to short-term energy and ancillary service markets may be needed to ensure that the available flexibility is offered to the market, this may not guarantee that sufficient flexibility is built or available in the first place. This could necessitate new methods for evaluating and compensating all needed aspects of capacity adequacy.

II. Evaluating the Existence and Depth of Revenue Shortfalls

Evaluating potential new market designs can be done with electricity production cost models (PCMs). These models simulate bulk power system operations based on techno-economic constraints of generation, demand, and transmission for a predefined system. These models attempt to represent key market fundamentals (e.g., unit commitment, the representation of ancillary service products, pricing rules, outages, congestion, and marginal-cost-based dispatch and pricing) so that comparisons among alternative designs and system configurations can be made.

One of the most critical aspects for evaluating market mechanisms to ensure revenue sufficiency is proper pricing. In real markets, these "right prices" mean that appropriate economic signals are provided in both the planning and operation time frames to stimulate the needed capacity and grid services to achieve reliability [22]. In a modelling framework, it means that simulations produce accurate prices, which in turn allows for the meaningful evaluation of relevant outputs, notably dispatch, production costs, revenues, and net revenues.[9]

In most PCM modelling frameworks, resources are assumed to offer their marginal generation capability at marginal costs. Although this assumption is reasonable for feasibility studies and long-term planning, it does not adequately consider the market behaviors that impact prices in real electricity markets. Representing these behaviors can have a significant impact on the accuracy of the price outputs—and thus revenues—from the model. Recent work at the National Renewable Energy Laboratory (NREL) has found discrepancies between market prices calculated by these marginal-cost-based PCM simulations when compared to actual prices [23]; these discrepancies are driven in part by the lack of strategic market participant behaviors in default PCMs. Market prices can be simulated by assuming specific types of strategic market behavior, such as through agent-based models that make assumptions about how market actors will respond in different situations or imperfect competition models that allow suppliers to adjust their prices and/or outputs to maximize profits given their belief about the behavior of other suppliers [24]. Another option is to apply exogenous or endogenous bid markups to capture assumed bid behaviors of generators [23].

Another consideration in evaluating revenue sufficiency is the resource adequacy level of the system. For example, a power system that has a large excess of generating capacity cannot be expected to generate sufficient revenue through the energy market so that all plants—including excess plants—can remain profitable.[10] The objective of revenue sufficiency is to ensure that resources that are needed to achieve the reliability objective have sufficient opportunity to earn enough revenue to cover all of their costs. Under these conditions, if there exists an oversupply of generation, then one would expect that some resources would go out of business until the reliability target for resource adequacy is met. Fig. 2 shows the overall price decline in Germany's wholesale markets when there was a substantial increase in VG. The concern raised by this graph, and by recent experience, is that cost recovery is a challenge for many plants in the German system. In 2014, Germany had peak load of 84 GW with 192 GW of installed capacity, of which at least 72 GW was from VG resources [25]. It is therefore not possible to separate the influence of oversupply with renewable energy on this price decline [26].

Solutions to the revenue sufficiency problem generally fall into a few categories: (1) capacity market or capacity payments, (2) supplementing the energy-only market with a reserve product and scarcity pricing, and (3) power purchase

[8] Generators that have a short-run marginal cost below the market-clearing price.

[9] Net revenues are revenues minus variable costs.

[10] A strong correlation between low net revenues and surplus capacity has been observed for ERCOT in recent years [17].

agreements or other contracting approaches. These options are a means to compensate generators who provide services needed by the grid that are not explicitly incentivized [27]. In the United States, the Electric Reliability Council of Texas (ERCOT) has developed an operating reserve demand curve (ORDC), which creates a continuous function of energy price adders based on the operating reserve level in the current hour. When reserves are short, the price is high. The reserve-level calculation is based on an operational LOLP and value of lost load (VOLL), and the intent of the ORDC is to restore revenue to resources that can provide reserves during the time of highest need. Despite concern about the effectiveness of this product, general consensus has found the ORDC to function as intended and designed, though some improvements could be made [28]. Other studies have shown the ORDC to be a preferred market design option compared to fixed reserve prices or fixed capacity payments for valuing incremental reserve capacity and helping to ensure revenue sufficiency [10].

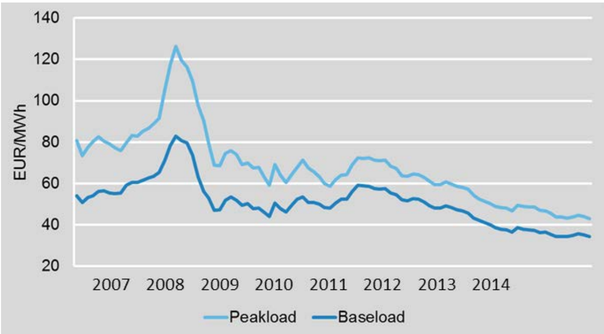

Figure 2. Decline in wholesale energy prices in Germany [26].

III. Revenue Sufficiency Analysis Using an ERCOT-Like Production Cost Model

This section summarizes results and methodology from recent work described in an NREL technical report [23]. This work is the first step in a multiphase research effort at NREL to study the impacts of wind—among other system components—on the electric power system as it is operated today and in the transition to a modern, clean, flexible power system. A key focus is to evaluate possible market designs that enable proper cost recovery and system reliability.

Reference [23] explored the impact of strategic bidding behavior, ancillary services, and changing fleet compositions on net revenues using a PCM that represented a simplified version of the ERCOT system (Fig. 3) for the years 2012–2014; we highlight results here for 2013. The study used PLEXOS[11] to solve for the least-cost system-wide day-ahead dispatch of the system with an hourly resolution using historic wind data for each wind power plant and load data by load zone (North, South, West, and Houston). The model contained 318 generators and was run zonally for the four ERCOT load zones, thereby ignoring intra-zonal transmission constraints and any corresponding local congestion.

In practice, ERCOT is an energy-only market and does not rely on capacity markets or payments to encourage new generation technology.[12] Although many revenue sources could be considered, this study included only energy and four types of operating reserves: regulation up, regulation down, spinning, and non-spinning, all of which exist in the actual ERCOT market. An additional flexibility reserve, "Flex Up,"[13] was included in select sensitivity scenarios to capture the additional variability and uncertainty burden from wind resources [29]. This flexibility reserve requirement varies by hour, based on the load and wind values, and only the reserve requirements resulting from an over-prediction of wind production (i.e., flexible reserve in the "up" direction) were included. Key model outputs were total system production cost, regional energy prices, generation capacity and dispatch by category, generator net revenues, and hours of operation. Revenues from both energy and ancillary service markets were included.

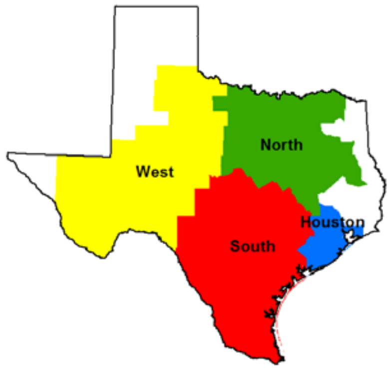

Figure 3. ERCOT-like PCM study area by load zone [30].

To capture behavior impacts and produce more accurate price outputs, the study calibrated the model using a limited set of market participant strategic bidding behaviors by means of different sets of markups. These markups served as a proxy for actual strategic bidding by small generators that occurs in the ERCOT system; such flexibility in their energy-bidding behavior is permitted by the so-called "Small Fish Rule."[14] These markups were applied to the true production costs of all gas generators, which are the most prominent generators in ERCOT and are typically the marginal resource. Three different markup percentages were applied as fixed multipliers to the first third, middle third, and last third of the marginal cost-based offer curve for each natural gas generator. In some cases, the markups were identical throughout the offer curve (a "flat" markup); in other cases, they increased toward the higher levels of the offer curve (a "graduated" markup). The markups refer to the set of percentage increases in the offers. For example, a 0-40-80 markup would include no markup on the first third

[11] PLEXOS is a mixed-integer programming tool that can perform a variety of optimization-based functions and simulations of energy markets. It is one of several commercially available PCMs. A list of publications that describe previous analyses performed with this tool is available at http://energyexemplar.com/publications/.

[12] Other energy-only markets include the Alberta Electric System Operator and Australia's National Electricity Market.

[13] The Flex Up product in this study held back or brought online additional eligible generating capacity to meet an hourly reserve requirement for the expected forecast error (uncertainty). Because the model was day-ahead only, the study did not model the real-time usage of these reserves.

[14] The Small Fish Rule is defined by a provision of the Public Utility Commission of Texas Substantive Rules that deems any electricity generating entity controlling less than 5% of the total installed generation capacity in ERCOT as not having ERCOT-wide market power. The rule protects small new entrants in the generation market from claims of market power abuse, providing the opportunity for a sufficient return on investment and removing potential uncertainty that might otherwise discourage the entry of new generation [32].

of the offer curve, a 40% markup on the middle, and an 80% markup on the highest third of the offer curve. True production cost offer curves are based on fuel costs and variable operation and maintenance costs. The study tested no markups (0-0-0), flat markups (40-40-40), 0-40-80 markups, 0-40-120 markups, and 0-40-200 markups.

The price duration curves for each markup case for 2013 were compared to the historic ERCOT day-ahead settlement point prices (SPPs)[15] [31]; the results are shown in Fig. 4. This figure, as well as percent difference metrics (see [23]), suggest that the model captures the middle hours well, but it overestimates the upper tail and underestimates the lower tail. The markup case that best matched historic prices, erring on the side of overestimating prices (and therefore underestimating any revenue sufficiency challenges), was selected as the Benchmark scenario. Results showed that markups can help generators increase their net revenues overall, although net revenues may increase or decrease depending on the technology and the year under study. While not shown here, the study also compared ancillary service capacity prices against historic values from ERCOT. The model tended to underestimate Non-Spinning and Spinning reserve prices and overestimate Regulation Down prices. Regulation Up prices more closely matched across all years. However, reserves contribute a small fraction of the total system revenue and thus have only a small impact on the revenue sufficiency calculation.

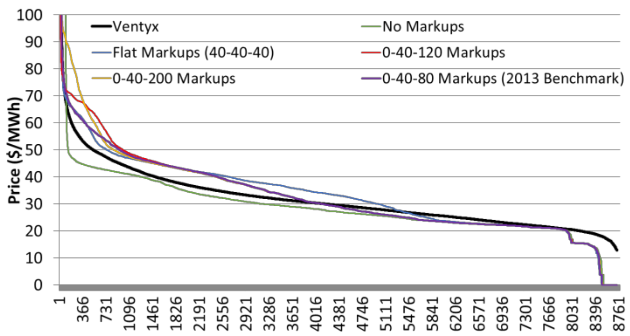

Figure 4. Day-ahead price duration curves averaged across all regions (magnified to show prices at or below $100/MWh) for all 2013 markup scenarios and historic day-ahead SPPs from ERCOT [23].

To evaluate the impact of increasing penetrations of wind, the addition of a new reserve product, and changing fleet composition on revenue sufficiency challenges, a set of four sensitivity scenarios were then run based on the chosen Benchmark scenario. Table I summarizes these sensitivity scenarios. Net revenues were compared to the annualized investment costs for new generators from the 2015 NREL Annual Technology Baseline (ATB) data set [33] to estimate revenue sufficiency, shown in Fig. 5 for 2013. The dots represent the current annualized investment costs for new generator units,[16] and the bars are the annual net revenues from existing generators in the model simulations (normalized by installed capacity, i.e., $/kW-yr). These net revenues represent the available portion of total revenues that are available to cover fixed costs. When these dots are larger than the achieved net revenues, then revenues are not sufficient to signal investment in new generation capacity; the current system capacity is adequate. This could also reflect revenue sufficiency challenges for existing generators, depending on their sunk costs. If revenues are not sufficient to invest in new units when more capacity is in fact needed to reliably meet load, then this can lead to resource adequacy issues. However, when capacity is scarce, then prices will rise, incentivizing additional investment.

TABLE I. SENSITIVITY SCENARIOS EVALUATED FROM THE BENCHMARCK CASE [23]

Sensitivity Scenario	Wind Capacity	Flexible Reserve	Coal Retirement
High Wind	High Wind[a]	Benchmark	Benchmark
Flex Up	Benchmark	Flex Up reserve requirement	Benchmark
Flex Up High Wind	High Wind[a]	Flex Up reserve requirement	Benchmark
Retire 4 GW Coal	Benchmark	Benchmark	Retire coal[b]

a. Approx. double ERCOT-wide wind energy penetration level from Benchmark (~10% to ~20%)

b. Retired ~23% of base coal fleet (~2/3 in North one, 1/3 in South zone)

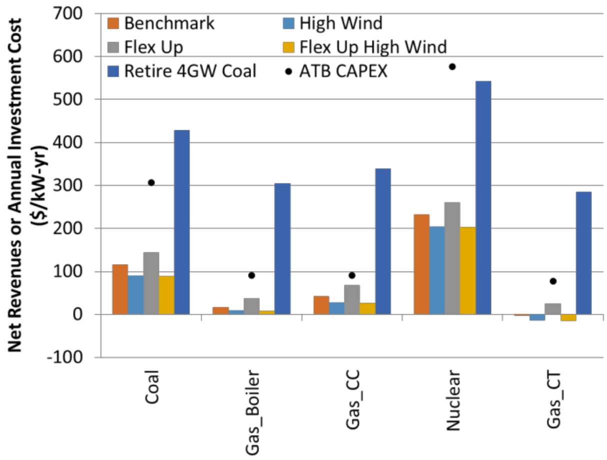

Figure 5. Net revenues for the 2013 Benchmark and sensitivity scenarios and ATB annualized investment costs [23].

As reflected by net revenue values (bars) that were lower than the corresponding annualized investment costs (dots) in Fig. 5, revenue sufficiency challenges were implied in nearly all scenarios for all generator types evaluated with the study's simplified model of an ERCOT-like system. The only exception was when large amounts of coal were retired in the Retire 4 GW Coal scenario, wherein investment in new generators was supported for all types but nuclear, which has an annualized investment cost that is slightly larger than the achieved net revenue. In this Retire 4 GW Coal scenario, the significant increase in net revenues was driven by scarcity pricing events,[17] suggesting that this scenario may have resource adequacy challenges. Scenarios with a high wind penetration saw reduced net revenues, driven by an overall depression of energy prices, including five times more zero-price hours in 2013 in the wind-rich

[15] SPPs are averages of all resource node prices within each of the four trading hubs. ERCOT's publicly-available day-ahead SPP data set used in this analysis included values already averaged from the resource nodes to the trading hub level. These prices are hourly for the day-head market. ERCOT provides an analogous data set for real-time prices.

[16] These are for new capacity and may differ substantially from the actual fixed costs of existing plants.

[17] A load penalty price curve was used as a proxy generator for demand response, which also reflects potential scarcity pricing and resource adequacy problems. Because the exact revenues heavily depend on this price curve input, results should be interpreted as qualitative only.

West zone of ERCOT. Recall that because the simulated market prices in the Benchmark scenarios were higher than historic prices, the implied revenue sufficiency challenges shown here are underestimated. Additionally, precise estimates for revenue sufficiency would require understanding the investment costs for specific projects, both for existing and new generating facilities. However, the focus of these results is on the relative revenue sufficiency outcomes between the scenarios, which show the impacts of higher wind penetrations, a new flexibility product, and reduction in thermal baseload capacity.

This study also noted an important link between ancillary service and energy revenues. As shown by the total revenue breakdown in Fig. 6, the contribution from all reserves (darker shading) constituted a very small fraction of the total revenues, approximately 4%–5% for the 2013 Benchmark and Flex Up scenarios. This small percentage is consistent with values indicated in the ERCOT *2013 State of the Market Report* [11]. The dominant share of revenues came from energy (lighter shading in Fig. 6); however, the additional reserve requirement in the Flex Up scenario increased both the reserve and energy revenue streams—by approximately 44% and 13%, respectively—relative to the Benchmark scenario in 2013 (compare orange to blue bars). This linkage reflects the interdependency of energy and reserve pricing of a real system that co-optimizes energy and reserves, such that the provision of energy and reserves is at the system-wide lowest cost. This feedback highlights the importance of ancillary service products and pricing on the overall revenue sufficiency picture.

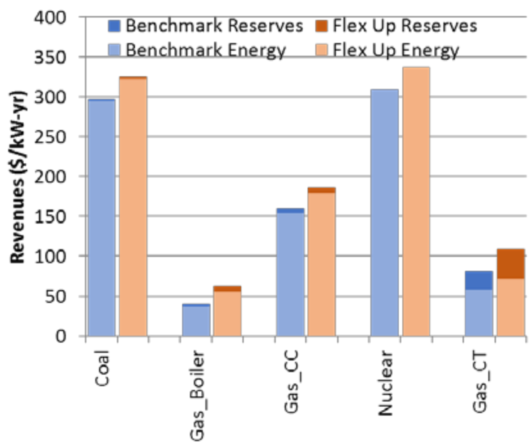

Figure 6. Total revenues for the 2013 Benchmark and Flex Up scenarios [23].

IV. Cost-Recovery Methods Using a More Detailed ERCOT Production Cost Model

As previously discussed, a key part of the "right prices" discussion involves capturing strategic bidding behavior. The completed work summarized in Section III applied static generator bid markups as a proxy for strategic bidding behavior. Other methods for capturing strategic bidding include imperfect competition models (e.g., Nash-Cournot and Bertrand) as well as agent-based models; however, these options significantly increase model run time. Another option for achieving right prices that support capacity adequacy and revenue sufficiency is to apply an energy price adder, such as an administratively set fixed price, a fixed capacity payment, a price based on a continuous function such as through ERCOT's ORDC, or a dynamic markup that captures the fixed-cost requirements.

Our preliminary modelling efforts have investigated the last of these options using the built-in long-run marginal cost (LRMC) recovery method in PLEXOS. This method applies a price premium to recover any net revenue losses, given variable- and fixed-cost inputs for each generator. For the scenarios presented here, these markups are calculated based on the portfolio of generators at each node. We use a significantly more detailed ERCOT-like PCM[18] than that used in Section III; the model here was run with a nodal representation (7,000 nodes with 723 generators); hourly day-ahead unit commitment; hourly real-time dispatch; and hourly historic wind, solar, and load data from 2014. For the LRMC scenarios, we use the model's default generator-level variable costs with generator fixed costs (capital and O&M) from the 2016 NREL ATB [34], battery fixed costs from [35], and demand-response fixed costs from the 2014 Energy Information Administration form 861 for demand response program costs in Texas [36]. The LRMC scenario results serve as an upper bound for cost-recovery needs among the generator fleet because it does not adjust for units that have fixed costs that are sunk.

Price duration curves for historic real-time ERCOT SPPs [31], a Base Case model run, and two model runs using the LRMC method for 2014 are shown in Fig. 7. The corresponding price and revenue statistics are tabulated in Table II. The two LRMC runs assume different biases for how markups are assigned to peak and off-peak periods. The Bias=5 applies higher markups during peak hours and lower markups during off-peak hours compared to the Bias=1 case.

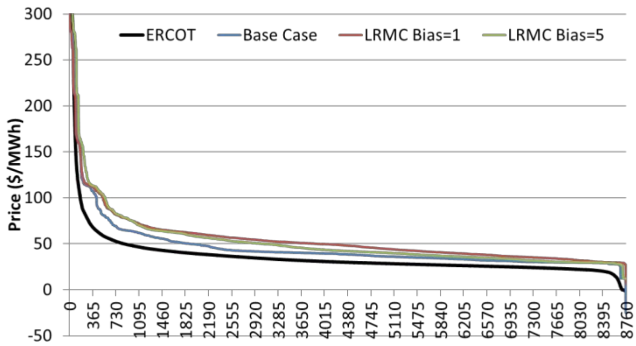

Figure 7. Real-time price duration curves averaged among all regions (magnified to show prices at or below $300/MWh) for 2014 model runs and historic real-time SPPs from ERCOT.

Fig. 7 and Table II show the overall price and revenue elevation effect from the LRMC recovery algorithm, with a 14% increase in the average energy price across the full ERCOT system with a markup Bias=1, and an 87% increase with a markup Bias=5 relative to the Base Case. The impact of the bias is especially visible in the top and bottom 10% of all hours. As shown in Fig. 8, the LRMC method increases net revenues the greatest for nuclear and natural gas peaking units (GT and IC). Further work is needed to optimally tune the bias parameter, adjust for sunk costs, and determine the optimal system configuration that achieves resource

[18] We used a PLEXOS model of ERCOT created by Energy Exemplar, with several modifications, including conversion to day-ahead, real-time, and site-specific historic wind data (same as that used in [23]).

adequacy without overbuilding the system. While these results are preliminary and should be interpreted qualitatively only, this LRMC modeling exercise points to the need for additional or modified market mechanisms to ensure revenue sufficiency, as shown by the increase in prices to ensure cost recovery with the LRMC scenarios. Future work will evaluate possible cost-recovery mechanisms and further improve the PCM data inputs and representation of the ERCOT system. Special focus will be given to model modifications to better align price outputs to historic values, such as through methods to capture strategic bidding behaviors, outages, and congestion.

TABLE II. PRICE ($/MWH) AND REVENUE ($BILL/YR) STATISTICS

	Historic ERCOT	Base Case	LRMC Bias=1	LRMC Bias=5
Average Price	38.2	48.4	55.0	90.5
Median Price	29.9	38.5	48.0	42.0
Average Top 10% of Hours	110.6	137.4	128.3	515.4
Average Bottom 10% of Hours	17.8	27.1	30.6	28.4
Average Middle 80% of Hours	31.7	29.8	33.1	30.2
# of Hours ≤ $0/MWh	231	7	0	0
Total Revenue	--	19.9	22.3	29.1
Total Net Revenues	--	9.7	12.0	19.1

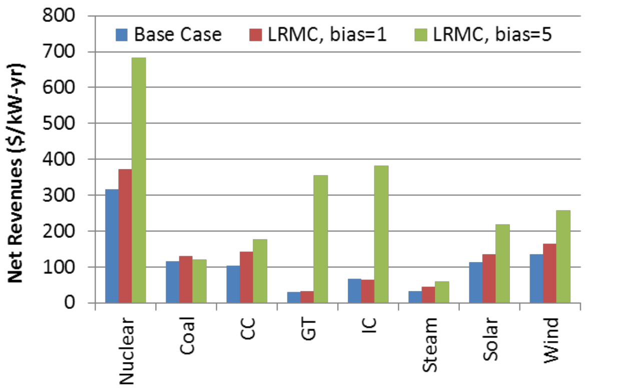

Figure 8. Net revenues by generator technology type for 2014 Base Case and LRMC model runs.

V. SUMMARY AND FUTURE WORK

This article discusses the economic principles behind the growing concern over reliability and resource adequacy of the bulk power system and provides a summary of completed and ongoing work at NREL in the United States. This effort is focused on the fundamental, bidirectional linkage of reliability and revenue sufficiency in electricity markets. Reliability standards, which are defined by policy, along with associated administered pricing rules, can prevent prices from reaching levels that properly incentivize generators to produce during times of scarcity. In the other direction, revenue insufficiency can result in premature plant retirements and/or a lack of new resources for reliability (specifically capacity and/or flexibility needs). These market complexities can result in instances when generators, particularly those on the margin, do not earn sufficient revenue to cover both fixed and variable costs. Such revenue sufficiency challenges can be further amplified by various factors, such as low- or zero-cost generation and the variability and uncertainty of VG.

NREL is using a suite of modelling tools to gain a better understanding of reliability and revenue sufficiency challenges in an evolving electric power grid. The first phase of this work examined the impact of various market structures—including market behavior, ancillary services, and changing fleet compositions—on net revenues using a PCM that represented a simplified version of the ERCOT energy-only market for the years 2012–2014. The study found that revenue sufficiency challenges are implied for this simplified ERCOT system under base conditions; these revenue sufficiency challenges are marginally abated by adding a new flexible reserve product and are amplified when the penetration of wind energy roughly doubles. However, when a significant portion of the coal fleet is retired, proxy scarcity pricing enables sufficient net revenues to justify new investment, which reveals potential resource adequacy concerns. Results also confirm that conventional, variable-cost-based production cost simulations do not capture prices accurately, and this particular feature calls for proxies for strategic behaviors and more accurate representations of how electricity markets work.

Moving forward, NREL is developing a more comprehensive modelling test bed to assess reliability and revenue sufficiency challenges under a wide range of market design options and revenue sources. This future work aims to develop an improved behavioral model for strategic bidding and a more accurate representation of electricity markets and system operations, specifically with outages and congestion. Key research questions for this effort include:

- What market designs best enable the power system to move from the current state to a future target while ensuring revenue sufficiency and reliability?
- How do market designs impact (e.g., hinder, enable, neutral) the technically feasible solution to grid integration studies?
- In an evolving power system, how reliable is reliable enough, and how should reliability be calculated?

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