Stakeholder Comments

Renewable Integration: Market & Product Review Phase 2 Day-of Markets

Submitted by	Company	Date Submitted
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SCE thanks the California Independent System Operator's (CAISO) substantial thought-work in creating the Renewable Integration Market Vision and Roadmap (RIMVR) "day-of" straw proposal. We also appreciate the opportunity to provide stakeholder comments, and for hosting a comprehensive stakeholder process.

SCE understands the intent of this proposal is twofold: to develop thinking on possible ways for redesigning markets in order to better integrate intermittent energy sources, and to solicit reactions from stakeholders that can improve the proposals or highlight complexities, omissions, or problems in the ideas. Stakeholders in this process must be external to and internal to the CAISO, including the CAISO's IT, Legal, and Operations staff. Through this process, the CAISO will be able to determine appropriate elements to its market redesign while ensuring that potential issues or complexities have been considered and are manageable. SCE supports the CAISO's plans to use this process to build a comprehensive vision and road-map for redesigning its markets.

In this document, SCE offers comments on many aspects of the RIMVR "day-of" straw proposal, including the guiding market principles, the Real Time Energy Dispatch Process (RTED) options, the newly proposed Real Time Imbalance Service (RTIS), proposed changes to Regulation service, and operational issues associated with the Day-Of markets.

1. The ISO's guiding principles should more clearly emphasize cost-causation.

SCE supports the ISO's RIMVR guiding principles but encourages the CAISO to put more emphasis on the principle of "cost allocation based on cost causation", rather than subsuming this idea within the "Transparency" principle. It's clear that the CAISO has consciously applied this principle in several instances in the RIMVR, but, by expressly ranking this cost-causation principle as a top-tier principle, the CAISO can uniformly abide by this principle throughout the entire RIMVR initiative.

2. SCE supports the decisions to eliminate HASP and to rely on two settlements but requests additional information on how imports at the interties will be treated.

SCE strongly supports a two-settlement system by eliminating HASP. The simplification of the day-of markets by having a two-settlement system over a three-settlement system will result in a cleaner optimization process, fewer uplift costs, and improved transparency.

In eliminating HASP, however, the CAISO must determine how the intertie transactions will efficiently and properly settle. SCE does not believe a pure price-taking[1] solution is workable, and encourages the CAISO to explore other options and to provide greater detail on proposals for the settlement of imports on the interties. The establishment of a workable settlement for imports will be an important element of this market redesign initiative. This issue does not, however, need to be resolved right away as it will surface regardless of whether the CAISO selects day-of RTED option A or option B.

3. SCE encourages the CAISO to use the RIMVR process as a means to shift towards an optimization approach that solves for a probabilistic solution rather than a deterministic solution.

With increasing amounts of uncertainty and system variability, due in large part to VERs, SCE believes the CAISO's market optimization could be improved by solving for a distribution of possible outcomes rather than for a point estimate. SCE believes this shift is an appropriate topic for RIMVR and for the overarching Renewables Integration Market Product Redesign (RIMPR) initiative because the shift towards a stochastic least-cost minimization process would better manage uncertainty and variability, which are key challenges of VERs. Although the resource mix is changing, the CAISO's current optimization process has not changed to address this fact. Under the current structure, the optimization will identify a cost-minimized solution based on fixed inputs and point estimates (e.g. exact load forecasts, exact forecast of generation production), though the actual market situation is likely to differ from the forecasted one, likely resulting in a higher cost outcome than predicted. A switch towards a probabilistic minimization process will likely yield more actual (rather than forecasted) least-cost solutions and avoid easily disrupted singular solutions.[2]

4. At this stage of the RIMVR, SCE prefers RTED Option A over Option B. Option A addresses known deficiencies in the current market in a simple manner and aligns with likely FERC mandates.

SCE believes Option A (15-minute real-time settlements) is likely to better address known deficiencies in the current real-time market, some of which create a reliance on administratively set prices as opposed to bid-based market signals. A 15-minute RTED, in contrast to the current 5 minute market, would better allow an efficient and economically rational real-time market where economic bids and fundamental supply/demand principles set market prices. Economic

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[1] SCE views "pure price-taking" as when a resource commits to a Real-Time delivery without the opportunity to bid, and then the resources does not know the price it will be paid until after delivery and after real-time prices are established.

[2] Nelson, Jeffrey, "California's New Electricity Market: Overview of First Year of Performance and Recommendations Moving Forward", 2010, p. 43

efficiency would also be gained by combining unit commitment decisions with real-time energy and ancillary services dispatch and pricing, ensuring all these elements are co-optimized and priced consistently. Option A seems to yield a somewhat simpler real-time market system which in turn yields greater transparency into market operation.

The 15-minute solution also resolves or provides a straight-forward means to address several market priorities. The CAISO details some of these benefits, but core to SCE is the ability to find simple and workable alternatives to HASP, to position CAISO markets to conform with expected FERC requirements[3], to provide opportunities for Real Time schedule adjustments that do not require unfeasibly fast security constrained dispatches, and to allow workable schedules and settlement windows for dynamic pricing and demand response.[4] We expect at a minimum inter-ties will move toward 30-minute scheduling, and a 15-minute market should easily support this situation.

5. The ISO should structure its real-time market to incorporate updated information prior to real-time energy dispatch.

SCE supports the ability of VERs and other resources to update their schedules closer to real-time.[5] Given the fact that VER forecasts can improve dramatically closer to real-time, this ability would benefit the market as a whole by lowering the need for imbalance, RTIS and regulation services.

Cost incentives should be used to encourage accurate forecasts. Rather than creating a "3rd settlement", incentives for providing accurate "closer to real-time" forecasts can be created by allocating integrating services costs (e.g. RTIS, and Regulation) to resources that deviate from "updated" forecasts or that inaccurately respond to market signals and CAISO dispatch instructions[6]. For example, the CAISO should consider instituting a "mandatory closer to real-time forecast update" process at a time close enough that these forecast are relatively accurate, but far enough away from actual delivery so that the CAISO has time to incorporate this new information and use the optimization to select cost-effective solutions. In conjunction with the ability to update schedules closer to real-time, these incentives will encourage highly accurate forecasting and responsiveness.

Metrics for accurate forecasts and responsiveness should be discussed and reviewed by stakeholders. One possible measure for forecasting accuracy for VERs and load would be whether an updated forecast was more accurate than the ISO-provided forecast. In this case, intermittent resources or load would benefit by providing accurate updated forecasts and should in turn reduce their allocated integrating costs.

The timelines for providing updated forecasts have a material impact and involve trade-offs. On one hand, forecasts typically become more accurate closer to real-time. On the other hand, the

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[3] FERC has proposed intra-hour scheduling for all Balancing Authority Areas in their NOPR: RM10-11-000 "Integration of Variable Energy Resources"
[4] CAISO Straw Proposal - Renewables Integration Market Vision and Roadmap Day-of Market, p. 25
[5] Other resources may include Demand Response resources.
[6] It is SCE's understanding of ERCOT methodology that if a VER's schedule is not aligned with its forecast it is subject to additional uplifts.

availability of economic resources to respond to changing conditions decreases closer to real-time as many of these units are otherwise committed or designated to be off-line. This trade-off implies that there is some point prior to real-time where the benefits of updated forecasts are outweighed by the reductions in available dispatchable resources.[7] The CAISO should continue discussion with stakeholders to determine an "optimal time" for updating forecasts.

SCE recommends the ISO incorporate these concepts into the RIMVR in pursuit of least-cost market solutions.

6. Operational and dispatch considerations for Real-Time Imbalance Service (RTIS) must be addressed.

Like the CAISO, SCE expects there to be a need for more "balancing" capabilities. The creation of explicit price signals for this capability through the introduction of the RTIS is a logical step by the CAISO. A detailed assessment of the idea, however, reveals some potential issues that must be addressed.

As currently proposed, the RTIS product may inadvertently limit the supply of resources. This outcome would harm ISO markets and operations by potentially creating excessively high costs for the RTIS product. In other words, a large pool of resources must be able to supply RTIS in order for trade liquidly and to provide sufficient balancing capabilities. RTIS capability will only be useful if sufficient resources can comply with the dispatch system.

Based on currently established practices, "1-minute" RTIS would only be able to be dispatch through AGC. This assessment is based on the SCE belief that any dispatch period shorter than 5-minutes must be done computer to computer.[8] On this timeline, any non-automated dispatch system would be ineffective and unmanageable for generators that require human-directed action. As such, with a one-minute dispatch signal, RTIS capable resources would need a computer-to-computer dispatch system, and, because AGC is the only sanctioned dispatch system available in this timeframe, a one-minute dispatch period would require that all RTIS resources be AGC enabled. This outcome will inadvertently restrict the potential pool of resources available to provide RTIS down to those that currently provide Regulation, as these are the only units with AGC.

The reliance on AGC capable resources creates a further issue too. RTIS resources would have "stranded capability" wherein that they could be moved every four seconds (per AGC) but are

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[7] Nelson and Nelson, "Integrating Variable Energy Resources while Maintaining Reliability: The Role of Integrating Services and the Importance of Proper Cost Allocation," June 2011, pp. 4-5. In addition, we have attached the full document given its relevance to the current discussions. The document follows these comments (Page 9).

[8] Based on SCE's operational experience, manual dispatch instructions given more frequently than every five minutes will be unworkable, unreliable, and thus unable to meet the performance requirements of the CAISO. Any RTIS product that is designed to, in part, be dispatched manually at less than five minute intervals will not work and should not be allowed without detailed assurance such a system could be successful. The CAISO's proposal of a one minute interval, although for discussion purposes only at this point, does not seem workable if it would attempt to rely on means other than AGC for dispatch.

instead limited to move only once per minute. This sub-optimal use of AGC resources would likely hinder the CAISO's operational flexibility and result in a less economic market product.[9]

In SCE's view, two changes could address this situation. In one option, the CAISO could develop a new dispatch system to allow for a shorter than five-minute dispatch signal specifically for RTIS resources.[10] The costs and structure for such a change would need significant analysis. As a second option, the RTIS product could be designed with a five-minute dispatch interval and could thus be signaled using the existing Automatic Dispatch System (ADS).[11] This approach would likely only coincide with a 15-minute RTED. In this case, ADS capable resources would create a large pool for RTIS participants, and AGC resources could participate in both the RTIS or Regulation markets, avoiding the "stranded capability" issue.

Of the above solutions, the idea of a five-minute RTIS product (combined with the 15-minute pricing of Option A) seems the most reasonable to SCE at this point, but this idea would need to be evaluated to ensure it provided adequate balancing capability for the CAISO. Also, shifting the RTIS periodicity to five minutes would likely necessitate an expansion of the CAISO's proposed new regulation product. Comments to this effect are detailed below.

These changes would not impact the CAISO's proposed cost-allocation structure for RTIS. SCE strongly agrees with the CAISO approach to allocate balancing costs based on a cost-causation principle. SCE provides additional comments on this matter, further in these comments.

Finally, regardless of these changes, SCE does not believe that RTIS alone should serve as a proxy for integration costs. While SCE supports the idea of a clear price index for integration costs for the reasons detailed by the CAISO, this cost must be accurate, and SCE does not believe that RTIS alone, especially if dispatched every five-minutes, represents the true costs of integration. RTIS should be a part of this cost, but the costs for regulation service should also be factored in. SCE would like to see data to support the CAISO's claim that load alone causes the need for intra-minute regulation. Additional comments on this topic are included in a "cost-allocation" section below.

7. Regulation and RTIS must be developed in concert – changes to RTIS may necessitate changes to the proposed regulation.

In order for RTIS to compliment the more granular Regulation in balancing the CAISO system, different RTIS time horizons would require different Regulation product structures. If RTIS is to have a one-minute dispatch signal, then the proposed zero net-energy (ZNE) settlement Regulation product may work. If RTIS is to have a longer time horizon, however, then ZNE Regulation may be infeasible. The two products need to be designed to work together in the most efficient and feasible manner possible.

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[9] To the extent that the current product can be redesigned to include "pay for performance" compensation, the CAISO might be able to create reasonable compensation structure for both fast and slow moving regulation resources. Note that SCE does not endorse this approach because it does not increase the pool of ramping resources likely to be needed in the future.

[10] It could also be possible to review and possibly relax the technical standards for AGC, perhaps allowing more resources to be AGC capable.

[11] Reference to SCE's views on computer to computer dispatch systems.

Changes to RTIS, such as a five minute dispatch period, would likely require the new proposed regulation to play a larger role in balancing service than as currently proposed. It's not clear to SCE that ZNE regulation products alone could suffice in this case. SCE encourages the ISO to explore this issue and consider changes to the regulation product to create a highly efficient and effective mechanism for regulation. To achieve this goal, the regulation product will need to incorporate bid and settlements structures that allow the ISO's dispatch algorithm to leverage the most economic resource in the most efficient way possible. Dispatch systems must therefore consider prices for capacity and mileage, ramping and turnaround speeds, energy limitations, and possibly other factors. Settlements should reflect a capacity reservation, mileage, and an accuracy adjustment. SCE also supports exploring designs which "immunize" Regulation resources from the Real-Time energy price.[12]

A final point on regulation is that the costs of regulation, even for intra-minute ZNE regulation, should be allocated based to those who create the need. Load is certain to be part, but not all, of the cause for regulation, as discussed *intra*.

8. Mileage and Performance Payments for RTIS and Regulation should be clearly defined.

SCE's assessment of mileage payments indicates that these payments are easy to understand at a conceptual level but can be difficult to apply. SCE requests the CAISO to further expand upon how they would administer a mileage payment for both RTIS and Regulation.

In addition to the mileage payment, SCE proposes that resources that do not perform according to dispatch signals be subject to no-pay clauses. This accuracy adjustment represents the application of cost-causation principles to ancillary services. One example of how this may work is a no-pay during any period where a resource does not perform to the CAISO's dispatch signal. This pay for performance adjustment would incentivize resources to adhere to the CAISO's dispatch signal, improving market efficiently. The FERC NOPR on Frequency Regulation (RM11-7) emphasized the need to reduce ACE based on the ability of a Regulation provider to track the ISO dispatch signal. No such reduction in ACE can be achieved without an incentive for the Regulation provider to ensure that they track the dispatch signal to the best of their abilities. No-pay clauses provide incentives to achieve this goal.

9. **Cost allocation of RTIS and Regulation should be based on cost-causation.**

The ISO's proposal represents a major advance in efforts to correctly allocate costs so that corrective behaviors have appropriate price-signals. This progress strongly aligns with the ISO's guiding principle of transparency and SCE strongly supports it, particularly for balancing and integration costs. Forecasting accuracy provides an example of how appropriate cost-allocation can yield more efficient market behavior. As previously mentioned, the application of cost-allocation principles to forecast accuracy is expected to reduce uncertainty and lower costs by lowering ancillary services needs.

SCE agrees that the costs of RTIS should be allocated to deviating resources. The ISO's 33% Study clearly indicates that large amounts of balancing services will be required to integrate high

[12] This is accomplished by paying Regulating resources their cost, rather than the market price.

penetrations of intermittent renewables. Cost-allocation principles should determine who bears the costs for RTIS so that an efficient market response results.

SCE believes the same should apply to the costs of regulation service. While load is certain to create some needs for regulation service through intra-minute changes in energy usage, it is clear that other system resources can create a need for regulation service. Solar PV resources, for instance, are known to have rapid fluctuations in output which will likely create need for system regulation. Additionally, in working in concert with RTIS, regulation will be providing some balancing service. SCE requests that ISO review data or other materials that will ensure decisions for cost-allocation for regulation are factually based. On this topic, SCE recommends the CAISO abandon the historic term "load following" when discussing general balancing needs. Instead, the CAISO should use the more accurate term of "Net Following" or "Following" to capture the sense that both load as well as other system factors, such as VERs and generation acting counter to CAISO instructions, drive the need for balancing.

VERs are likely to be the source of high amounts of both balancing and regulation reserves. Analysis by Bonneville Power Authority (BPA) shows VER balancing service reserves to be 2-3 times higher than that for following capacity reserve.[13] With two wind plants, the regulation requirement for wind in Puget Sound Energy's Balancing Area was still greater than the requirement for Load.[14] In Westar's analysis, using the stand-alone approach, wind VERs accounted for over 7% of the Regulation percentage while load accounted for 1.41%.[15] In the portfolio-wide approach, wind VERs accounted for over 4% of the Regulation Percentage while Load accounted for 0.68%. Based on these results, any Following service would be more VER Following than Load Following. These findings in other Balancing Authorities illustrate the need for appropriate cost-allocation for Regulation. SCE presented this in detail in its earlier RIMPR2 comments.[16]

10. The ISO should leverage internal and external stakeholder feedback while also relying on its guiding principles when consensus is unlikely.

The CAISO needs to allow ample time to ensure potential Market Design changes continue to be thoroughly vetted by stakeholders. Given the complexity and range of the CAISO's proposed changes, deliberation on the changes by stakeholders will be an important means of assessing the feasibility, merits, or pitfalls of proposed changes. In this case, key stakeholders will also include those internal to the CAISO, including its IT, and operations divisions. Like many other stakeholders, SCE strongly supports the goals of the RIMPR 2 and will need time to evaluate proposed changes and provide substantive feedback. While this process should not in any way prevent the CAISO from developing a comprehensive vision and road-map, it may require that the CAISO adjust its timeline. Similar to how the CAISO extended the comment period for the

[13] http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-05a.pdf
[14] FERC docket ER11-3735
[15] FERC docket ER09-1273
[16] Pages 10-14, http://www.caiso.com/Documents/Comments%20on%20discussion%20and%20scoping%20paper/SCEComments-RenewablesIntegrationMarketandProductReviewPhase2_Discussion_ScopingPaper.pdf. More recently, Puget Sound Energy also started allocating VER integration costs back to the VERs that cause them (FERC docket ER11-3735).

current Straw Proposal, SCE supports the CAISO providing extensions to the RIMVR schedule on an ad-hoc basis.

While SCE believes stakeholder input is essential for gleaning possible issues or problems associated with proposed RIMPR2 changes, the resolutions of such problems should be firmly guided by the CAISO's guiding principles and the three goals of the initiative. Based on the comprehensive nature of this redesign process, SCE expects that many market elements may change or be eliminated. Therefore, the CAISO will occasionally need to make market enhancements that result in the elimination of programs that are favored by some stakeholders. In seeking resolutions to issues, the CAISO should rely on its guiding principles and focus on the RIMVR goals when consensus is unattainable.

Summary

SCE supports the decisions to eliminate HASP and to rely on two settlements. The CAISO will need to address how it plans to settle and schedule imports at the interties. This is a critical issue toward any market design. The difference in scheduling and practice between the CAISO and other balancing authorities has created problems for the market over time[17]. The CAISO must focus on the details of the implementation of the two-settlement system toward imports in the absence of HASP.

Regarding the Real-Time Energy Dispatch options, SCE supports Option A as a workable format for restructuring day-of operations. SCE supports the idea of creating an explicit balancing product but has concerns with two key issues with RTIS that result from challenges in the dispatch interval and protocols for computer-to-computer dispatch. These issues include the need for RTIS to have a deep and liquid pool of resources and to limit the stranded capability of resources that could provide Regulation but are only dispatched to providing RTIS. Depending on changes made to RTIS, changes to the proposed frequency regulation product may be needed. These two products must work in concert to ensure adequate and economic balancing of the CAISO grid. SCE believes that costs for both of these products should be allocated based on cost-causation principles.

As the CAISO moves forward with the RIMVR and the RIMPR Phase II initiative, it should use this opportunity to shift towards a probabilistic optimization solution rather than a deterministic one as a way to better ensure it minimizes expected costs. It should continue to develop options for incorporating updated and more accurate forecasts and explore formal processes to get updated forecast information. In addition, SCE urges the CAISO to have its Operations department integrally involved in the design issues associated with RIMPR2, including robust participation in stakeholder meetings. Lastly, the ISO should resolve issues based on consideration of stakeholder input and on guiding principles, not solely on consensus.

[17] The Real-Time Imbalance Energy Offset problem is one of the most recent examples.

Appendix

Citation in Footnote 7.
Attachment Follows: “Integrating Variable Energy Resources while Maintaining Reliability: The Role of Integrating Services and the Importance of Proper Cost Allocation” by Nelson and Nelson.

Integrating Variable Energy Resources while Maintaining Reliability:
The Role of Integrating Services and the Importance of Proper Cost Allocation

By
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Policy and preference continue to drive increased Variable Energy Resources (VERs) penetration throughout all regions of the United States. In order to reliably operate the electricity grid in the presence of increased generation variability, studies and real-world experience indicate system operators require increased real-time operating flexibility. Typically these additional services manifest as some variation of increased regulation, ramping capability, following, or spinning reserves. Regardless of their exact specifications, securing these additional integrating services comes at a cost. This paper explores recent developments concerning VER integrating services, procurement mechanisms and cost allocation, with a focus on California, the Bonneville Power Administration (BPA), and the Federal Energy Regulatory Commission (FERC). It explores innovation and recommends areas of further exploration. Moreover, the paper argues that market and operational efficiency can be achieved by allocating related integration costs back the VER resources, based on cost causation principles. As demonstrated, this cost allocation approach produces superior short-term and long-term incentives when compared to several other alternatives.

All views and opinions are those of the authors and not Southern California Edison (SCE). The authors would like thank Dr. Aditya Chauhan for his insights.

Section I: Recent Regulatory and Market Developments Related to Renewable Integration

The integration of substantial quantities of intermittent resources has evolved from a theoretical possibility to now a practical mandate. Areas with significant penetration of wind and solar power continue to identify and define new operating challenges and continue to refine tools and techniques to deal with the increasing production uncertainty and variability added to their grid. Beyond local and often diverse responses, the prevalence of issues throughout the United States has elicited federal interest and involvement, particularly from the FERC, which generally characterizes intermittent resources such as solar and wind as "variable energy resources" or VERs.

At issue, supply intermittency presents a host of new operational challenges to electric grid operators. While traditional grid operations could be described, using broad strokes, as the process of serving variable load via controlled and dispatchable[1] resources, intermittent resources have caused on operational paradigm shift. Operators now must serve variable load with increasing amounts of *uncontrollable* and *varying* supply resources. While the operational problem has changed, the laws of physics governing grid reliability (e.g. the instantaneous requirement to balance production and consumption, maintaining frequency within a relatively tight tolerance, preventing voltage collapse, etc.) have not. Nor has the demand from policy makers, businesses and consumers for reliability.

Operational and market tools and techniques have no option but to change given this new reality. Many questions remain as to what issues should be expected, and what proven and what new approaches can most effectively and efficiently address the challenges. And the bottom line: how much will this cost and who has the responsibility to pay these integrating costs?

The following sections discuss recent developments related to VER integration, market developments and cost allocations. Section I focuses on policy questions asked by the FERC that will have national impact. Section II delves into real-world problems and how they are being addressed by the BPA in the Pacific Northwest. Section III concludes with a discussion of initiatives currently underway at the California Independent System Operator (CAISO), including their comprehensive "Renewable Integration Market Design".

<u>I. Activity at the Federal Energy Regulatory Commission</u>

[1] Defined by PJM (Pennsylvania-New Jersey-Maryland) Interconnection as "Generation available physically or contractually to respond to changes in system demand or to respond to transmission security constraints." – http://www.pjm.com/Home/Glossary.aspx.

The FERC's broad interests go beyond effectuating policy conducive for reliable grid operations, but more recently, for the effective integration of renewable generating resources. With VER penetration increasing in most regions of the United States, the FERC has taken an increasingly active role in examining developing operational issues, the need for new products, and addressing cost allocation for integrating services. A discussion on notable recent FERC activities follows.

Notice of Proposed Rulemaking (NOPR) on the Integration of Variable Energy Resources

On November 18, 2010, the FERC issued a proposed rulemaking related to the integration of VERs. Far from comprehensive, the rulemaking addressed three narrow, but important issues:

- Jurisdictional utilities must offer the option of 15-minute transmission scheduling in addition to the current hourly product.
- As part of the generator interconnection process, VER generators must provide their host balancing authority with meteorological and operational data to allow production forecasting.
- Transmission providers can develop a new generic ancillary service rate and charge generation for regulation capacity required to integrate the resource on the grid.

This NOPR resulted from an earlier the FERC Notice of Inquiry (NOI) issued January 21, 2010[2]. In that explorative process, the FERC sought comments on a more comprehensive series of integration questions surveying the importance of accurate production forecasting, shortcomings and incentives related to the current practice of hourly scheduling, market structure and the interaction of VER uncertainty in so-called "reliability commitment" processes in organized markets, benefits of consolidating balancing authorities to leverage VER error diversity and integrating capabilities, potential changes in existing ancillary services, modifications to capacity markets, and real-time curtailment and redispatch issues associated with VERs.

It appears the FERC's focus on the three issues in the NOPR resulted at least in part from the comments received on the NOI. These items had both consensus support and were generally viewed as implementable, with the possible exception of 15-minute scheduling. In contrast, other areas explored in the NOI met with either significant stakeholder resistance (such as consolidating existing balancing authorities), or had no clear path forward (such as changes to capacity markets).

[2] The NOI can be found at http://www.ferc.gov/whats-new/comm-meet/2010/111810/E-1.pdf.

Concerning the NOPR's requirement for 15-minute scheduling, its justification related to the benefits of accurate forecasting. The FERC proposed 15-minute schedule changes submitted no later than 15-minutes prior to the start of delivery. Thus, a party wanting to deliver 25 MWh during the period of 3:30 – 3:45 PM, would have until 3:15 PM to arrange the schedule.

Commenting parties generally agreed that to the extent VERs provided the grid operator with accurate production forecasts, this eased integration of their production. Further, particularly with wind, forecasts produced shortly before delivery (e.g., 15-minutes before production) have greater accuracy than forecasts produced well in advance of production (e.g., 1-hour before production). Moreover, since "flat through the hour" production may generally characterize output from conventional generation, VERs are more accurately characterized as "varying through the hour". Thus 15-minute schedules allow VERs to better match their schedules with anticipated production.

While meritorious on its surface, 15-minute scheduling presents both great challenges to the operational status quo, and only partially reduces operating burdens on grid operators. While exceptions exist, the bulk of the power system in the United States utilizes hourly schedules. This allows balancing authorities to coordinate the exchange of power through existing rules and systems, and allows time for material "manual" communication and coordination. Existing systems and rules simply will not accommodate routine 15-minute changes, and instead will, in the authors' opinion, require large regional changes to systems based on full automation of communication and coordination – a nontrivial exercise at best.

Moreover, even if perfectly accurate VER production forecasts were available 15-minutes prior to delivery, the operator still must have tools available to deal the variability and uncertainty of these 15-minute schedules. To see this, consider the following, exaggerated example. Assume a facility with a peak production capability of 100 MWh. 15-minutes prior to delivery it will know with certainty that its production will either be 0 MWh or 100 MWh. Next, at 15-minutes prior to delivery it develops a forecast and now has 100% confidence that production will be 100 MWh. The problem remains that at T-16M (16 minutes before delivery) the balancing authority had to be prepared to deal with either 0 MWh output or 100 MWh output. Just because the resource could forecast perfectly at T-15, it nevertheless burdens operations because of this potential *variability*. In fact, any actions the grid operator must take prior to T-15 to deal with both the variability and uncertainty receive no benefit from this perfect T-15 schedule.

Even if the unit could perfectly forecast its exact 15-minute production further in advance – even days in advance so that there is no *uncertainty* as to its production – the grid operator nevertheless must integrate the *variability* of this resource. As a further, exaggerated example, assume this same resource knew with certainty its production would be 100 MWh between 3:00 and 3:15 PM, 0 MWh from 3:15-3:30 PM, back to 100 MWh from 3:30-3:45 PM, and back to 0 MWh from 3:45 – 4:00 PM. Even if it guarantees this performance to the grid operator a day in advance, rather than 15-minutes in advance, the operator must have tools to "counterbalance" this certain variability. Of note, unlike traditional supply variability which is orchestrated to address forecasted load variability and scheduled supply variability, this supply varies without regard to changes in load, changes in generation or operational need. Thus, while 15-minute scheduling should help ease the integration of VERs to the grid, it does not eliminate the operating burden and cost of such integration.

Moving to the NOI's mandate requiring VERs to provide meteorological information to the grid operator, the FERC found significant consensus that as VER penetration grows, such information becomes essential for the grid operator to maintain reliability. However, several issues of contention remain. For example, debate continues over what particular VER resources must comply with this requirement. The FERC proposed requirements only for facilities 20 MW and over. Various other parties, including the CAISO, argued the requirement should apply to facilities 1 MW or larger. Also, the exact mechanism to implement the requirement remains under debate. The FERC proposed using the Large Generator Interconnection Process (LGIP), but other controlling documents, such as tariff rules in organized Independent System Operators/Regional Transmission Organizations (ISOs/RTOs) might be a more appropriate tool to dictate the terms. The FERC proposal would likely only enforce the requirement prospectively as new facilities interconnect, while a tariff-based approach might instead reach back to existing facilities that lack the telemetry, as well as to newly added facilities.

And finally, the third NOPR proposal related to the creation of a new generic ancillary service. Control operators have a clear case that integrating VERs, and their associated uncertainty and variability, has the potential to create operating burdens. In turn, these burdens require additional responsive services, such as regulation, in order to maintain grid reliability. The FERC's NOPR notes three separate cases where transmission providers have proposed mechanisms to directly allocate VERs the obligation and/or costs for these additional integrating services: NorthWestern, Puget Sound, and Westar[3].

NorthWestern proposed that wind generation exporting power would have to provide their own regulating service (either by forming their own balancing authority, dynamically scheduling, or by self-supplying all their regulation)[4]. The FERC rejected this proposal arguing that NorthWestern still had an obligation to provide imbalance energy. Puget Sound proposed a capacity "following service" to follow and balance the within-hour variation of wind in its balancing authority[5]. The FERC rejected this proposal because Puget Sound presented a tariff rate based on the cost of a hypothetical resource, rather than the actual costs of its existing resources. Finally, Westar proposed charging all generation (VERs and dispatchable) a regulation charge[6]. Cost would be allocated to generation in proportion to the relative regulating burden each facility placed

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[3] Under current law and FERC rules, transmission providers must seek FERC approval prior to charging any new rate to transmission customers.
[4] NorthWestern, 129 FERC ¶ 61,116, order on rehearing, 131 FERC ¶ 61,202.
[5] Puget Sound, 132 FERC ¶ 61,128 at P 4.
[6] Westar, 130 FERC ¶ 61,215 at P 1.

on the operator. The FERC accepted this proposal on an interim basis until such time the Southwest Power Pool consolidates and integrates an ancillary services market.

While the proposals differed, the theme remained constant: VERs are burdening operations, they require additional integrating services, and the VERs should pay for these services.

Rather than continue to look at proposals on a case-by-case basis, the FERC proposed a new ancillary service: Schedule 10 Generator Regulation and Frequency Response Service. This service allows transmission providers to charge generators for regulation capacity associated with the generator's variability. It applies whether generators are serving load within the balancing authority or exporting the power. Generators will either have to purchase this service, dynamically schedule their power, or self-provide their regulation. The service will have two components: a per-unit rate for the capacity and a volumetric requirement for each generator. While the FERC proposes the *per-unit rate* be the same for all customers, they recognize the *volume* required by different generation technology may vary (e.g., wind may require more reserved capacity than a nuclear facility). The FERC notes "reserve costs should be allocated to transmission customers consistent with cost causation principles", they leave it up to individual transmission providers to propose the methodology of determining needs and decomposing costs[7]. However, before different volume requirements can be placed on different technologies, transmission providers must 1) implement intra-hour scheduling, and 2) implement power production forecasting. Moreover, the transmission provider must demonstrate to the FERC that "different regulation volume is necessitated by that subset of [generators] delivering energy from [within its balancing authority area]" and that the volumes "are commensurate with their proportionate effect on net system variability … taking account of diversity benefits… supported with actual data collected over a one year period subsequent to the implementation of intra-hourly scheduling and power production forecasting for VERs."[8]

Notice of Proposed Rulemaking on Frequency Regulation Compensation in Organized Wholesale Markets

On February 17, 2011 the FERC issued a NOPR on compensation of Frequency Regulation in organized markets[9]. The NOPR focused on the payment structure for resources selling regulation. Both simulation and real-world experience indicate grid operators require increased regulation to integrate intermittent resources. Thus, demand for regulation is expected to increase. At the same time, the market has new technology options to provide regulation. The confluence of both increased regulation demand, and

[7] The NORP can be found at http://www.ferc.gov/whats-new/comm-meet/2011/021711/E-4.pdf
[8] FERC filing page 107
[9] Resources selling regulation have direct computer communication from the ISO/RTO to their resource. The ISO/RTO typically issues 4-seconds signals to vary the output of the resource. In the case of generation, the MWh output is controlled, in the case of demand response; the rate of consumption is increased or decreased.

options for new regulation supply have appropriately caused the FERC to focus on improving the regulation product.

The FERC indicates changes are needed in light of new technology, such as batteries, mechanical flywheels[10], and demand response, which have different operating characteristics from traditional generation-based providers. In particular, these new resources tend to have very rapid and accurate movement capability. However, in contrast to traditional generation, their ability to provide continuous energy over a long time horizon is typically severely limited. For example, a battery may have the capacity to provide 5 MW of “Regulation Up” (that is, to discharge the battery and inject power to the grid), and 5 MW of “Regulation Down” (to charge the battery and withdraw power). However, once the battery is fully charged or fully discharged, it can no longer provide Regulation Down, or Regulation Up, respectively. Thus, whereas a grid operator could increase the output of a traditional generator and hold the elevated output level indefinitely, the battery may run out of “charge” after only 5 minutes of increased output.

In the NOPR, the FERC argues that regulation ultimately provides Area Control Error (ACE) correction. Resources that respond quickly and accurately provide more ACE correction than slower resources that do not accurately follow the computerize 4-second dispatch signals. As a result, the FERC proposes providers of regulation receive payment for both 1) the total capability of regulation they make available to the grid operator, and 2) a payment commensurate with both the speed and the accuracy of the regulation provided. While all current ISOs/RTOs already compensate for item 1 (regulating capability), presently only the New England ISO has an explicit “speed and accuracy” payment.

While the general framework of rewarding fast and accurate performance appears technically and economically sound, it is the authors’ opinion that the compensation should also address the unique constraints of new technologies. For example, if the grid operator requires a resource to deliver additional regulation energy for ten consecutive minutes, but a particular storage device providing regulation (e.g., a battery) runs out of charge after five minutes, the “failure to perform” should be reflected in the compensation mechanism. For example, a portion of the otherwise “full performance payment” could be withheld, or as an alternative, the resource could receive a non-performance penalty. However, if the grid operator’s requirements could be fully met (e.g., only three minutes of continuous energy production was required) the resource should receive full compensation.

II. Activity at the Bonneville Power Administration

[10] Flywheels convert and store electrical energy into mechanical energy via a spinning mass. The mechanical energy can then be converted back to electrical energy by, in effect, slowing down the spinning mass.

The BPA operates the balancing authority covering the majority of Oregon, Washington and Idaho, as well as portions of neighboring states. It operates approximately 20,400 MW of federal Hydro and 1,500 MW of nuclear[11].

Given the large amount of its fast and flexible hydro system, coupled with wind-rich areas throughout its balancing authority, the BPA appeared a natural home to effortlessly integrate large amounts of wind. Or so went conventional wisdom. The BPA has, in fact attracted a great deal of wind. The BPA now expects to integrate about 4,000 MW by October, 2010, and is forecasting name plate capacity of almost 6,000 MW by September, 2013. And contrary to prior expectations of wind developers, wind is causing significant integration issues, and the BPA has had no choice but to address the issue of needed services and related cost allocation head-on.

The BPA's 2010-2011 Ratecase

The BPA develops rates, tariffs and many market rules and procedures on a two year cycle. Completed in 2009, the ratecase covering the BPA's fiscal years 2010-2011[12] produced groundbreaking rules related to wind integration services, cost allocation, and special operating rules to address wind events.

i) *Wind Integration Charges (WIC)*

This ratecase resulted in a new WIC – a charge applied to all wind facilities within the BPA's balancing authority based on installed name plate capacity. It consisted of capacity charges for three "balancing services": Regulation, Following, and Generation Imbalance. Wind received a separate charge for each service as tabulated below[13].

Regulation: $0.05 /kW/month
Following: $0.26 /kW/month
Generation Imbalance: $0.98 /kW/month
Total Wind Balancing Service cost: $1.29/kW/month.

For example, a participant with a wind farm having a 500 MW nameplate rating would be required to make an annual payment to the BPA of 500 MW*12 month*$1.29/kW/month*1000, that is ***$7.74 million***. This fee is simply for existing within the BPA's balancing authority. Additional charges apply for energy imbalance and other services to the extent actual production does not conform precisely to scheduled quantities.

[11] See http://www.bpa.gov/corporate/about_BPA/Facts/FactDocs/BPA_Facts_2009.pdf for additional BPA facts.

[12] The BPA fiscal year runs from October 1 through September 30. Thus the 2010-2011 ratecase covered the calendar dates from October 1, 2009 through September 30, 2011.

[13] See http://transmission.bpa.gov/business/Rates/documents/TR-10_Rates_Summary_Final_Proposal_Website_Posting.pdf for additional rate details.

In addition to these capacity based charges, wind purchased/sold imbalance energy at roughly the market rate for deviation within a tight tolerance. Deviations outside the tolerance faced, in effect, penalties.

Roughly speaking, the BPA defined the "Regulation" product as the four-second generation response needed to deal with deviations from 10-minute, intra-hour forecasts. The "Following" product handled longer-term errors based on the difference between 10-minute forecasts and hourly schedule levels. Historically, this same product was referred to as "Load Following". However, the BPA both observed and quantified that while a portion of this product was responding to changes in load, the majority was now needed to respond to variation in *generation output*, particularly wind generation. Thus, the BPA appropriately abandoned the misnomer "Load Following" and adopted the more general term "Following". The BPA defined the final product, Generation Imbalance, as the energy needed to capture residual error not accounted for by Regulation or Following.

The BPA's process for developing both the volume and rates of WIC relied on historical analysis and future projections of need. In summary, the BPA forecasted total needed operating flexibility to ensure grid reliability in 99.5% of all one minute events, and then decomposed the causation of this reserved capacity among wind and other classes of resources. Using cost-of-service principles they determined both the imbedded costs of the WIC capacity, and the opportunity cost losses of reserving this capacity for integrating services rather than for selling energy or capacity. These total costs were then allocated among resource classes based on their contribution to needs as determined via the decomposition study.

The BPA's innovative approach in determining operating need, and then decomposing this need based on causation among generation classes (e.g., wind, hydro, thermal), deserves additional discussion. A summary of the methodology, with an expanded discussion of INC Regulation, follows[14]. They began by decomposing each service into either "INC" (producing additional incremental energy) or DEC (decrementing energy output). The BPA observed that VER integration requires both directions of capacity. That is, if the wind blows faster than forecasted, wind facilities produce more energy than anticipated. As a result, some generation must be decremented to "make room" for this extra wind energy. Conversely, if wind dies off unexpectedly, wind resources produce less energy, and the operator must increment other resources to balance the system. Splitting out INCs and DECs, the BPA determines needs for the following:

1. Regulation INC (4-second response)
2. Regulation DEC (4-second response)
3. Generation Imbalance energy INC

[14] Detailed testimony on this methodology can be found at:
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-23.pdf
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-24.pdf
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-25.pdf
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-05.pdf
http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-BPA-05a.pdf

4. Generation Imbalance energy DEC
5. Following INC (ramping capability dispatched every 10-minutes) and
6. Following DEC

Based on historical data, the BPA determined their total system need for each service. In addition, the BPA performed a similar historic study looking at the needs for each resource class (wind, hydro, load) in isolation. For both the system-wide study, and the resource class-in-isolation study, the BPA determined the maximum requirements necessary to address needs during 99.5%[15] of one-minute operating intervals.

At the end of this exercise, the BPA had statistical data for total system needs, resource class needs in isolation, the total balancing reserve needs for the system, and the balancing reserve needs to address each resource class in isolation.

The BPA then decomposed the total system need into an allocation share for each resource class. The allocation proportion for any resource class was determined by the correlation between the balancing reserve need for the resource class in isolation, compared to the total need for the system. The allocation proportion to each resource class also considered the standard deviation of resource class need and the standard deviation of the total system need[16].

An example of this can be seen with the allocation to incremental wind regulation requirement:

$$Share_{inc}(wind) = Reg_{inc}(total) \times \rho_{Reg_{inc}(wind),Reg_{inc}(total)} \left(\frac{\sigma_{Reg_{inc}(wind)}}{\sigma_{Reg_{inc}(total)}} \right)$$

$where: \rho = correlation, \sigma = standard\ deviation,$
$Reg = regulation\ requirement,$
$Share = \ allocation\ of\ regulation\ to\ resource$

The BPA used this approach both as a way to determine what classes were driving the need for balancing reserve, and in order to give credit for "diversity" within the system. That is, errors in wind production may, at time, offset errors associated with forecasted load consumption. The correlation of individual resource class error to total system error captures this interaction. Moreover, by looking at INC and DEC data and services independently, the methodology binds the correlation between zero and one.

[15] This approach excludes 0.25% of its extreme incremental and decremental regulation values. This level of reliability was based largely on negotiations during the rate case between wind generation and the BPA, as opposed to ensuring compliance with a mandated reliability requirement.
[16] For example, in the 2011-2012 ratecase, the BPA determined its total system need for INC capacity (Regulation Up, Following Up, and Generation Imbalance Up) at a 99.5% reliability level as 1,032 MW. Of this, 281 MW were required to integrate load, and 679 MW were needed to integrate wind.

While far from perfect, the authors find the BPA's approach of identifying total system balancing capacity needs, decomposing this total need based on how each resource class contributed to the need (while accounting for diversity), and then allocating costs based on causation, both innovative and commendable.

ii) <u>Dispatch Special Order 216</u>

The BPA grappled with a balance between securing enough integrating reserves to maintain reliability while also trying to keep costs down. Parties debated what level of reliability the BPA should strive for. Addressing 100% of all possible events proved both infeasible and cost prohibitive. The BPA expressed preference for a 99.7% reliability level, but due to costs, wind generation argued for a 99.5% standard.

The BPA ultimately accepted a level to determine WIC quantities and costs of 99.5%. The BPA would still consider exports back by wind a "Firm energy[17]", however, they insisted on an additional reliability tool for extreme events: Dispatch Special Order 216, or simply DSO216. Under this protocol, the BPA monitored system availability of balancing reserves. If they exhausted 90% of these reserves, the BPA ordered wind to change production back to their schedule plus/minus their share of the balancing reserves. If the grid exhausted 100% of reserves, the BPA ordered wind to return to schedule (during over production) or the BPA cut export schedules to actual wind production (during under production).

Contentious at inception, controversy continues to escalate over this ability to cut export schedules from wind resources.

iii) <u>Persistent Deviation Penalties</u>

While recognizing that wind cannot forecast perfectly, the BPA grew concerned over both intra-hour errors, and cumulative errors resulting from persistently biased forecasts. Arguing that intra-hour errors created operating burdens, and persistent errors (such as the BPA consistently decrementing their hydro to make room for excess wind energy) created longer-term water management issues, the BPA adopted special scheduling rules for wind. Under the Persistent Deviation protocols, the BPA monitored scheduling errors over multiple hours. If a wind generator submits biased schedules (e.g., they consistently generate in excess of their schedule) for three consecutive hours, and replacement energy provided by the BPA was priced at the minimum of $100/MWh or 125% of BPA's actual replacement cost[18].

While the BPA expressed legitimate concerns, their protocol fell short of a solution. . Rather than encouraging accurate schedules in every hour, the protocol instead

[17] Firm energy is defined by the BPA as "Energy considered assurable to the customer to meet all agreed upon portions of the customer's load requirements over a defined period." – http://www.bpa.gov/corporate/pubs/definitions/e.cfm#energy

[18] See http://transmission.bpa.gov/business/Rates/documents/2010_Rate_Schedules_10_01_09.pdf, page 58 for additional details.

encouraged intentional "biased 3rd hour forecasting" after any two hours where forecasts errors had the same direction[19].

The BPA's 2012-2013 Ratecase

At the time of this writing, the BPA's 2012-2013 ratecase is ongoing. This ratecase uses the previous approach as the starting point and makes incremental adjustments. Also, with just under two years of actual operations, the shortcoming of the previous design, in particular the impacts of DSO216, have become more obvious and more material.

i) *DSO216 and Firm Exports*

DSO216 resulted in actual curtailments during 2010-2011, and these curtailments created controversy in the market. The BPA indicates that 41 such events were called in calendar year 2010[20]. At issue, the BPA continued to designate wind exports as "Firm" power – the highest quality of power sold in the Western Electricity Coordinating Council (WECC). Neighboring control areas and market participants objected whenever the BPA curtailed this "Firm" power under DSO216. They argued, in effect, that if the BPA had the right to curtail for non-contingency/non-emergency event, that the power was not "Firm".

In response, the BPA declared it would cease representing the power as "Firm", but instead would utilize a heretofore unused designation of "Generation – Firm Contingent", or G-FC. The wind community strongly objected, fearing that any change from "Firm" would materially lower the commercial value of their production. Testimony in the the BPA ratecase indicated non-Firm power traded at a typical discount of 20% compared with Firm power, if a market could be found for the power[21].

For this ratecase, the BPA has insisted on continuing DSO216, but has been prohibited by the Northwest Power Pool from labeling the power as "Generation- Firm Contingent". Parties in the Northwest and the WECC are trying to sort out the implications of power subject to DSO216, and are suggesting this power receive a new, as of yet undefined, classification. If the use of DSO216 continues, wind exported from the BPA will not be comparable to exports from other resource classes, but instead will be viewed as an "inferior product". While the FERC requires jurisdictional transmission providers to provide services so that wind can be "Firm", the BPA is not under the FERC's jurisdiction. However, the BPA policy to treat wind exports as inferior to exports from

[19] For example, if a generator forecasted 100 MWh of production in both hour 1 and hour 2, but actual generation was only 75MWh in both hours they "over-forecasted" for two consecutive hours. That party now has a strong incentive to "under-forecast" in hour 3 in order to avoid penalties.
[20] See Level 1 DEC Events tabulated at http://transmission.bpa.gov/wind/op_controls/fy10_dso216_summary_rpt_112210.pdf
[21] See testimony of Jeffrey Nelson, BPA-12-E-SC-01, page 3 found at https://www.bpa.gov/secure/RateCase/openfile.aspx?fileName=LAW-%231791270-v3-2012_BPA_Rate_Case__Direct_Testimony_of_Je.pdf&contentType=application%2fpdf

other sources in its balancing authority appears, in the authors' opinion, as inconsistent with overall federal policy in support of renewable energy.

ii) *Expanding the Decomposition of Balancing Reserves to Include Solar and Thermal Resources*

The BPA continued with the same general methodology of determining needs for Regulation, Generation Imbalance and Following balancing reserves as that used in the 2010-2011 ratecase. The same reliability level of 99.5% remains. However, they expanded the application beyond wind, and now subject solar and thermal resources to integration charges. Given the broader application, the BPA now refers to the charges as wind and solar as Variable Energy Resource Balancing Service (VERBS) , and for thermal resources, Dispatchable Energy Resource Balancing Service (DERBS). The proposed rates for VERBS are tabulated below:
VERBS
Regulation: $0.07 /kW/month
Following: $0.35 /kW/month
Generation Imbalance: $0.90 /kW/month
Total Wind Balancing Service cost: $1.32/kW/month.

iii) *Supplemently Balancing Service and Contingency Events*

In response to the BPA's position that wind generation purchasing VERBS will not be Firm, SCE asked BPA to offer the sale of supplemental services so the power could be "Firm". The idea being that with VERBS plus supplemental services, the frequency of DSO216 event would be sufficiently low that the market would accept the power as "Firm". Moreover, the Northwest Power Pool is developing protocols such that certain wind events will be considered "contingency events", which will allow the pool to utilize Spinning and Non-spinning contingency reserves[22] during certain wind events. The BPA has indicated a willingness to support supplemental service, but the details continue as a work in progress.

Section II: Activity in California and at the California ISO

California Renewable Initiatives

California's aggressive press for renewable power continued with several developments worthy of note. Until recently, the three major California investor owned utilities had requirements to deliver 20% of their total energy consumption from renewable resources

[22] The current proposal stipulates that contingency reserves can be utilized up to ten times per year, with no more than three events in a single month. Moreover, a balancing authority can only declare a contingency event if the unscheduled reduction of wind is at least 25% of the total wind nameplate capacity installed within that balancing authority.

by 2010. The actual 2010 numbers showed significant progress toward that goal. Of note, SCE reported renewable deliveries of 19.4% (14,548 GWh), with Pacific Gas and Electric close behind with 17.7% (or 13,760 GWh) and then San Diego Gas and Electric reporting 11.9% (1,940 GWh)[23].
On April 12, 2011 California's Governor Brown signed into law SB1X-2[24]. Among other items, the legislation effectively creates a 33% Renewables Portfolio Standard (RPS) by the year 2020. However, as part of his campaign, Governor Brown proposed 12,000 MW of localized energy and 8,000 MW of large scale renewables in addition to the 33% RPS[25]. Thus, the 33% standard created in SB1X-2 is likely the minimum level on renewable energy anticipated by 2020.

The CAISO Initiatives
In August, 2010 the CAISO completed a study with a detailed simulations of 20% renewable market[26]. The study simulated the impact additional VER resources to estimate impacts on Regulation and Following requirements. The report compared operating needs in 2006 against forecasted needs in 2012. Comparing these two years, the nameplate capacity of wind increased some 250% (from 2,648 MW to 6,688 MW) and solar increased over 500% (from 420 MW to 2,246 MW)[27].

The study indicates a material increase in both Regulation and Following needs. Table ES-1 from the report summarizes the increase in Following and Regulation requirements as a result of the increase intermittent energy. Regulation Up needs increase by as much as 37.3%, while Following Down needs increase by as much as 29.5%.

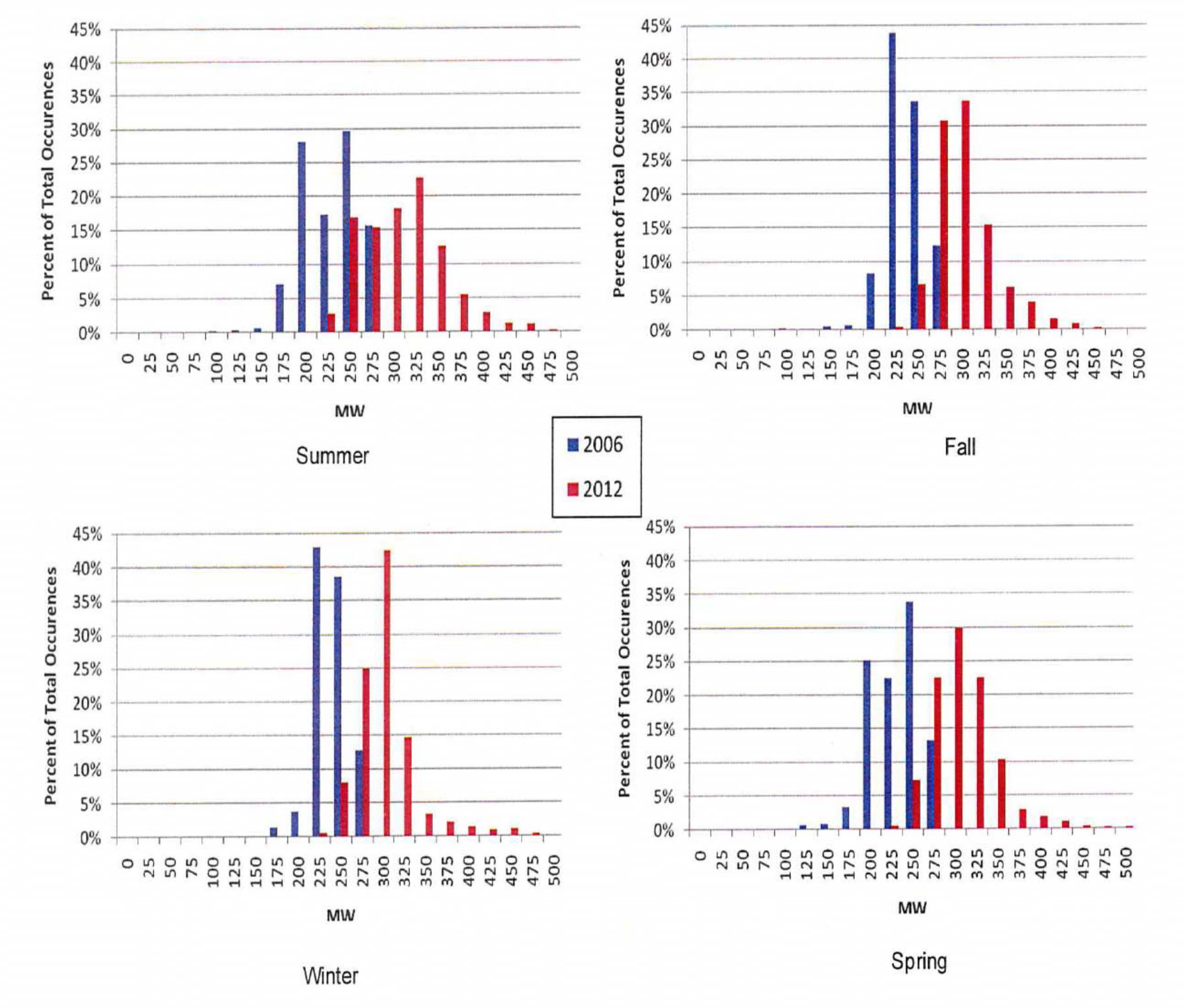
Table ES-1: Percentage Increase in Total Seasonal Simulated Operational Capacity Requirements, 2012 vs. 2006

	Spring	Summer	Fall	Winter
Total maximum load-following up	27.0 %	11.9 %	19.2 %	19.7 %
Total maximum load-following down	29.5 %	14.0 %	21.2 %	21.3 %
Total maximum regulation up	35.3 %	37.3 %	29.6 %	27.5 %
Total maximum regulation down	12.9 %	11.0 %	14.2 %	16.2 %

Figure A-5 of the same report details the increase Regulation Up need during all four seasons. The charts clearly show an increased Regulating burden during all seasons, with maximum requirements in 2012 approaching levels nearly double the 2006 requirements.

[23] See "March 2011 RPS Compliance Reports" found at http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm
[24] The text of the law can be found at http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[25] See http://www.jerrybrown.org/sites/default/files/6-15%20Clean_Energy%20Plan.pdf
[26] http://www.caiso.com/2804/2804d036401f0.pdf
[27] *Ibid*, Figure ES-1, page iv.

Figure A-5: Regulation Up Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Season

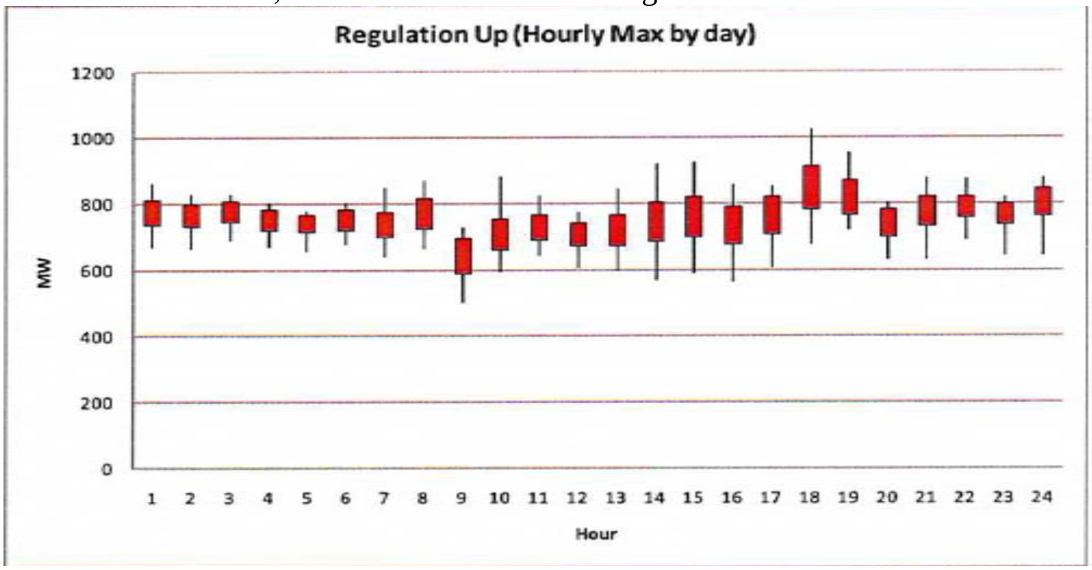


The report offered the following recommendations:

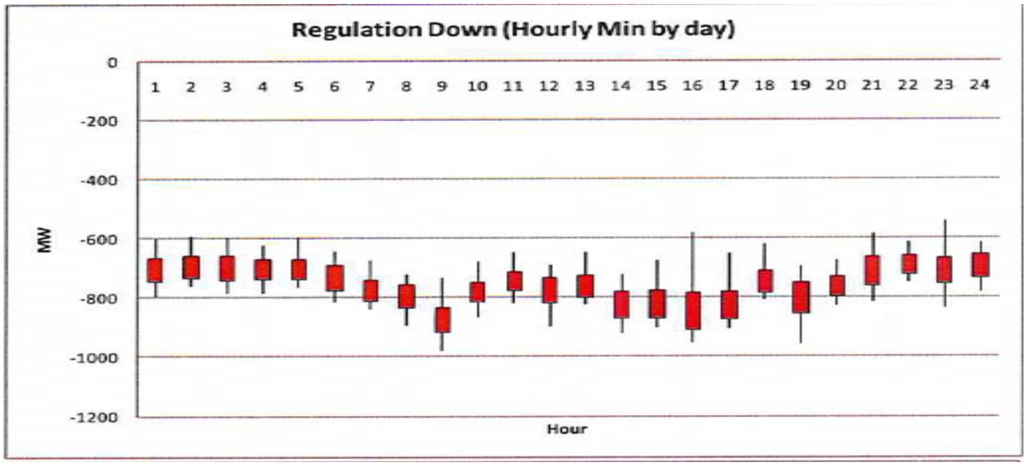
- Evaluate market and operational mechanisms to improve utilization of existing generation fleet operational flexibility.
- Evaluate means to obtain additional operational flexibility from wind and solar resources.
- Improve day-ahead and real-time forecasting of operational needs: Develop a regulation prediction tool and develop a ramp/load-following requirement prediction tool.
- Further analysis to quantify operational and economic impacts on fleet at higher levels of RPS.

As part of the California Public Utilities Commission Long-Term Procurement Plan (Docket R.10-05-006), the CAISO has begun analysis on the impacts of 33% RPS. On

May 10, 2011 the CAISO presented over 100 slides summarizing the methodology and results of current analysis[28]. The study looked at various build-out scenarios and evaluated impacts including operating needs, emission output, emission costs, and capacity factors of various resource types. Again needs for Regulation and Following services increased dramatically, when even compared to the earlier 20% study. As shown below, forecast for Regulation Up capacity during summer lie in the 700-800MW ranges with instances exceeding 1,000MW. This compared to a summer Regulation Up need in the 20% case, centered in the 275-375 range.



The presentation observed similar increases in Regulation Down needs, with requirements centered in the 700-800 MW need in the 33% case, as compared to the 200-300 MW typical need under the 20% case[29].



[28] http://www.caiso.com/2b73/2b73796015b90.pdf

[29] While centered in this range, the 20% study did have some hours with extreme needs. In particular, hour 18 had needs exceeding 700 MW.

The trend is clear: As variable generation increases its footprint in California, the CAISO will have an increased need for operational flexibility to respond to the new operating paradigm. According to the studies, today's Regulation requirements of 200-300 MW will nearly triple as California integrates these additional intermittent resources.

The CAISO Stakeholder Processes Focusing on Renewable Integration
Armed with analytical results, the CAISO realized both the immediate need, and the potential benefits of reforming its market design to more effectively integrate VERs. A host of stakeholder initiatives are currently in progress.

i) RIMPR Phase 1

On September 30, 2010 the CAISO officially kicked off the redesign effort with an issue paper release entitled "Renewable Integration: Market and Product Review"[30]. This initiated a process now referred to as RIMPR (pronounce "rim – per") Phase 1.

Phase 1's limited scope focuses on design enhancements implementable in the very near term (i.e., 9 months to a year-and-a-half). The CAISO deferred more comprehensive and material changes to Phase 2. The Phase 1 paper focused on several important, but relatively simple modifications to the existing market design:

- Obtaining greater operating flexibility through rule changes related to self-scheduling.
- Modification to the Participating Intermittent Resource Program (PIRP)[31] in order to give wind generation greater incentives to manage imbalances in real-time.
- Lowering the energy bid floor from the current level of -$30/MWh to a proposed -$1,000/MWh.
- Finalizing modifications to Regulation to allow greater participation by storage technologies (e.g., batteries and flywheels).

After much debate and process[32], the CAISO narrowed its focus on reforms to PIRP, lowering the bid floor, and finalizing regulation changes. At the time of this writing, only Regulation changes have received final CAISO Board approval. Concerning PIRP, the CAISO seems intent on eliminating the program so that wind resources schedule and settle in the same manner as all other resources on the grid. However, they continue to explore limited grandfathering options for existing participants. As for the bid floor,

[30] http://www.caiso.com/2821/2821c31a21680.pdf
[31] Under the PIRP program, participants must accept the CAISO's forecast for real-time production (developed about 75 minutes prior to the hour of delivery). In exchange, all deviations from this forecast are "netted" across the month. This net quantity is then charged the monthly average deviation-weighted LMP at the resource's location. The CAISO reports this has resulted in a subsidy to participants of about $1.30/MWh produced. In addition, PIRP rules prevent resources from submitting bids to the real-time market, rather the power is "self-scheduled" and cannot be dispatched by the CAISO except under extreme operating conditions.
[32] Please see http://www.caiso.com/27be/27beb7931d800.html for a full set of documents released by the CAISO.

while the market generally supports lowering the floor below -$30/MWh, there is no final answer on just how far it will be lowered. The CAISO has revised its proposal from -$1,000/MWh to -$300/MWh. However, the CAISO's Department of Market Monitoring (DMM), as well as some stakeholders, have opposed even this value over concerns of current market performance. The DMM suggests an alternative level of -$150/MWh[33].

Concerning changes to Regulation, on February 3, 2011 the CAISO received its Board's approval for the so-called "Regulation Energy Management", or RemReg for short[34]. RemReg addresses certain issues associated with technologies such as batteries and flywheels which, unlike conventional resources, have energy limitations preventing the continuous provision or Regulation Up (the sustained injection of power to the grid) or Regulation Down (the sustained withdraw of power from the grid). Under the proposal, the CAISO manages the charging/discharging of such resources with offsetting real-time energy purchases. Their objective is to better ensure RemReg resources have regulating capability available when needed. At the time of this writing, the CAISO has neither filed tariff language with the FERC nor developed software to implement the proposal. The CAISO targets early 2012 for implementation.

ii) RIMPR Phase 2

On April 5, 2011, the CAISO released the "Discussion and Scoping Paper on Renewable Integration Phase 2, Renewable Integration: Market and Product Review Phase 2"[35]. Here, the CAISO opened for discussion a broad and comprehensive range of market design issues including:

- New spot market products
- Allocation of integrating costs
- Modification to intra-day market settlements
- Long-term procurement (e.g., new generation build)
- Pay-for performance regulation
- Forward capacity markets
- Forward reserves markets

Rather than offering specific proposals for new market features, here the CAISO proposed a process to work through these issues. They expect to offer a "road map" for enhancements by the end of 2011.

The paper received a broad array of stakeholder comments generally supportive of the CAISO's commitment to focus on integration issues[36]. The authors note in particular the comments from SCE. The comments argue for the need to view intermittent integration as a foundational change in both grid and market operations, rather than simply a minor modification to the approach used for the past hundred years:

[33] http://www.caiso.com/2b82/2b82c0c5def0.pdf
[34] http://www.caiso.com/2b14/2b14899b24c90.pdf
[35] http://www.caiso.com/2b57/2b57efa839d50.pdf
[36] See http://www.caiso.com/2b6f/2b6fe40865ba0.html for all posted comments.

> The design should recognize a paradigm shift in the approach to grid operations and resulting cost allocation. The grid operator's goal is no longer just to "serve load", but rather they have an additional new goal: To efficiently and reliably integrate variable and intermittent supply. Uncertainty and variability brought to the grid by VERs will require integrating services and likely investment to insure the CAISO maintains the operating flexibility required for grid reliability. It would be a mistake to approach market design with assumptions that are simply no longer valid (i.e. all operating actions are done on behalf of serving load, ergo, load should bear all costs of operations) since the foundational role of grid operations itself is changing. With the changes in the generation portfolio, variability and uncertainty from the supply side must be addressed as part of the core market design. Continued assumptions that variability stems solely (or primarily) from demand would in turn result in an inefficient and potentially unworkable design, and likely an untenable market outcome in the short and long term. SCE stresses the need to decompose costs related to addressing variability and uncertainty and then allocate these costs back to the sources causing the costs. It is essential for the CAISO to scrutinize all operating actions, all requirements for products, and the quantity of products demands, and ask the following: Are we taking this action to (a) address load and its variability/uncertainty, or (b) to integrate supply resources and address their variability/uncertainty?[37]

iii) <u>Flexible Ramping Constraint</u>

Since initial operations of its redesigned market in April, 2009, the CAISO's real-time market has produced highly volatile, at times irrational real-time energy prices[38]. At core, the real-time market enforces constraints on a 5-minute basis, however prior to real-time the optimization views constraints as either hourly or at best 15-minutes in duration. As a result, while on a forecast horizon of an hour or 15-minutes the market optimization typically finds rational and reasonable solutions, in real-time there is no guarantee feasible 5-minute solutions exist. Of note, any variation in real-time conditions (either from load or generation) can create optimization problems relative to the hourly or 15-minute forecasted solution. Without market changes, inappropriate extreme real-time price excursion, as well as operational problems, will likely increase as the penetration of variable generation increases.

On April 19, 2011, the CAISO released a technical bulletin entitled "2011-02-01 Flexible Ramping Constraint"[39]. Under the proposal, the CAISO will enforce an additional

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[37] Comments of Southern California Edison, page 7, April 29, 2011 located at http://www.caiso.com/2b72/2b72e15122d90.pdf

[38] For example, the recently released CAISO 2010 annual report notes on page 161 "… most of the price spikes in the 5-minute market generally last only a few 5-minute intervals and reflect short-term modeling limitations, rather than fundamental underlying supply and demand conditions." The entire report can be found at http://www.caiso.com/2b66/2b66baa562860.pdf

[39] http://www.caiso.com/2b30/2b307b2a64380.pdf

constraint in the set-up of the real-time market. The new constraint ensures the dispatch used in real-time provides sufficient ramping flexibility (as determined by the grid operators) to address uncertainty of load *and generation* that is reasonably expected. The implementation date is uncertain.

While not perfect by any means, the authors view this as a positive development in evolving the market to better address uncertainty. This approach begins to solve operating and market constraints based on an expected distribution of possible outcomes, rather than on a deterministic single case. The latter often produces inflexible, and at times unpredictable and irrational results and is simply not sufficient given the uncertainty in both load and generation faced by the grid operator.

Section III: Cost Allocation Principles of VER Integration

With a system consisting of dispatchable generation, changes in output are due to customers' changes in demand caused by a combination of lighting needs, business process, and weather. The system operator purchases ancillary services to meet the unexpected deviations and then passes the costs onto load through a cost assignment charge, or an uplift charge. In the future, the cost of intermittency is increasing due to the increase of resources with highly variable fuel such as wind and solar. As noted, California recently passed a new state law requiring 33% of energy sales to be from renewable energy sources. To meet these federal and state renewable energy policy goals, the amount of VERs are a growing part of the renewable mix, and therefore the cost of VER integration is becoming significant. While load ultimately pays for the costs of integration, the path of the charges to the end-use customer is important if a least-cost outcome is desired. To achieve a socially economic, efficient outcome, policymakers need to consider the following three principles in developing cost assignment regarding the impact of VERs:

1. Cost causation
2. No undue discrimination
3. Take into account diversity

Cost Causation

The principle of cost causation is a widely accepted principle of cost assignment and is a standard endorsed by the FERC in establishing prices. Cost causation means that those that create costs should be held accountable; conversely, those that create benefits should reap the rewards. Furthermore, one entity causing more costs should also pay more than someone creating less cost. By assigning the cost to the entity creating the problem, they can decide to accept the cost or manage the cost by reducing the problem. It is through the market mechanism of matching marginal benefit versus marginal cost that the an outcome is optimal. Therefore, each party that contributes to a problem needs to be held accountable for their participation.

The principle of cost causation is very important because it provides the best incentive for source of the problem to take steps to mitigate or minimize the problem. Once there is a cost assignment, the source will then have knowledge to take the most cost-effective measures to reduce their cost assignment. For example, solar photovoltaic (PV) output has a steep ramp rate as the sun rises and sets during the day. If PV solar is a significant portion of the resource mix, then other resources will need to ramp very quickly which increases costs to the system.[40] However, if through a combination of electronics and battery storage, the PV ramp impacts of could be reduced, then this would reduce the Following cost to the system. It is unclear if this solution will be cost effective for every solar producer, but if they are held unaccountable for their ramping impacts, then the marginal benefit versus marginal cost decision will never be made by the producer.

The morning ramp of PV solar may also be a benefit to the system as it can match the needs of the system during morning ramp. If the proper controls and designs are installed then PV would reduce the system ramping needs. In this case, PV solar could receive payments for value of their ramping ability to match system load.

Another key outcome of proper cost causation principle is achieving the optimal amount of a VER technology to the resource mix. Failing to assign a particular technology's integration cost would make the resource look artificially cheaper than its true cost, which would cause too much investment in a particular technology. For example, assume technology A has very little capital costs, but very high integration costs, while technology B is slightly more expensive capital costs with very little integration costs. After a careful analysis, technology B would be the superior investment. However, if the project owners were never held accountable for their integration costs, then investors would always chose technology A, and this outcome would lead to a sub-optimal resource mix and higher costs to customers.

The role of exports and imports is also an important issue relating to cost causation. If one balancing authority is exporting large amounts of VERs, and then assigns the integration costs to their native customers, then the wrong party is paying for the cost. However, if the cost is assigned to the VERs, who in turn pass this cost onto their customer, then the right party will be assigned the cost. Once the right party is assigned the cost, then the marginal benefit versus marginal cost decision can be made.

While some solutions to reduce cost allocation may not be cost effective today, tomorrow they may become cost effective. Proper assignment of costs, and incentives, are needed to obtain a socially optimal outcome as an engine for efficiency and creativity.

No undue discrimination

The next principle is no undue discrimination, which is defined as being held to a reasonable and obtainable standard. For example, it would be unreasonable to penalize wind producers if they cannot produce at a given hour due to a lack of wind. However, it

[40] Solar thermal resources built in California in the 1980s have the ability to use natural gas to make up for cloud cover, which reduced the ramping impact.

is not discriminatory to hold a wind or solar generator accountable for the impacts caused to the system due to the uncertainty or variability of their fuel. Wind or solar should not be unduly penalized compared to traditional resources. In addition, each party that contributes to a problem needs to be held accountable for their portion of the problem. Certain groups should not be released from their contribution responsibility. Using the optimal resource example from the prior section, if the cost causation principle was relaxed, then a sub-optimal resource mix and higher costs to customers would result.

Take into account diversity

When determining the integration costs, system diversity impacts should be taken into account because it is the net impact that must be managed by the grid operator, not the individual operation. For example, assume there are two generators whose output is highly variable but reciprocal to each other. While individually they are highly variable, they exactly net out each other's variability to produce a flat load shape.[41] If they were charged for their individual variability, this would violate the cost causation principle because there is no system cost. Any cost assignment needs to take into account the cost impact onto the system. The difficult part is determining proper cost assignment of integration cost to the individual participants using the cost causation principle.[42]

Summary

The electricity industry is undergoing a paradigm shift that requires challenging operational assumptions in place for the last century. The grid must not only solve all the old issues, but now must also address the major new issue of integrating intermittent and largely noncontrollable renewable resources. Activity at the FERC, the BPA and the CAISO are indicative of the challenges that should be expected in all regions of the nation. While it is clear that integrating VERs creates additional operating burdens, how to minimize these burdens, and what products and protocols are most efficient for integration, remains a developing and unsolved problem.

While allocating integrating costs back to the VER resources driving the need has sound economic justification, policy makers have a difficult challenge in applying charges consistent with the principles of cost-causation, no undue discrimination, and accounting for diversity. While progress has been made, a full and complete solution has yet to be implemented. Policy makers are going to have to carefully determine if the application of the proposed tariffs will achieve social optimal solutions.

Some parties argue that the renewable integration costs are the result of public policy choices, and therefore the costs should be assigned to load. While customers ultimately pay for integration costs, it is the path to the customer that is important. Because many VERs investments are not cost effective compared to other generation resources, the contracting is being made to meet policy goals, which is already burdening customers

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[41] Diversity benefits may not always occur across the system due to system constraints.
[42] Another difficult issue is actually determining the integration costs due to VERs. This issue is beyond the scope of this paper.

with higher costs. If the role of VERs' impact to the system is ignored, not only does it violate the first principle of cost-causation, they have no commitment to minimize any integration costs. As a result, the efficient mix of resource technology would likely not materialize, and customers would be burdened with even higher costs that are necessary to achieve renewable portfolio goals.

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