CALIFORNIA PUBLIC UTILITIES COMMISSION

Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future

A CPUC Staff White Paper

11/25/2015

ACKNOWLEDGMENTS

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The authors would like to thank the CPUC Energy Division staff, especially those listed above, for their invaluable help in the drafting and reviewing of this paper. The authors also appreciate the contributions of CAISO staff (Delphine Hou, Nan Liu, Shucheng Liu) to the contents of this paper.

The views expressed in this White Paper do not necessarily reflect those of the individuals outside the CPUC-Energy Division.

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PREFACE

We, the Staff of the California Public Utilities Commission (CPUC), offer this paper to provide discussion material that will enable the CPUC to create an action plan for grid integration. This paper aims to inform and educate the reader and facilitate CPUC stakeholders in reaching a shared understanding of grid integration challenges and solutions. This paper puts forth for discussion the elements of a path forward, in terms of existing CPUC proceedings and programs, and also in terms of the incorporation of grid integration issues in any new planning process. This paper also emphasizes the magnitude and scope of the analysis required to properly identify the nature of the grid integration challenges and solutions.

We encourage the reader to consider the questions listed below. Where this paper may fall short in answering these questions, we invite interested stakeholders to provide further ideas and information. Our expectation is that comments from stakeholders will allow Staff to create the foundations for future action.

- **What We Need to Know.** What critical knowledge is the CPUC still lacking? What are the missing answers to key grid integration questions that may prevent the CPUC from launching policies to manage grid integration beyond 33%?
- **Possible Reliability Concerns.** Does this paper appropriately capture the most important "reliability signposts" of grid integration? As renewable procurement increases, which cost and reliability concerns merit the CPUC's focus?
- **Current Activities.** What actions are underway to address grid integration? Does the paper leave out important in-progress actions by California agencies to assist grid integration?
- **Short-Term Approaches and a Long-Term Vision.** How can the CPUC, over the next two years, enhance the approaches to grid integration that have already been identified? What is an appropriate long-term vision for grid integration?
- **Moving Forward on the Grid Integration Pathway.** What analyses should the CPUC pursue in the next two to three years, and how should these be pursued? How can we conduct a comprehensive review of the supply-side and demand-side approaches for addressing grid integration? How could CPUC, working with the California Energy Commission and CAISO, develop a vision and embark on a pathway towards long-term solutions?

Staff believes that "grid integration" is both an end-state and a process. *Our vision for an integrated electric grid of the future* is a grid that: operates seamlessly and reliably, produces much lower GHG emissions, includes large proportions of variable renewable generation resources, allows high adoption rates of electric vehicles to contribute to grid support, and allows a transformation in distributed energy resources of all types in providing energy, flexibility, and reliability services.

The process to achieve grid integration is to solve a set of three interlinked challenges, and to harness the opportunities created by these challenges: (1) to integrate wind and solar resources, in increasing amounts, onto the grid, particularly at the bulk or transmission level; (2) to respond to the changes in system-wide customer load due to increased rooftop solar installations and connected electric vehicles; (3) to bring about, in concert: changes to the characteristics of traditional resources, changes to the functionality and role of distributed energy resources, changes to operational and planning practices at both transmission and distribution levels, and changes to wholesale and retail markets and tariffs.

EXECUTIVE SUMMARY

California's Renewable Portfolio Standard and other clean energy policies put the state on a clear path to dramatic reductions of greenhouse gas emissions and a transition to a low-carbon power grid. The state is poised to achieve its 33% Renewable Portfolio Standard target on schedule, by 2020. In going beyond 33%, and especially in working towards the new Senate Bill 350 mandate for a 50% renewables target, a number of additional technical, economic, market, and policy issues are expected to arise. These issues could collectively be considered the "grid integration challenge." These issues arise in the context of a power grid that is undergoing rapid changes, including the portfolio of utility-scale generation, the daily pattern of energy use (load) and generation, and the quantity and role of distributed energy resources. The changes to the power grid are being driven by a wide variety of policies and market forces. This transformation of the physical power grid, in turn, is driving a changing paradigm for electric system planning and regulation, the core objectives of which are to ensure safe and reliable service at reasonable cost, while meeting environmental mandates.

As discussed in **Chapter I**, the characteristics of California's existing grid infrastructure have allowed for successful integration of significant amounts of variable wind and solar generation, and significant de-carbonizing of the electric sector, with only minor changes to grid operations to date. In 2015, record-breaking solar and wind production was observed for many consecutive days. As the shares of solar and wind generation grow, the need for grid operators to respond to the daily and seasonal patterns of solar and wind generators increases, and the system likely faces a mismatch between the daily peak of renewable generation and daily peak demand.

Nevertheless, the CPUC does not currently observe any clear signals that California's present trajectory toward 33% renewables has created unexpected and unmanageable reliability issues. However, in thinking about a renewables future beyond 33%, there are three emerging reliability "signposts" that point to the need to increase system flexibility and address grid integration in new ways. As explained in **Chapter II**, these three signposts are ramping ability, over-generation, and the need for ancillary services.

In terms of ramping ability, an extreme daily net-load shape with a 13 GW evening ramp occurring over a 3-hour period is predicted to occur by 2020. Occasional over-generation events have also resulted in part from increasing renewable output, but such events have so far been mitigated by curtailing renewable generation and therefore have not caused reliability impacts. However, the California Independent System Operator (CAISO) predicts that increasing renewable penetration may lead to frequent over-generation conditions in the future and significant amounts of curtailed renewable energy. It is unclear whether increasing curtailments of renewable generation is a cost-effective solution to over-generation in the long-term, or whether California should focus on developing more cost-effective alternatives. Finally, increasing penetration of wind and solar resources creates an increased need for ancillary services to respond to fluctuations and uncertainties, but wind and solar generators provide ancillary services less effectively than conventional generators, particularly under current designs and operations. Because of this situation, determining future ancillary services needs and the most reliable and economic means of meeting them is a critical part of planning for high levels of renewable generation. Therefore, Chapter II concludes that it is unlikely that the state will be able to cost-effectively achieve the Governor's new greenhouse gas goals, or to integrate the renewables necessary to reach 50% renewables, without further transformation of the electric grid.

As outlined in **Chapter III**, California has responded in significant ways to the grid integration challenge in recent years by implementing many practices and policies that assist grid integration. The state will continue to do so as it reaches its 33% Renewable Portfolio Standard by 2020. These practices and policies are distributed across a wide array of CPUC proceedings, CAISO initiatives, and California Energy Commission programs. For example, the scope of the Long-Term Procurement Plan proceeding has evolved in a number of ways to more directly assess the grid integration challenge through modeling flexible needs, curtailments, and integration costs. This proceeding has not yet found that grid integration challenges merit specialized procurement to meet a specific long-term deficiency. Nonetheless, initiatives and programs aimed at providing the system with more supply-side flexibility are underway in five main categories: flexible resource adequacy and must-offer obligations; storage procurement; CAISO market mechanisms; renewables procurement changes and valuation; and regionalization of real-time energy markets.

In addition to supply-side responses, California has initiated grid integration solutions that will aim to provide flexibility for grid integration via distributed energy resources and demand-side initiatives, including time-of-use and dynamic rate design, demand response program design, distributed storage, smart inverter standards, and plug-in electric vehicle integration. Studies are also being conducted to understand the potential of demand response and distributed generation to aid with grid integration. Finally, innovations in power system dispatch and control, including enhanced day-ahead weather forecasting, have greatly increased CAISO's ability to integrate renewables.

Chapter IV looks ahead to recommend how to expand upon the current activities described in Chapter III. To provide a stronger foundation of short-term approaches, Chapter IV presents a series of in-progress and possible "low regrets" or "no regrets" approaches that may provide additional flexibility. Examples of enhanced policies and programs include establishing time-of-use and dynamic rates, modifying net energy metering, and PEV charging tariffs to align with grid needs; considering new procurement targets for storage and flexible capacity; and adopting revisions to an "integration adder" to better account for the grid integration costs of renewables procurement.

Chapter IV also proposes a long-term vision for what the power grid of the future could look like if California fully incorporates grid integration into our planning, procurement, and operation processes. The vision is one of a grid transformed, wherein utility scale wind and solar are balanced through responsive load and other services provided by distributed resources. These resources could include responsive distributed generation, plug-in electric vehicle charging, and energy storage. The vision for supply-side flexible resources is seen in terms of "all-source procurement" and "all-source valuation," removing the distinction between "supply-side" and "demand-side" resources. Furthermore, the vision includes new conceptions of power system architecture that may redefine the operational, planning, and technical boundaries between the bulk-grid transmission system overseen by CAISO and distribution systems overseen by distribution system operators.

Chapter V presents a number of important primary analyses that must be completed so that the CPUC can understand how best to proceed toward the long-term vision laid out in Chapter IV. These analyses are necessary for the CPUC to proceed in an integrated and least-cost manner. Broadly speaking, the CPUC should quantify flexibility needs, consider all reasonable solutions to create flexibility, and attempt to understand their relative costs and time frames. More specifically, to arrive at the long-term vision of least-cost flexibility solutions, the CPUC should conduct the following analyses: (1) make improved assessments of flexibility, ancillary services, and other grid needs by examining the existing generation fleet, in addition to the emerging set of distributed energy resources; (2) conduct a cost-benefit analysis of all potential grid integration solutions, including supply-side resources, distributed energy resources, and market designs; and (3) assess least-cost pathways towards grid integration that account for all potential solutions. These could be easily coordinated with the SB 350 mandate for integrated resource planning

Before these analyses can be performed, the CPUC would need to create, with help from other agencies and stakeholders, the modeling and analytical tools to determine least-cost solutions to grid integration, beginning by determining what types of modeling approaches would be necessary to answer basic questions about least-cost solutions. This type of far-reaching and complex analysis may need to be overseen in a new type of "grid integration planning" process focused on understanding and addressing grid integration challenges, as well as coordinating with the ongoing efforts in various proceedings and programs.

Chapter V also suggests how grid integration planning could be accomplished through existing and future proceedings. To determine how best to answer the policy questions raised throughout this paper, the CPUC would need to consider making program changes and re-focusing proceedings. Grid integration planning could lead towards an action plan based on the results of the analyses recommended in Chapter V and focused on a long-term vision of an integrated grid. Policy questions to address through a grid integration planning process involve conducting flexibility cost-benefit analyses that cut across and encompass all relevant proceedings; targeting and enabling the role of distributed energy resources and load-modifying programs; incentivizing storage; procuring supply-side flexible resources; undertaking integrated approaches that combine supply-side resources and distributed energy resources; understanding future needs for ancillary services; and conducting greenhouse gas analyses.

While California is leading the way and faced with unique circumstances, it is not alone in facing the grid integration challenge. As outlined in Appendix A, many other jurisdictions around the world are also committed to integrating high shares of renewables. International experience points to curtailment and over-generation as growing issues internationally. A primary concern in leading countries like Germany, Denmark, Ireland, and China is wind power over-generation, whereas in California, solar over-generation is of greater concern. International experience also points to many issues and solutions such as increased attention to flexible conventional generation, enhanced power market designs, enhanced transmission planning, the appropriate contributions of storage and demand response, the means by which distributed energy resources can be part of the solution, and new ways to plan and operate distribution systems.

Further integration of high shares of renewable energy on California's power grid of the future will depend fundamentally on managing the variability and flexibility of resources. The means for achieving this future could be called the "grid integration policy path." This paper is intended to advance understanding, discussion, and ultimately consensus about policy-making along this path, and to help the reader understand that achieving the end-state of an integrated grid is possible, if given the appropriate attention.

LIST OF ACRONYMS

AAEE – additional achievable energy efficiency
AB 32 – Assembly Bill 32, Global Warming Solutions Act of 2006
AFV – Alternative Fuel Vehicles (proceeding)
CAISO – California Independent System Operator
CEC – California Energy Commission
CES-21 – California Energy Systems for the 21st Century
CHP – combined heat and power
CPUC – California Public Utilities Commission
CSI – California Solar Initiative
DER – distributed energy resources
DERGIS – Distributed Energy Resources Generation Integration Study
DERP – distributed energy resources provider
DG – distributed generation
DR – demand response
DRP – Distributed Resources Planning (proceeding)
EE – energy efficiency
EFC – effective flexible capacity
EIM – Energy Imbalance Market
ELCC – effective load carrying capability
EOM – energy-only market
ESDER – energy storage and distributed energy resources
FERC – Federal Energy Regulatory Commission
FRAC-MOO – Flexible Resource Adequacy–Must-Offer Obligation
GHG – greenhouse gas
GW—gigawatt
GWh – gigawatt-hour
IDER – Integrated Distributed Energy Resources (proceeding)
IEPR – Integrated Energy Policy Report
IOU – investor-owned utility (usually refers to PG&E, SCE, and SDG&E collectively)
IRM – Intermittent Resources Management
JASC – Joint Agency Steering Committee
kW – kilowatt
kWh – kilowatt-hour
LCBF – least-cost, best-fit (methodology)
LSE – load-serving entity
LTPP – Long-Term Procurement Plan (proceeding)
MOO – must-offer obligation
MW – megawatt
MWh – megawatt-hour
NEM – net energy metering
PEV – plug-in electric vehicles
PG&E – Pacific Gas & Electric
PV – photovoltaic
RA – Resource Adequacy (proceeding)
RD&D – research, development and deployment
RDW – rate-design window

RPS – Renewable Portfolio Standard
SB 350 – Senate Bill 350, Clean Energy and Pollution Reduction Act of 2015
SCE – Southern California Edison
SDG&E – San Diego Gas & Electric
SGIP – Self-Generation Incentive Program
SWIG – Smart Inverter Working Group
TOU – time of use
VGI – vehicle-grid integration
ZEV – zero emission vehicles

I. Introduction: The Changing Grid—Going Beyond 33% RPS

Why must California plan for grid integration when planning for a high renewable energy future? What aspects of the CPUC policy-making structure may require revision to address a challenge of this nature? What do we know about the changing grid and how could this knowledge lead to a new planning paradigm? What lies ahead on the "policy-making pathway" for grid integration?

The passage of the Clean Energy and Pollution Reduction Act of 2015 (SB 350) builds upon the 2006 Global Warming Solutions Act (AB 32)[1] in putting California on a clear path to dramatic reductions of greenhouse gas (GHG) emissions and the transition to a sustainable, low-carbon future. A major component of this transition has been the rapid growth of renewable energy for power generation over the past decade.

Actually, California's transition to a low-carbon grid began much earlier. The state has been a leader in renewable energy since the 1980s, and during the 1990s and 2000s, wind, solar, and biomass generation grew rapidly in California, in parallel with growth in several other leading U.S. states and countries worldwide. This growth was in response to both declining renewable technology costs and strong policy incentives. By 2011, California had raised its Renewable Portfolio Standard (RPS) to 33% by 2020, one of the highest shares of any state or national jurisdiction in the world. This 33% RPS became a key pillar of the state's GHG reduction plan.

California is poised to achieve the 33% RPS program target on schedule.[2] While the state seems well positioned to handle the 33% renewables level without major changes to other planning, procurement, or energy policies, CPUC Staff has concerns, echoed by many in state leadership, that going above 33% will create significant *grid reliability*[3] challenges, unless the CPUC comprehensively plans for grid integration. Staff's concerns have become more pressing since the Governor released very ambitious GHG goals via an executive order in early 2015,[4] followed by the passage of SB 350, which codified these GHG reducing measures.[5]

In going beyond 33% to realize a vision of a low-carbon grid, a number of technical, economic, market, and policy issues are likely to arise. These issues could collectively be considered the "grid integration challenge." From a technical and market point of view, concerns have emerged over how to manage the types of daily resource fluctuations inherent in a grid powered with significant quantities of *variable renewable energy resources*. Staff also observes that without proper comprehensive planning there will likely be reliability and cost impacts to the operation of California's *power grid*. Staff has recently observed a trend of *curtailment* of renewable generation, and if the trend continues in proportion to the increase in renewables, this may impact the state's ability to meet renewable and GHG goals in the most cost-effective manner possible.

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[1] AB 32 (2006), CA Health & Safety Code §38500 *et seq.*

[2] Based on current procurement contracts, California's three major utilities are each expected to reach 33% by 2020 or even sooner. SDG&E is expected to reach 33% by 2016.

[3] Throughout this paper, terms that are defined in the Glossary are introduced with italics upon their first use.

[4] *See* www.gov.ca.gov/news.php?id=18938.

[5] SB 350, signed into law by Governor Brown on October 7,2015, lays out a trajectory of 40% RPS by 2024, 45% by 2027, and 50% by 2030; see Pub. Util. Code§ 399.15(b)(2)(B). SB 350 also addresses electric vehicles, energy efficiency, and integrated resource planning.

The CPUC's long-term planning and procurement policies, including those governing both *utility-scale resources* and *distributed energy resources* (DERs), have evolved to meet the 33% RPS target. The California Independent System Operator (CAISO) has similarly adapted its electricity markets and grid operations. Evidence for these evolutions and adaptations can be seen in the extensive scope of ongoing work in many CPUC proceedings, as well as new and ongoing market initiatives by CAISO. Analytical work by the California Energy Commission (CEC) has also played a major role in helping the state plan for this evolution.

However, many questions related to grid integration will arise with higher renewable procurement that we cannot answer with currently available information. In particular, CPUC Staff sees a need for more analysis on the need for *flexibility*, the role of flexible resources, and how to ensure least-cost solutions. Many of the most obvious solutions to grid integration being considered in California and around the world could have higher costs, longer procurement timeframes, and sub-optimal markets. In particular, Staff has found indications that solutions like high levels of renewable curtailment, more *pumped storage*, and *transmission system* strengthening may be better understood at present but could be more expensive than other solutions, such as flexible DERs and innovative *rate designs*. Therefore, Staff recommends comprehensive analysis of all possible options, focused on the effectiveness, costs, and timescale of implementation. A variety of analytical approaches would enable the CPUC to better quantify grid integration challenges and reliability concerns, identify flexibility needs, characterize flexible resources, develop least-cost solutions, and guide procurement and market policy development in partnership with CAISO and CEC. Staff recommends that these analyses be a significant focus of the CPUC's time and resources in the next five years. This analysis will help the CPUC identify short-term, no regrets approaches, and navigate towards the vision of an integrated grid of the future.

A. Revising Policy-Making Structures

To implement the short-term approaches and achieve the long-term vision discussed in this paper, the CPUC's policy making structures may need revision in a number of ways. First, the siloed procurement structure created by governing statutes and policies makes it difficult to identify the most efficient and cost-effective solutions to grid integration. Staff observes that policies directing resource procurement should consider costs and benefits from a system perspective. The existing siloed structure of procurement programs into "supply side" and "demand side" also stands as a possible barrier to addressing in an integrated manner the mismatches of load and supply that will likely occur in a high-renewables future. Similarly, strengthening the relationship between generation planning and transmission planning becomes especially important.

Second, the CPUC's current approach of opening proceedings and developing programs to address one emerging technology area may not invite analysis that can consider the interrelationships holistically with other technologies or policy goals. While this approach has been very successful at increasing procurement of pre-commercial technologies, the grid integration challenge requires an integrative approach that encompasses all potential resource types and encourages comparison. In short, Staff observes that current programs and proceedings—even our comprehensive planning proceedings—may not be well structured to address the grid integration challenge, which implicates nearly all CPUC work in electricity programs and regulation.

Finally, one open question touched upon throughout this paper is to what extent the CPUC should pursue grid integration through market-based solutions versus mandated procurement of specific technologies. Other jurisdictions around the world are also facing this question. At present, California relies upon markets to set the price for energy and capacity, but federal and state laws and CPUC decisions simultaneously direct procurement of specific resources. The state has used command and control regulatory structures when it was concerned that markets alone would not sufficiently balance competing goals of efficiency and reliability. Because the state further decided that markets alone should not be responsible for ensuring sufficient resource supplies or diversity, as evidenced by the state's *Resource Adequacy* policy, it is harder to conceive of how markets can be primary tools for grid integration. On the other hand, markets clearly have an important role to play in the grid integration challenge, and this paper discusses a variety of market-based mechanisms for grid integration.

B. Understanding California's Changing Power Grid

What do we know about the changing grid? California's power grid has undergone fairly rapid transformations in recent years. These transformations have affected all aspects of the grid, including the generating resources that serve load, the transmission and distribution system that moves electricity to customers, and the load itself. These transformations can be traced directly to California's RPS and *preferred resources* policies. Before the RPS, California's grid used moderate amounts of renewable generation, coming mostly from large hydropower, biomass and geothermal generators. To reach the RPS target of 33% by 2020, California has embarked upon a massive infrastructure campaign over the past decade to add renewable generating capacity to the grid, much of it wind and solar. This has included significant new transmission projects to deliver renewable energy as well. In parallel, California's preferred resources policies, which have enabled the CPUC to follow a *loading order*[6] in procuring additional resources, have meant that higher priority has been given to procuring all available and cost-effective *energy efficiency* (EE), *demand response* (DR), and *distributed generation* (DG).

In addition to the RPS and preferred resources policies, the implementation of a wide variety of other renewable-energy and *load-modifying* policies has had a profound effect on California's power system, including *net energy metering* (NEM), the California Solar Initiative (CSI), the Self-Generation Incentive Program (SGIP), and the federal Production Tax Credit and Investment Tax Credit. These policies created stronger economic incentives for customer-installed DG for both commercial and residential customers, and especially incentivized distributed solar resources.

Together, these policies have led to a grid that is becoming physically and operationally very different from historical patterns. Some aspects of this changing grid include:

- Increasing quantities of variable renewable resources, i.e., wind and solar, most of which is not *dispatchable* by the CAISO, are coming online. While most of the existing pre-RPS renewable *generation fleet* was dispatchable hydro-power, geothermal and biomass, much of the added capacity under the RPS has been variable resources with "must-take" contracts, meaning that these resources do not economically bid into the *wholesale market*, and thus their energy goes onto the grid whenever they can generate.

[6] The loading order describes the priority sequence for actions to address increasing energy needs. For more information see the Energy Action Plan, 2005, *available at*: docs.cpuc.ca.gov/published//REPORT/51604.htm.

- The share of solar is rapidly increasing relative to other renewables. Due in part to significant reductions in the cost of manufacturing solar photovoltaic (PV) panels, solar is forecasted to contribute 45% of the total renewable generation mix by 2020,[7] almost double the 2014 solar share of 25%.
- Customer-installed generation, which is considered a load-modifying resource and is not dispatchable, has ballooned. Customer-installed solar grew from 500 MW in 2009 to 3.2 GW by June 2015, among over 400,000 installations.[8]
- The grid operator must now respond to dramatic changes in generation during certain times of the year. These fast changes are known as *ramping events*. The need for fast ramping was historically in response to load changes, but is now also due to changes in generation output.
- More distributed energy resources, such as demand response, plug-in electric vehicles (PEVs),[9] distributed generation, and storage, are interconnecting to the distribution grid, with potential to play an increasing role in CAISO markets.

C. The Changing Paradigm for Grid Planning and Reliability

How is our understanding of the changing grid leading to a new planning paradigm? The transformation of the physical power grid driven by California's GHG goals is creating a changing paradigm for electric system planning, the core objectives of which are to ensure reliability and cost-effective procurement while meeting environmental standards and preferred resource policies. The core planning objective throughout the previous century was to ensure reliability and universal access based on a presumption of unlimited supply of cheap baseload and dispatchable power. The generation planning process was simpler: California focused on developing electric generating resources to meet expected *peak load*, and also developed *demand-side programs* aimed at reducing both overall energy use and load during critical peak demand periods. The highest energy needs occurred on summer afternoons due to electricity demand for cooling, so California built a generation fleet that could meet the expected summer peak load. In addition to a large quantity of baseload power plants, the state relied upon a fleet of newer *load-following* (intermediate) gas-fired plants as well as a smaller fleet of "peaker" plants. Most newer plants operated as load-following throughout the year, ramping up and down according to load, but peaker plants operated only in the summer months, if at all. Now, because of renewable integration, the state must plan for reliability issues unrelated to peak load.

The historical focus on planning to meet peak summer load meant that the Commission's preferred resource programs—such as energy efficiency, demand response, and distributed generation incentive programs—were also designed to reduce peak loads and the need for new gas-fired generation. The performance and cost effectiveness of these programs have therefore been measured against those goals. For example, the cost effectiveness of energy efficiency programs is based on the avoided costs of building a new combined-cycle gas turbine plant. In general, such demand-side programs have been effective at reducing peak loads and avoiding the costs of building new peaking plants.

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[7] For estimates and a discussion of contributing factors, *see* Staff and consultant presentations from the February 2015 RPS Calculator Workshop, *available at*: www.cpuc.ca.gov/PUC/energy/Renewables/hot/RPS+Calculator+Home.htm.

[8] These figures include IOU data through Q2 2015 and publicly owned utility data through the end of 2014.

[9] This paper uses the term "plug-in electric vehicle" (PEV) to refer to both plug-in hybrid vehicles and electric-only vehicles.

This historical paradigm for power system planning is now changing, caused in large part by the high shares of renewable energy and DERs on the grid, and in smaller part due to changing energy-consumption behaviors and technologies giving customers better information and control. This paradigm shift in planning and reliability has arrived sooner than many predicted. By their nature, many renewable resources are not able to follow load (be dispatched) like other generators. Fortunately, California's solar generating output is generally highest in the summer months, when the weather is generally very sunny and the sun sets later in the day. On many days, the solar generating shape matches the load shape fairly well. But during very warm periods, a new "net peak" has emerged later in the evening, when the sun has set but Californians are still using power to cool their homes. Solar generation also does not line up as well with load on mild winter days, when the sun sets earlier, and heavy loads occur in the evening due to lighting.

Thus, while peak load is still a concern that must continue to be addressed through procurement policies, peak load is no longer the only planning concern or the most significant challenge. Rather, other concerns have emerged, including ramping, *over-generation*, and the need for *ancillary service*s. Central to these concerns is the issue of flexibility—i.e., the ability of both generation and load to respond quickly and in sufficient magnitude to balance out swings in variable renewable generation.

D. Policy-Making along the "Grid Integration Policy Pathway"

What lies ahead on the policy-making path for grid integration? It is now clear that California will be focused on the continuing evolution of the electric grid in order to achieve a 40% reduction in GHG emissions from the electric sector.[10] SB 350 provides a mandate for the CPUC to bring about this evolution by "[i]dentify[ing] a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner."[11] However, as already noted, it is not clear to Staff whether the current structure of policymaking at the CPUC is well-equipped to deal with a challenge of this nature and magnitude, and this may handicap the speed and efficiency at which policies and programs respond to indications of emerging needs.

If actions are not taken in the short-term, California may miss opportunities for least-cost solutions, and it will be much harder to thoughtfully craft integrated solutions in the longer-term. Conversely, adopting piecemeal solutions in the short-term that some see as a "magic bullet" for grid integration would similarly frustrate our ability to manage grid integration effectively in the long-term. Picking certain technology "winners," without thoroughly considering all potential cost-effective options, may inhibit future progress and impose higher costs on the state. It is critical that policy-makers balance the competing needs of early action with a comprehensive understanding of the costs and benefits of all feasible solutions, and the means for doing so is the "grid integration policy path" laid out in this paper. Progress along this path would mean that the challenges and recommendations discussed in this paper are considered in a comprehensive and thoughtful way, so that the most effective and efficient policies to address grid integration can be put in place through a strategic process, with the close cooperation of the CEC and CAISO.

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[10] As established by SB 350 (2015), Pub. Util. Code § 454.51 *et seq.*

[11] *Id.*

II. Signposts of Potential Reliability and Economic Impacts

What are the possible impacts on the reliability and cost of operating the grid if California neither plans most appropriately to accommodate increasing renewables nor institutes policy changes?

In this chapter, Staff discusses the “status quo” electric grid in California. We also present the highest-order challenges facing the grid in transitioning to a future with on low-GHG emissions, a higher RPS, and an increased reliance upon distributed energy resources. Specifically, Staff addresses observations, projections, and predictions regarding reliability metrics. Assuming that California will move forward rapidly in pursuing GHG goals and continuing to transform our electric generation fleet, what signposts might we observe that signal undesirable economic and reliability impacts?

Based on literature reviews and analysis recently conducted by CPUC Staff, stakeholders, and other agencies, Staff has identified ramping ability, over-generation, and the need for ancillary services as potential reliability “signposts” likely to arise on the path towards a grid with higher shares of renewables.[12] Each is considered in the context of the continued growth of renewables as a share of the state’s overall generation fleet. Staff does not currently observe any clear signals that our present trajectory toward 33% renewables has created unmanageable reliability issues. However, the intent of this paper is to aid the CPUC in preparing to address any issues that may arise on a higher renewable, lower GHG path.

A. The Electric Grid and the Continued Growth of Renewable Generation

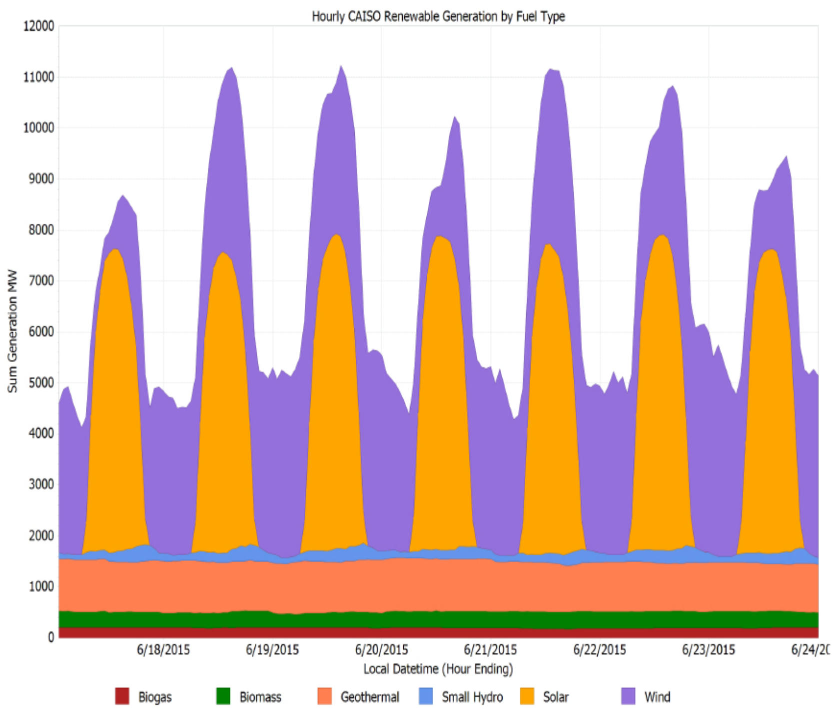
The challenge of operating a reliable electric system has always been one of adjusting the supply of energy to match fluctuating demand, in timeframes down to less than a second. Under the traditional utility model, this is accomplished with large, centrally-controlled fossil-fuel powered plants that can match customer demand as needed and respond to changes in voltage and frequency. Because continued dependence on fossil fuels is not sustainable in a GHG-constrained world, California has pursued—and will likely continue to pursue—reducing reliance on fossil-fueled resources, thus upending this traditional model. California will likely continue to rely on generating resources that can neither respond in the same way to load nor provide the same reliability services to the grid. With an expansion of renewable procurement policy in California, the expected future fleet of utility-scale renewable generation will be comprised of a large proportion of variable energy resources, i.e. wind and solar.

The RPS is a major tenet of achieving the state’s GHG emission reduction goals, but a renewable MWh seldom perfectly replaces a conventional MWh, so the emissions reductions from an increased RPS will not be one-for-one without thoughtful and careful planning. For example, the operation of fossil-fuel plants to balance variable renewables may force them to operate at higher heat rates, i.e., lower efficiencies. This will likely increase these plants’ emissions of GHGs and local criteria air pollutants. The GHG implications of operating a conventional fleet under changing conditions are not fully understood, and so analysis on this subject is discussed in detail in Chapter V.

[12] For an overview, *see* CAISO, 2013, “What the Duck Curve Tells us about Managing a Green Grid,” *available at* www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

Up to the present, the current available flexibility from all resources on California's electric grid has allowed for successful integration of significant amounts of utility-scale wind and solar generation with only minor changes to grid operations. However, as California integrates more variable energy resources, the need for system flexibility will increase. What is unclear is whether the increasing need will be linear or non-linear. The need for integration has been particularly rapid in 2015, as record breaking solar and wind production has been observed for many days in a row, a demonstration of the RPS resources continuing to come online. Overall, solar generation doubled in 2014 from 2013, reaching nearly 12,000 GWh. The significance of solar procurement is especially visible in spring and early summer. As shown in Figure 1, solar output exceeded 6,000 MW of generation on June 21, 2015. This equaled nearly 30% of statewide generation capacity on that date. However, a renewable generation record was more recently set in CAISO on August 19th, 2015, when total renewable capacity reached 11,604 MW. A solar generation capacity record of 6,408 MW was also set on August 21st.

Figure 1. Hourly Renewable Generation in CAISO's Service Territory—June 2015

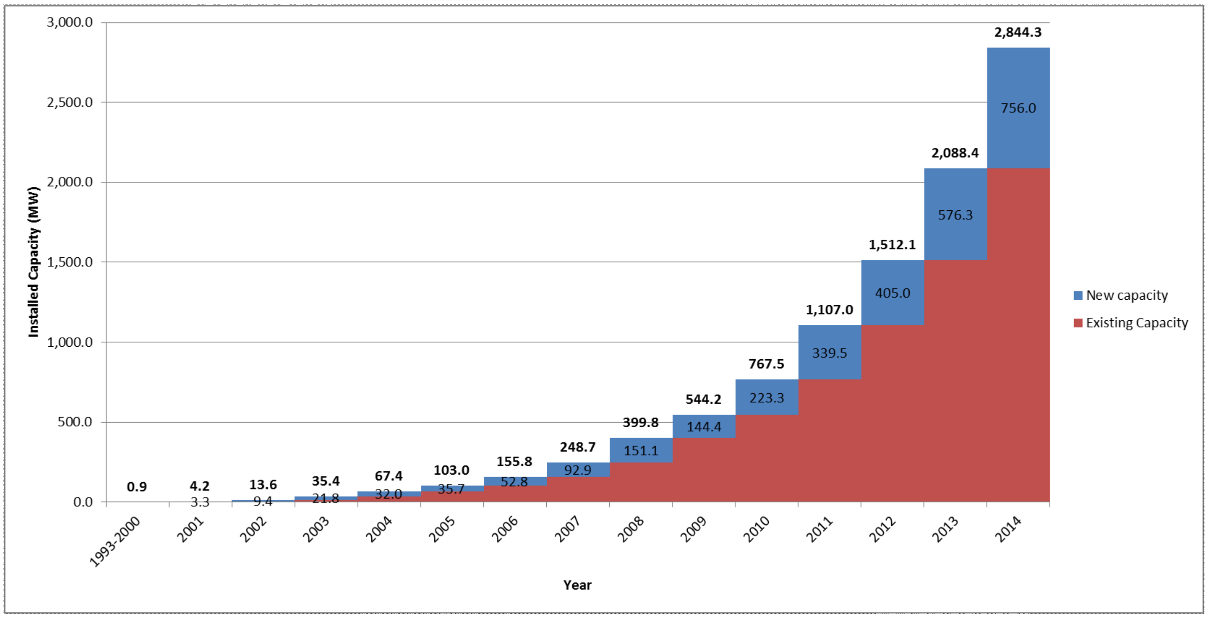


SOURCE: Southern California Edison, based on CAISO operational data

Having a renewable generation fleet comprised of a growing proportion of solar technology means that statewide electric generation potential becomes more dependent on the daily and seasonal patterns of solar irradiance. In contrast, wind generation has a more regular, less variable, generation pattern during a 24-hour period. Wind experiences seasonal variability, but less commonly does the state's fleet of wind resources simultaneously stop generating completely (like solar). The pattern created by large quantities of midday solar generation that disappears when the sun sets creates challenges to reliable operation of the grid and a potential mismatch between daily peak renewable generation and daily peak demand.

Concurrent with the wholesale renewable resource procurement by the investor-owned utilities (IOUs), there has also been rapid adoption by California residents and businesses of distributed solar resources, more commonly referred to as "rooftop solar." Figure 2 illustrates that deployment of rooftop solar generation has increased exponentially over the past decade, as the CSI program[13] has achieved a 39% compound annual growth rate since 2007. Figure 2 also shows rooftop solar energy capacity installed through 2014, which totals more than 2.8 GW. This growth rate was not predicted when California launched its CSI program. The CSI program has concluded, but even without this incentive, the adoption of customer-side renewable DG is predicted to continue to increase in the near term as long as NEM is not altered dramatically.

Figure 2. DG Solar PV Capacity Installed by Year



SOURCE: 2015 CSI Annual Program Assessment with updated data for POUs, compiled by the Energy Division

This increase is predicted due to rooftop solar's cost effectiveness from the customer and third-party solar lease provider perspective. Nearly all of this rooftop solar is considered by the CPUC, CEC and CAISO to be load-modifying whereas a smaller percentage of it is being used to demonstrate RPS compliance via the issuance of renewable energy credits. The CEC demand forecast predicts that customer-side DG will reduce peak load by more than 4,400 MW by 2024—nearly equal to triple the capacity of installations in 2012.[14] This is significant, but the actual expected rate of continued growth in this sector is difficult to predict, as it is dependent upon many factors, such as tax policies set by the federal government and the future of NEM (discussed later in this paper).

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[13] For more information about the CSI program, *see* "About the California Solar Initiative," *available at*: www.cpuc.ca.gov/puc/energy/solar/aboutsolar.htm.

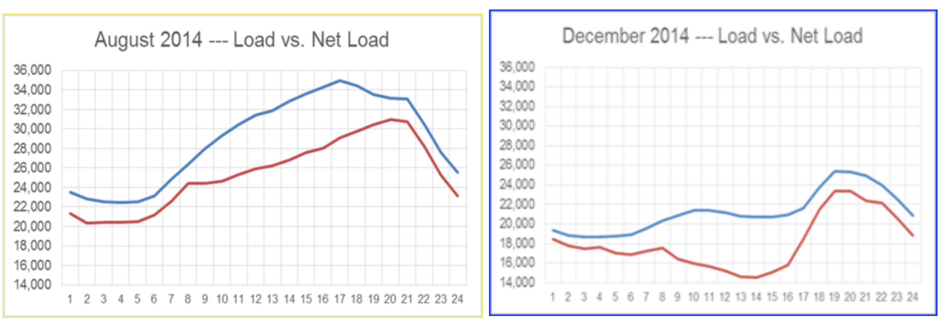
[14] CEC, 2014, "California Energy Demand 2014-2024 Final Forecast," Mid Case Scenario, at 39, *available at* www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf. (This data includes all DG resources, not only solar.)

B. Signpost of Reliability: Managing the Evening Ramp

When wind and solar resources are online, the remaining non-variable and dispatchable resources must be dispatched in such a way as to balance not only fluctuating demand, but also the variation and uncertainty[15] in the wind and solar generation. An important related concept is *net load*, which is defined by the industry as the remaining customer load that must be served after subtracting the energy provided by wind and solar generation. How quickly those non-variable resources need to change their output to match net-load is referred to as a ramping event, and the change in generation output is referred to as a ramp. It should also be noted that not all non-variable resources are dispatchable. For example, the type of nuclear plant operating in California can only operate in baseload mode and cannot adjust its output quickly. Similarly, some hydropower resources, such as dams, can quickly adjust their output, whereas run-of-the-river hydropower cannot.

The emerging concern over management of a steep evening ramp with sufficient flexible resources is a signpost of both reliability and of the potential economic impacts of integrating renewables. The following figures illustrate the concept of net load at different times of year, showing that the magnitude of ramping events varies dramatically throughout the year. The data presented in Figure 3 are drawn from actual CAISO operational data and represent the system-wide net-load shapes. In August the net-load curve follows the slope of the load curve fairly closely, whereas in December the two curves only mirror each other in the early morning and evening hours.

Figure 3. Load vs. Net Load in April and December 2014

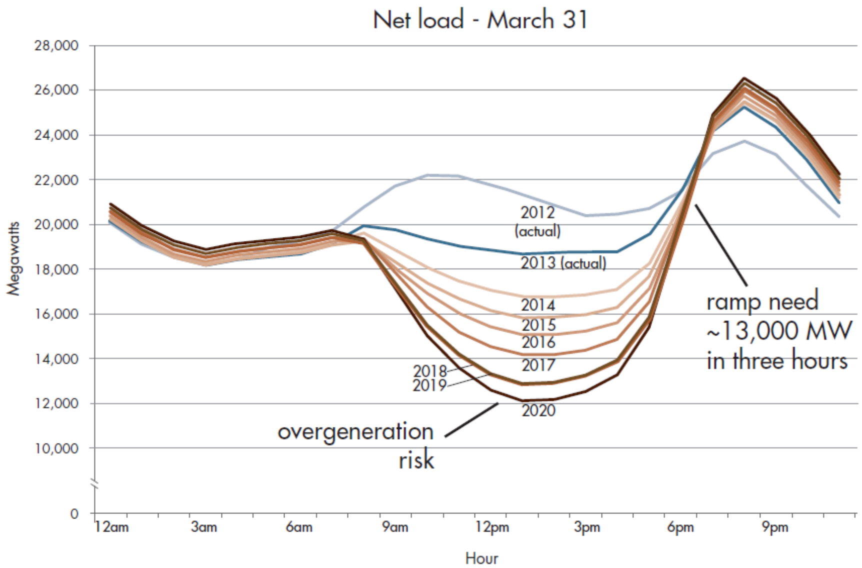


* Load is shown in blue and net load in red. SOURCE: 2014 CAISO Market Performance and Planning Forum

Because the trend of increasing solar penetration is expected to continue, the CAISO has modeled the potential for an annual extreme net-load shape, called the *duck curve*, several years into the future.

[15] Wind and solar generation variation can be forecasted, e.g. one can forecast stronger nighttime wind or solar when the sun shines, but there are large elements of uncertainty such as sudden wind changes or cloud cover.

Figure 4. CAISO's Duck Curve: Net Load Predictions through 2020



SOURCE: CAISO, 2013, "What the *Duck Curve* Tells Us about Managing a Green Grid."

The duck curve shown in Figure 4 is used to illustrate an extreme net-load shape: with a 13,000MW ramp over 3 hours predicted to occur in 2020. This condition is most likely to occur on a spring day when temperatures are mild and solar output is high (March 31st was used to create this curve). The duck curve also shows how low the system net load could potentially dip on a day with significant solar generation, thus representing a decreased need for other generation sources. The duck curve also represents how quickly solar generation could drop off in the evening hours, requiring a response from non-variable generators and/or storage. Therefore, the curve demonstrates two important concepts related to reliability: the potential for *over-supply* when the net-load curve dips very low, and the need for fast ramping to balance out the diminishing solar generation in the evening.

The primary methods for mitigating the phenomena of over-supply and ramping, as discussed in further detail below, are to create both flexible load and flexible supply resources that could either modify or mirror the net-load shape. In response to CAISO's predictions, CPUC Staff has studied the capabilities of the existing fleet to meet the potential ramp of 13,000 MW over 3 hours. CPUC Staff have found that our current fleet, which has many advanced combined cycle and simple cycle gas turbine resources that can operate in load-following mode, can respond to this ramping need.[16] The CPUC has also responded to this signpost by adopting rules around flexible resource procurement (discussed in Chapter III). The existing fleet also includes resources that have the physical capability to operate flexibly, but which may not be incentivized to do so by contracting or the energy market. Chapters III and IV discuss creating further incentives for flexible resources.

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[16] This conclusion is supported by analysis presented by SCE Staff at a CAISO FRAC-MOO working group meeting in August 2014, *available at*: www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx.

C. Signpost of Reliability: Over-Supply vs. Over-Generation, and Resulting Curtailments

Over-supply is a term used to describe a condition when the grid has more generation being produced from all of the resources on the grid than is needed, based on the load—in other words, an imbalance between electricity supply and demand. In a perfect electric system, an over-supply of resources should only occur when there has been an inaccurate forecast of either load, or of wind and solar output. However, as discussed below, the reality of balancing the grid is more complicated, and resources are not perfectly flexible and instantaneously dispatchable. During those periods when CAISO can no longer manage an over-supply condition reliably through normal market functioning, the system may experience what CAISO categorizes as an over-generation event.[17]

Thus far, occasional over-generation events may be the major negative—and possibly unexpected—consequence of increasing renewable output. These events have so far been mitigated by curtailing renewable generation and therefore have not caused reliability impacts. However, there is an economic cost to curtailing renewables, and reliability impacts may occur if over-generation events are frequent and require out-of-market responses.

Occasional over-generation events and more frequent renewable curtailment events are signposts of both reliability and economic impacts from integrating renewables. However, while curtailment and over-generation events are related, the causes of an over-generation event are not always the same as the causes of a significant curtailment event. For example, transmission congestion may lead to local curtailment but may not indicate system-wide over-supply or an over-generation risk. In other words, curtailment is one means of managing over-supply and over-generation conditions, but curtailments also result from conditions unrelated to over-generation.

1. Causes of Over-Supply, Over-Generation, and Curtailment

The factors that contribute to the occurrence of over-supply, over-generation, and the curtailment of renewables vary. First, as the duck curve illustrates, there is a diminishing need for baseload resources during certain months, suggesting that in the spring, a much lower proportion of baseload resources will be needed as RPS procurement increases. The current conventional generation fleet's capacity consists of a significant quantity of physically inflexible, baseload resources (such as the Diablo Canyon nuclear plant) that cannot ramp up or down quickly in response to market conditions or system needs.[18] Because many baseload resources have long-term contracts in place, the inflexibility of a certain percentage of overall fleet is a given for the near future. Similarly, even among the flexible generating resources, a significant portion of those have minimum performance operating levels ("Pmin") of at least 25% of their maximum output ("Pmax"). These factors could become more problematic with the increased RPS mandate. Second, it is not possible to perfectly predict how much power will be produced from solar at any specific time, due to changes in irradiance, or how much the

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[17] An over-generation event triggers a specific CAISO operating procedure. *See* CAISO, 2015, "Operating Procedure," Effective October 22nd, *available at*: www.caiso.com/Documents/2390.pdf.

[18] The following RA resources are considered "inflexible": Diablo Canyon Nuclear Power Plant (approx. 2200 MW), CHP facilities (or "qualifying facilities") (approx. 3,800 MW), gas-fired plants without an EFC, older biomass plants (35 MW), and run-of-river hydropower.

wind will blow during certain hours of any day, even though we have very sophisticated models that are constantly improving to predict wind and solar output. Third, even with the IOUs' and CAISO's advanced weather forecasting models, it is also impossible to perfectly predict temperatures, which are a significant driving factor in customer load due to cooling needs and thus a primary driver of system load.

Therefore, an over-generation event could be caused in part by conventional resources being dispatched unnecessarily in the *day-ahead market*, and then not being able to—or not directed to—ramp down sufficiently to accommodate solar or wind generation. It may also be that the grid operator believed the conventional resources would be needed to meet the afternoon ramp and wanted them to be online to maintain reliability. Over-predicting load or under-predicting solar and wind output would increase the difficultly in managing such conditions.

A compounding factor that can lead to renewable curtailments, unrelated to system-wide over-supply, is transmission congestion. Congestion can contribute to the curtailment of renewables even when the overall system is not experiencing an over-supply condition, because many utility-scale renewables projects are located in the same geographic transmission area, and load is often not in close proximity to generators.

2. Background on Economic and Manual Curtailments

In the CAISO wholesale energy market, generators reflect their marginal cost of operation through their bid price. When the bid price for any interval is higher than the market-clearing price, this indicates that the generator would prefer not to produce electricity because the cost of operation will be higher than the market payment. It should be noted that many generators in the CAISO are unresponsive to changes in real-time market prices because they have "self-scheduled" their generation, meaning they have chosen to generate regardless of market price, and therefore act as price-takers in the real-time market.

Technically, an economic or "market" curtailment occurs in the *real-time market* whenever a generator's bid price is higher than the market clearing price for a given interval. When there are low prices driven by over-supply, resources with higher operational costs undergo *economic curtailment*, beginning with generators with the highest price and continuing to those with the lowest bid price. A related phenomenon is negative pricing. A *negative market price* also typically indicates there is an over-supply of generation, which indicates that more electricity is being produced from resources on the grid than there is load. This can occur at a particular location (local) or across the grid (system-wide). However, negative prices in one location can be driven only by congestion, not over-supply, as discussed later.

Occasionally, certain generators (usually wind and solar) prefer to keep putting power on the grid during a negative pricing interval, even when they will incur a cost rather than receiving a payment from the energy market. It is generally only wind and solar resources that are willing to take a negative price, because they are often receiving other payments associated with their energy generation (such as from their long-term contracts, sales of renewable energy credits, and through production tax credits). What this also indicates is that some generators are unable or unwilling to shut-off generation, and those willing and able to curtail will have a strong incentive to do so. Because wind and solar resources typically have the lowest bid price, they are the last to be economically curtailed in order to maintain supply and demand balance in the market. In general, during an economic curtailment event, many non-renewable resources can be curtailed. In contrast, when the market cannot or does not sufficiently deal with an over-supply or congestion condition, CAISO calls for a *manual curtailment*, meaning it directs specific generators to stop generating through "exceptional dispatch." CAISO has recently used manual curtailment of renewables to mitigate over-generation.

3. Curtailment Observations

Based on CPUC Staff and CAISO analysis,[19] congestion appears to have caused more curtailment events than system-wide over-supply or over-generation events in the past 18 months (from early 2014 to late 2015).[20] CAISO refers to congestion-related curtailment events as *local curtailment* and over-supply-induced curtailment as *system curtailment*. At current levels of renewable energy penetration, observed over-supply events have occurred mostly in winter and spring months, and have been mitigated by the CAISO either through manual curtailment (directing renewable generators to remove their generation from the grid) or, more recently, economic (market-based) curtailment. The few over-generation events that have occurred have required manual curtailment through exceptional dispatch to reduce generator output.

As shown in Table 1, in 2014, total renewable curtailment in CAISO was around 36 GWh. For comparison, about 44,000 GWh of renewable energy was delivered to the CAISO grid in 2014.[21] Most of the curtailment observed in 2014 was economic or market-based, rather than manual or ordered curtailment, and it mostly occurred in spring and fall. Approximately 11 GWh of economic curtailment occurred in May 2014 and 15 GWh total from October through December. In contrast, only roughly 2.2 GWh of manual curtailment occurred in 2014. In April and May 2014 CAISO implemented two significant changes to the market. One was to lower the bid floor (allowing prices down to negative $150/kWh). The second was to encourage economic responses from wind and solar generators, part of implementing Federal Energy Regulatory Commission (FERC) Rule 764.[22] Once these two changes were implemented, manual curtailments have comprised only a small fraction of overall curtailments.

The quantities of curtailment that occurred in 2014, as shown in Table 1, were higher than previously anticipated by CAISO. In context however, the absolute amount of curtailment is still small compared to total annual RPS-eligible generation in 2014, roughly equal to less than 0.1%.[23]

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[19] CPUC and CAISO Staff conducted this analysis in September 2015. Details cannot be shared due to the confidentiality of market sensitive information.

[20] According to CAISO, there were three system over-generation events in 2015.

[21] *See* generation totals of small hydro, geothermal, biomass, wind, and solar for the year 2014, compiled by CEC and *available at*: www.energyalmanac.ca.gov/electricity/electricity_gen_1983-2014.xls.

[22] *See* "FERC Order No. 764 market changes," *available at*: www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrderNo764MarketChanges.aspx, and www.caiso.com/Documents/Mar20_2014_OrderConditionallyAcceptingTariffAmendment-Order764_ER14-480.pdf.

[23] Less than 0.1% when total 2014 CAISO balancing area curtailment is compared to statewide 2014 total annual RPS-eligible generation (which excludes large hydro).

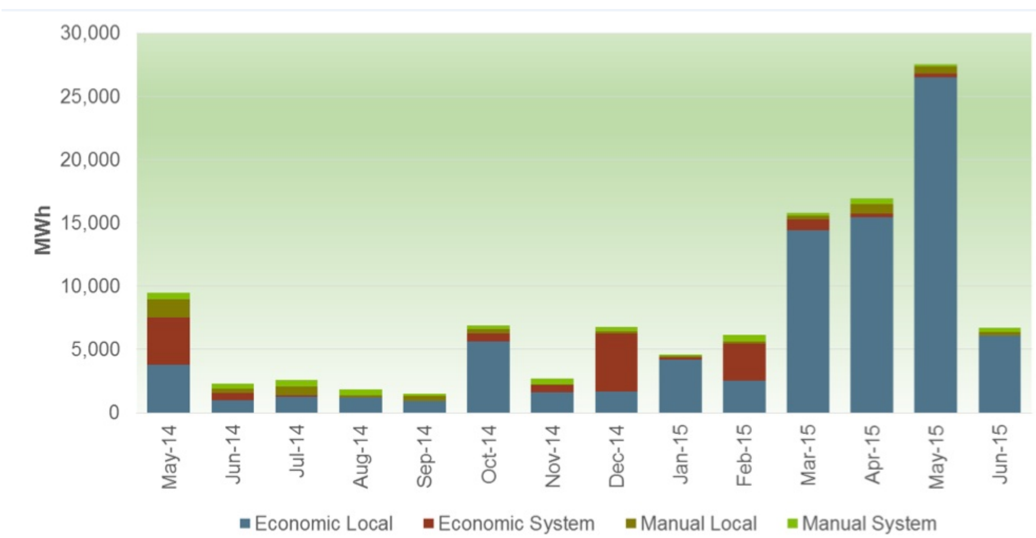
Table 1. Renewable Curtailment Data Provided by CAISO*

2014 Month	Manual curtailment (MWh)	Economic curtailment (MWh)	Total curtailment (MWh)
Jan	0	0	0
Feb	288	0	288
Mar	123	0	123
April	1342	0	1342
May	442	11364	11806
June	0	2461	2461
July	0	1845	1845
Aug	0	1274	1274
Sept	0	909	909
Oct	76	6039	6115
Nov	0	2615	2615
Dec	0	6757	6757
Total	2271	33265	35536

*Curtailment data is the total for all 15-minute intervals during each month. SOURCE: Data provided by CAISO to CPUC in August 2015

As demonstrated in Figure 5,[24] the frequency of economic curtailment in the CAISO markets in May 2015 is nearly 2.5 times higher than May 2014. However, most of the economic curtailment was "local," meaning it was congestion-related. The quantity of congestion-related curtailment in the spring of 2015 (indicated by economic local curtailment) was also much higher than in 2014, and CAISO attributes this mostly to congestion at the critical "Path 15" transmission area caused by major maintenance underway at that time.[25]

Figure 5. Quantity of Economic vs. Manual Curtailment in the CAISO Markets from May 2014 to May 2015



SOURCE: CAISO, 2015, Market Performance and Planning Forum.

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[24] Graphic is from CAISO, July 2015, "Market Performance and Planning Forum," *available at*: www.caiso.com/Documents/Agenda-Presentation_MarketPerformance-PlanningForum_Jul21_2015.pdf.

[25] For an overview of "Path 15" and the maintenance project, *see*: www.datcllc.com/projects/path-15/.

Separate from curtailment, the market also had many negative pricing intervals in the spring months. In May 2015, on average, 15% of real-time intervals had negative energy prices. For one week in May 2015, 20% of real-time intervals had negative prices, whereas in May 2014, the frequency did not exceed 5%. The negative prices corresponding with this increased frequency reached the price floor of negative $150/kWh in May 2015. The CAISO Department of Market Monitoring attributes these negative pricing events to a combination of record solar output, low load conditions, and some transmission congestion. While it is impossible to say how much each factor contributed, Figure 5 demonstrates that CAISO classified nearly all of the economic curtailment events in March-June 2015 as "local," meaning that congestion played a significant role in these events. Given that 2015 to date is a year with record low hydropower generation, CAISO has concluded that over-supply conditions and resulting negative pricing events would have been more frequent if hydropower had been operating near its full capacity in the spring (which is generally the highest point of the year).[26]

In conclusion, there have been tangible economic effects from over-supply conditions and the resulting economic curtailment of renewables. While over-generation events have occurred, they have been infrequent and CAISO has been able to manage them with manual curtailments so that reliability was not compromised.

4. Over-Supply and Over-Generation Predictions in Long-Term Modeling

Increasing renewable penetration may lead to more common over-supply conditions in the coming years, which would be most prevalent in the spring. Also, predictions indicate that the current trend of curtailment of solar resources will likely continue to increase somewhat over the next few years. Over-generation events could therefore result when the market response to over-supply is insufficient, and this could happen more frequently. However, various studies and modeling done through the 2014 Long-Term Procurement Plan (LTPP),[27] the RPS Calculator 6.0,[28] and the CES-21[29] effort generally lead to the conclusion that over-generation and resulting curtailment would not create significant reliability or economic concerns at a 33% RPS.

Many modeling projects are underway to better understand the range of likely over-generation levels and renewable curtailments in the near term. The RPS Calculator was first developed in 2009 as a planning tool to forecast the amounts, types, and locations of future renewable energy and transmission development needed to meet the renewable portfolio standard. It has undergone revisions to reflect and anticipate major technological and market changes occurring in the renewable energy industry. The newest version of the calculator, 6.0, is addressing and attempting to predict quantities of renewable curtailment in the next 10 years. Version 6.0, although still in draft form, models integration challenges that future additional renewable energy development in California faces, including declining capacity value, potential over-generation, and

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[26] CAISO, 2015, FRAC-MOO 2 Working Group presentation, July 22nd, *available at*: www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx.

[27] *See* "Long-Term Procurement Plan History," *available at*: www.cpuc.ca.gov/PUC/energy/procurement/LTPP/ltpp_history.htm.

[28] *See* "RPS Calculator Home Page," *available at*: www.cpuc.ca.gov/PUC/energy/Renewables/hot/RPS+Calculator+Home.htm.

[29] California Energy Systems for the 21st Century (CES-21) is a collaborative research project between the IOUs and LLNL authorized in D.14-03-029, which modified D.12-12-031. A portion of this research is dedicated to development of modeling tools to measure the level of system reliability and flexibility in the system under a range of conditions. *More information is available at*: www.ora.ca.gov/general.aspx?id=1864.

related curtailment. The calculator generates a range of possible curtailment amounts under different scenarios.[30] It predicts that there will not be a significant increase in curtailment caused by over-supply between now and 2020 under a 33% RPS. However, if the RPS were increased to 50%, the low range of curtailment predicted in 2025 is approximately 600 GWh, representing 0.7% of RPS generation. The high end is predicted to be around 1.7% of generation, or 1,550 GWh.

Studies submitted by CAISO and SCE in the LTPP proceeding highlight the potential for significant curtailment in 2024 if the RPS increased to 40% without any other policy changes. CAISO studies projected about 400 GWh of curtailment in 2024, whereas SCE studies projected about 900 GWh. The results highlight the large uncertainties in the outcomes, likely dependent upon the study's assumptions and modeling methods.

Furthermore, solar is expected to make up 45% of renewables by 2030 under a 50% renewables scenario,[31] assuming other procurement policies remain the same, which may not be ideal to meet the evolving needs of the grid. The expected ratio of solar/wind added to the grid in the next few years results from the *least-cost, best-fit* (LCBF) procurement methodology used by the IOUs. In the past LCBF has led to more wind procurement, but given that most high quality and easily developable wind sites in California have been used, this trend is not expected to continue. If renewable mix of an increased RPS continues to tip towards solar, curtailment could be a bigger issue. The opposite is also true: if the renewable mix changed, curtailments might be less frequent, but different issues could emerge. Although the RPS proceeding is considering LCBF changes (discussed in Chapter III), it will take a few years to create new policies, so some amount of solar development is already in the pipeline and likely to come to fruition regardless of modifications to procurement rules. Therefore, solar curtailment continuing to increase in the near term is inevitable. LTPP and RPS modeling is discussed in further detail in Chapter III.

5. Cost-Effectiveness of Curtailment

Mitigating over-supply conditions by curtailing renewable generation may be acceptable in moderate amounts and may not result in significant costs to ratepayers. However, larger amounts of curtailment that occur on a regular basis may not be desirable because curtailment wastes renewable energy, thus undermining achievement of California's RPS targets and GHG reduction goals. Curtailment may also be an uneconomic way to plan and operate the grid and may impose excess costs on ratepayers, because if curtailment exceeds the amounts allowed by contract terms, the generator is still paid for the energy that is curtailed (i.e. not produced) as if it was delivered. Also, financing for renewable projects is commonly based on actual output and the related tax incentives, so curtailment may be problematic in the long-term.

Nevertheless, curtailment may continue to be an economically efficient solution in the near future if the overall quantity of curtailment is within a few percent of total RPS eligible generation. Indeed, economic curtailment can occur as needed through the market price, and it does not require investment in permanent resources. However, given that curtailing RPS resources is inherently counter-productive to meeting RPS and

[30] Thus far, the v6.0 calculator has modeled 30 different scenarios.

[31] E3, 2014, "Investigating a Higher Renewables Portfolio Standard in California," January, *available at*: www.ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf.

GHG goals, increasing curtailment is unlikely to be the most preferred option in the long-term. CPUC Staff has begun to analyze what levels of curtailment in 2020 could result in little or no cost to ratepayers.

California in International Context: Other countries with high shares of renewables, such as Germany and Denmark, are facing very low projected curtailment levels and costs, and these countries continue to be primarily concerned with wind-power curtailment. The significant predicted curtailment of solar, and the challenges this poses, so far appear to be rather unique to California amongst electric grids worldwide. (See Appendix A.)

D. Signpost of Reliability: Need for Ancillary Services

The traditional utility model, as discussed above, provided grid operators with the ability to commit and to dispatch (to start up and to specify desired output levels for) system resources to serve fluctuating energy loads while also being positioned to respond to changing and sometimes unexpected conditions. However, to ensure that they can respond to conditions such as generator or transmission outages, grid operators also rely on additional tools generally called ancillary services.[32] Ancillary services, so-called because they are services in addition to the provision of energy to meet load, are generally provided by natural gas power plants and hydropower in California today. These resources have high controllability including ability to ramp their output up and down rapidly and also to start and stop with relatively high frequency.[33]

The different types of ancillary services needed by grid operators typically include the following: load-following, regulation (up and down), contingency reserves (spin and non-spin), frequency response, reactive power (voltage support), and "black start."[34] CAISO currently operates ancillary services markets only for regulation (up and down separately) and for contingency reserves.[35] The other services are provided by generators without a comprehensive market framework for procurement and compensation. CAISO is currently considering market frameworks for the provision of and compensation for reactive power (for voltage support), frequency response, and a *flexible ramping product* (which is similar to load following and discussed in Chapter III).[36]

As already discussed, wind and solar are variable and generally less controllable and predictable than conventional generation (such as gas-fired and hydro generation). Therefore, increasing penetration of wind and solar creates an increased need for ancillary services to respond to fluctuations and uncertainties. At the same time, wind and solar generators are less able to provide ancillary services than conventional generators,

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[32] Ancillary services refer to "those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system." *See* FERC's online glossary*, available at*: www.ferc.gov/market-oversight/guide/glossary.asp.

[33] To provide ancillary services, natural gas plants must be online, which means they are emitting GHGs even when they are not necessarily needed to provide energy to meet load.

[34] "Black start" is the ability of a generating unit to go from a shutdown condition to an operating condition, and start delivering power without assistance from a power system.

[35] Generally, it is assumed that a contract (power purchase agreement) compensates a generator for these services where there is not a separate market mechanism.

[36] For information about reactive power, *see*: www.caiso.com/informed/Pages/StakeholderProcesses/ReactivePowerRequirements-FinancialCompensation.aspx; for information about frequency response, *see*: www.caiso.com/informed/Pages/StakeholderProcesses/FrequencyResponse.aspx

particularly under current designs and operations. Conventional sources will likely be needed to provide a substantial portion of ancillary services for the near future until new sources, such as advanced storage and DERs (including controllable demand response, *smart inverters*, and PEV charging) can provide these services.

Determining future ancillary services needs and the most reliable and economic means of meeting them is a critical part of planning for grid integration. Many studies are underway on a national level to understand and evaluate the ability of wind and solar resources to be designed and operated to provide ancillary services. One study recently conducted evaluates how the Texas *balancing area* (ERCOT) can integrate wind power by using synthetic (electronically emulated) inertia from this inverter-based generation to enable wind power to provide reactive power capabilities.[37] Other grid operators have also integrated ancillary services provided by wind into their markets.[38] At least two recently released studies for California also discuss the potential for wind and solar to provide regulating reserves (or "up-reserves") when there are over-generation conditions and they are curtailed.[39] In these studies, the need for ancillary services is linked to renewable curtailments. The need for load-following and regulation-down reserves currently necessitates the dispatch of conventional resources, thereby contributing to the need to curtail wind and solar resources.

CAISO markets for ancillary services have recently experienced scarcity events. CAISO triggered ancillary service scarcity pricing once in December 2014, February 2015 and April 2015, and twice in May 2015.[40] Four out of the five events were called in part or in whole for regulation-down scarcity in either or both the integrated forward market run and the 15-minute market run. One event in May was for both regulation-down and spinning reserves. The April event was the only regulation-up scarcity event. Most of the events were for a few intervals in a one- or two-hour period, but the second May event (May 24th) spanned an eight-hour period. CAISO predicts that in the near term, there may continue to be scarcity events for ancillary services. Further analysis of the ability of renewables to provide ancillary services is needed, and this analysis will be discussed further in Chapter IV.

E. Conclusion

With a status-quo grid, California will likely achieve a 33% RPS without major reliability implications. However, the state cannot achieve the Governor's new GHG goals, and is unlikely to cost-effectively integrate the renewables necessary to reach a 50% renewable target, without further transformation of the electric grid.

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[37] J. Weiss and B. Tsuchida, 2015, "Integrating Renewable Energy into the Electricity Grid: Case studies showing how system operators are maintaining reliability," prepared for Advanced Energy Economy Institute, June.

[38] *Ibid*.

[39] J.H. Nelson and L.M. Wisland, 2015, "Achieving 50 Percent Renewable Electricity in California: The Role of Non-Fossil Flexibility in a Cleaner Electricity Grid," Union of Concerned Scientists; *see also*: D. Lew, M. Schroder, N. Miller, and M. Lecar, 2015, "Integrating Higher Levels of Variable Energy Resources in California," GE Energy Consulting, Prepared for Large-scale Solar Association..

[40] *See* "CAISO market notices," *available at*: www.caiso.com/informed/Pages/Notifications/MarketNotices/Default.aspx.

III. Current Actions to Address Grid Integration

What is California doing currently to assist the integration of increasing renewables on the grid? What responses are already underway?

In recent years, California has implemented many practices and policies that are assisting grid integration and will continue to do so as California reaches a 33% RPS by 2020. These practices and policies are distributed across a wide array of CPUC proceedings and CAISO initiatives, and involve three primary institutions (CPUC, CEC, and CAISO).

A. Flexibility and Grid Integration in Long-Term Procurement Planning

The Long-Term Procurement Plan (LTPP) proceeding and framework is currently the "home" for most of the analysis and planning related to flexibility and grid integration at the CPUC. Through the LTPP, the CPUC determines whether existing resource are sufficient to meet future reliability needs and authorizes the plans of utilities for procuring or building new capacity over the next ten years. The LTPP framework specifically examines reliability in the context of ensuring resource sufficiency for the overall system, transmission constrained (local) areas, and *operational flexibility*. Analysis in the LTPP incorporates a number of variables including forecasts of load, DG, storage, energy efficiency, demand response, combined heat and power, resource retirements, as well as the flexibility of generation. The scope of the LTPP has evolved in a number of ways in recent years to more directly address the grid integration challenge, for example, the proceeding has encouraged the development of stochastic modeling techniques to better understand the probabilities of forecasts. Stochastic modeling may be better suited than deterministic modeling to understanding some of the key factors related to integrating a high level of renewables onto the grid, because stochastic modeling can capture grid reliability and flexibility issues during non-peak periods and under a range of renewable resource conditions.[41]

Most recently, the 2014 LTPP (R.13-12-010) directed technical studies to assess whether additional flexible resources would be needed to ensure system reliability through 2024. The modeling conducted by parties since this ruling has been responsive to grid-integration concerns, although preliminary study results appear to conclude that no new procurement for flexible resources is required at this time, while recognizing that the current models need improvement. A ruling issued in March 2015 directed the LTPP proceeding to begin a new phase,[42] which focuses on validating the parties' modeling results and investigating efficient solutions to potential operational flexibility concerns such as over-generation.[43] This new phase (Phase 1b) is addressing a number of issues related to operational flexibility, such as the implications of constraining

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[41] Whereas deterministic modeling only considers one fixed set of future conditions, stochastic modeling models a wide variety of conditions establishing probabilities and reliability risk. In conducting long-term stochastic modeling, California is one of the early global leaders. For more background on both deterministic and stochastic modeling, refer to the "Collaborative Review of Planning Models," *available at*: www.cpuc.ca.gov/NR/rdonlyres/ECE43E97-26E4-45B7-AAF9-1F17B7B77BCE/0/CombinedLongTermProcure2014OIR_Report_CollaborativeReview.pdf.

[42] Ruling issued on March 25th into R.13-12-010.

[43] For more information on Phase 1b, *see* "Long-Term Procurement Plan History," *available at*: www.cpuc.ca.gov/PUC/energy/procurement/LTPP/ltpp_history.htm.

renewable curtailment. It is also focused on validating and improving modeling methods and standardizing modeling output formats.[44] A separate ruling in the 2014 LTPP was aimed at developing a robust calculation method for a *renewable integration adder*, which would reflect the costs to the power system, and require a curtailment "cost curve" to be developed. The integration adder is further discussed below.

California in International Context. Current curtailment and over-generation experience from Germany, Spain, Italy, and other jurisdictions worldwide is relevant to California and the LTPP proceeding. So far, curtailment is minimal in most of these jurisdictions, but many strategies are emerging to address over-generation in the future. Notable is that these strategies are directly primarily at wind generation, while in California over-generation of solar may be of greater concern. (See Appendix A and references in Chapter II.)

B. Supply-Side Flexibility for Grid Integration

Initiatives and programs aimed at providing greater supply-side flexibility are underway in five main categories: (i) *flexible capacity*; (ii) market mechanisms, (iii) regionalization of energy markets, (iv) renewables procurement and valuation; and (v) energy storage.

1. Flexible Capacity: Flexible Resource Adequacy and CAISO Flexible Must-Offer Obligation

Flexible Resource Adequacy: The CPUC's Resource Adequacy (RA) regulatory framework ensures that the IOUs have procured adequate generation capacity to meet 115% of peak demand. The CPUC-jurisdictional *load-serving entities* (LSEs)[45] must show, on both a monthly and annual basis, that they have sufficient generation resources to meet the needs of the power system. In 2011, the RA regulatory framework was modified to go beyond system and local RA to account for "flexible capacity need."[46] This was done in response to changing grid conditions, especially increased renewables and related need for ramping. This was the first time that the CPUC explicitly recognized that flexible resources were something that should be defined and considered in a special way. RA flexible capacity targets were first implemented for the 2014 RA year.[47] In 2014, the CPUC developed and adopted interim counting rules, eligibility criteria, and *must-offer obligations* for preferred resources and energy storage, valid through 2017. The 2014 decision defines three different categories of flexible capacity: base flexibility, peak flexibility, and super-peak flexibility.[48] The also defines the calculation of

[44] Standardizing includes: developing common definitions, metrics, and standards for measuring system reliability.

[45] The CPUC jurisdictional LSEs are: PG&E, SDG&E, SCE, 3 Phases Renewables, Calpine, Commerce Energy, Commercial Energy of California, Constellation New Energy, Direct Energy, EDF Industrial Power Services, GEXA Energy California, Glacial Energy of California, Lancaster Choice Holdings, Liberty Power Holdings, Marin Energy Authority, Noble Americas Energy Solutions, Pilot Power Group, Shell Energy, Sonoma Clean Power, Tiger Natural Gas, and the UC Regents.

[46] "Flexible capacity need" was defined as "the quantity of resources needed by the ISO to manage grid reliability during the greatest three-hour continuous ramp in each month." Resources will be considered "flexible capacity" if they can sustain or increase output, or reduce ramping needs, during the hours of the ramping period of "flexible need" (R.11-10-023, D.13-06-024). *See also* CPUC, 2014, "Joint Reliability Plan: Track One Staff Report," October, *available at*: www.cpuc.ca.gov/NR/rdonlyres/DBE8AA4B-EED7-4650-A87B-1A519AF54A2C/0/JRPStaffReportFinal_share.pdf.

[47] D.13-06-024.

[48] D.14-06-050. "Base flexibility" is the capacity needed to handle the largest 3-hour secondary ramp that occurs anytime during a one-month period. "Peak flexibility" is the additional capacity needed, in addition to "base flexibility" capacity, to handle the largest 3-hour primary ramp anytime during a one-month period. "Super-peak flexibility" is the additional capacity needed to handle the final 5% of the largest 3-hour primary ramp anytime during a one-month period. Thus, "base flexibility" and "peak flexibility" together allow

effective flexible capacity based on the ability of a resource to meet and sustain a three hour ramp, with various other caveats and allowances for *non-generating resources* such as demand response and storage.[49]

Starting in 2014, the LSEs were required to ensure sufficient flexible capacity in these three categories on a monthly and annual basis as part of their RA compliance. The specific amount of flexible capacity need to be allocated among the LSEs is determined through an annual flexible capacity needs assessment conducted by CAISO and is based on the largest 3-hour ramp predicted for each month of the year. Flexible capacity needs assessments were first published in 2014,[50] and 2015 is the first compliance year for the IOUs to demonstrate that they have procured sufficient flexible capacity. When the CPUC adopted these requirements and the current definition of "flexible capacity," it acknowledged these requirements were "interim" and therefore the CPUC is expected to assess, through the RA proceeding, and in coordination with CAISO, whether the requirements should be revised by 2018 to be more effective at addressing grid integration needs. In adopting the flexible RA requirements, the CPUC also acknowledged the need to balance the assurance that specific identified future capacity needs are met, with creating a compliance program that is not so complex that it is infeasible to implement.[51]

CAISO's Flexible RA Must-Offer Obligation Requirements: Must-offer obligations bind RA generators to making themselves available to the CAISO through bids or "self-schedules." In 2014, CAISO filed, and FERC subsequently approved, tariff revisions to implement the Flexible Resource Adequacy Must-Offer Obligation (FRAC-MOO).[52] FRAC-MOO requires that generators designated as flexible RA make their flexible capacity available as one of three types of must-offer obligations in the day-ahead and real-time energy market (not through self-scheduling). Although the FRAC-MOO tariff requirements have been in place less than a year, CAISO plans to assess the effectiveness of the current requirements and to consider revising them for implementation as soon as 2017, and has begun a new stakeholder initiative to this effect.[53] Through this initiative, CAISO has also committed to considering how flexible capacity can be provided by imported resources, and to determining flexible capacity counting rules for storage and demand response.[54]

2. New Market Mechanism: Flexible Ramping Product

Since 2011, CAISO has been developing a new flexible ramping product ("Flexiramp") to aid in the availability of flexible resources to support upward and downward ramping. After an extensive stakeholder

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meeting the largest ramp during the month. Technically speaking, "base flexibility" plus "peak flexibility" are defined as 95% of this largest ramp of the month.

[49] D.14-06-050.

[50] CAISO, 2015, "Final Flexible Capacity Needs Assessment for 2016," *available at* www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2016.pdf.

[51] *See* D.14-06-050.

[52] FRAC-MOO tariff provisions established: (1) a methodology for determining flexible capacity needs and allocating among California's regulatory authorities; (2) rules for assessing the system-wide adequacy of flexible capacity showings; (3) backstop procurement authority to address system-wide deficiencies of flexible capacity; and (4) must-off obligations as part of its normal market operations.

[53] *See* CAISO, FRAC-MOO 2 stakeholder initiative working group presentations, *available at* www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx.

[54] *See* "Reliability Services," *available at*: www.caiso.com/informed/Pages/StakeholderProcesses/ReliabilityServices.aspx.

process, CAISO is expected to begin offering this product in the wholesale market before the end of 2016. The basic goal of Flexiramp is to shift generation in small increments of time away from low-ramp periods and to high-ramp periods.

Flexiramp allows the CAISO market to pay generators their opportunity cost some of their capacity to remain on standby during low-ramp periods, so that the generator is then available to turn on during high-ramp periods at the request (dispatch) of CAISO, thus potentially supporting integration. Generators receive compensation for the opportunity costs (equal to the market price) of not selling energy during the period when the resource remained "off," plus the market price if and when they do provide energy later. The flexible generation "market" actually takes place within 15- and 5-minute intervals, as CAISO determines during those intervals whether it needs more or less ramping than was dispatched at the start of each interval. Flexiramp is designed to allow all types of generators to participate, including wind and solar, and also non-generating resources like storage.[55]

California in International Context. Flexible generation capacity and new or more effective market mechanisms, including regionalization, are emerging as cornerstones of grid integration strategies in other jurisdictions worldwide. (See Appendix A.) However, supply-side storage is still a very nascent strategy in jurisdictions facing high shares of renewables in the future, with some jurisdictions now viewing storage as only a long-term solution. For example, many in Germany no longer see the need for storage in the short to medium term, given other flexibility options.[56]

3. Regionalization of Energy Markets and Balancing Areas

CAISO's market systems automatically balance supply and demand for electricity every fifteen minutes, dispatching the least-cost resources every 5-minutes. In November, 2014 CAISO began implementing a regional Energy Imbalance Market (EIM) that allows participation of other neighboring *balancing authorities* in the real-time (15- and 5-minute) market as a way to share reserves and integrate renewable resources across a larger geographic region.[57] Currently, PacifiCorp is participating in the EIM for all of its service territory. CAISO is in planning stages to expand the EIM to NV Energy, Arizona Public Service, and Puget Sound Energy. The full implementation of the EIM is expected to mitigate over-generation events and potentially reduce curtailments in California and neighboring balancing areas.

A longer-term vision for regionalization also includes day-ahead scheduling coordination within a combined balancing area. PacifiCorp and CAISO are also considering a full integration of their balancing areas, and are exploring the feasibility, costs and benefits of PacifiCorp becoming a fully participating transmission owner on a day-ahead basis like a California IOU, including sharing costs (grid management charges and

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[55] Generators that are flexible RA resources subject to FRAC-MOO will also be subject to a subset of those requirements under Flexiramp, and thus Flexiramp is a combination of market mechanism and must-offer obligation (mandate). For example, in the day-ahead market, a 300 MW gas plant might be required to offer 100 MW into the day-ahead market as base, peak, or super-peak flexibility. Under Flexiramp, that same obligation would apply, but for a smaller amount of capacity. So the 300-MW gas plant might be required to bid 50 MW of capacity in the day-ahead market under Flexiramp.

[56] *See* Agora Energiewende, 2015, and Miller et al., 2015, in Appendix B.

[57] For complete information about the EIM and ongoing stakeholder initiatives related to the EIM, *see*: www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarketFoundation.aspx.

transmission access charges).[58] If neighboring balancing authorities ("out of state parties") become integrated with CAISO, their participation in the day-ahead market likely poses significant potential to increase flexibility and grid integration for California. However, many governance and political hurdles will need to be overcome before this integration could become a reality, and CAISO would conduct a full stakeholder and regulatory process before further implementation.

4. Adjusting the Value of Renewables in Procurement

Least-Cost, Best-Fit Reform: The RPS proceedings have established a least-cost, best-fit (LCBF) evaluation framework for how IOUs compare the value of different renewable resources in the procurement process. The framework was designed to balance ratepayers' interests in minimizing the nominal cost of a renewable energy contract ("least-cost") with the value that the resource can provide within the context of the system in which it will be operating ("best-fit"). Currently, the least-cost methodologies used by IOUs, which determine a resource's net-market value, do not fully account for the relative impact that different renewable resources may have on grid reliability. For example, grid integration costs related to the needs for additional system flexibility and ancillary services at high RPS penetration have not been fully studied and determined.

The CPUC recently began LCBF reform by adopting generic (not California-specific) renewable integration cost[59] adders for wind and solar resources in the utilities' 2014 RPS Procurement Plans. The integration adders reduce the net-market value of wind and solar resources relative to non-variable renewable resources, changing how utilities rank bids during bid evaluation. In parallel, SCE was directed[60] via a ruling to model the California-specific integration costs related to increased need for ancillary services. The results are being considered in the LTPP proceedings.[61] If adopted, the CA-specific integration adders will replace the generic interim adders.

Improved procurement valuations of variable renewable resources can lead to a mix of renewables that requires fewer grid integration services. Therefore, the adder could result in a different mix of renewables that lessens the grid integration needs created by an increased RPS. In some respects, CPUC's current work to reform LCBF is closing the conceptual distance between "least-cost" and "best-fit" by better reflecting the fit of the resource within the system as a whole. Similarly, ongoing revisions to the methodology used to value renewables' capacity contributions (discussed below) will bring an additional aspect of how the resource fits into the system as a whole into its net market value.

Changing Renewables' Capacity Value: The methodology for determining the capacity value of a renewable resource for RA and RPS procurement purposes is also changing. CPUC Staff recently released an initial

[58] Detailed information about the consideration of a regional energy market and the MOU between CAISO and PacifiCorp is *available at*: www.caiso.com/informed/Pages/BenefitsofaRegionalEnergyMarket.aspx#PacifiCorp.

[59] "The term renewable integration cost does not have a single standard or uniform definition, and depending on the usage may be used to describe costs associated with: holding increased load-following and regulation operating reserves to balance renewable forecast error and sub-hourly variability; meeting hour-to-hour and multi-hour ramps in net load; impacts associated with increased starts and cycling of flexible resources; curtailing renewable resources; procuring or investing in flexible generation capacity to facilitate reliable operations; and with costs of ancillary service capacity." Excerpt from SCE filing, *available at*: docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=152483173.

[60] R.13-12-010.

[61] *See* report filed by SCE, *available at*: docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=152483173.

proposal for the "effective load carrying capability" (ELCC) methodology in the RA proceeding.[62] Pursuant to a statutory requirement,[63] the current method of valuing wind and solar resources' capacity value will be replaced with an ELCC method. ELCC considers both system reliability needs and facility performance, and reflects not just the output capabilities of a facility but also the usefulness of this output in meeting overall electric system reliability needs. This will change the way that RPS resources are valued in meeting RA obligations and thus will likely lead to changes to the mixture of renewable resource types, and therefore may have positive impacts on future flexibility needs.[64]

Separately, Staff issued a proposal in the RPS proceeding recommending that the IOUs develop and standardize an ELCC methodology to use in their LCBF evaluations of future RPS solicitations.[65] This will require developing marginal ELCC values with a 20-year outlook (as opposed to 2-3 years forward, which is the focus of the ELCC work under the RA proceeding). [66] The proposal includes guidelines for identifying and developing common methodologies, inputs, and assumptions that can be used across ELCC value calculations.[67]

Storage Procurement and Roadmap. Assembly Bill 2514 directed the CPUC to determine appropriate storage procurement targets for each LSE and to consider policies to encourage deployment of energy storage.[68] CPUC decisions implementing this bill created a storage framework and established a target for each LSE to procure viable and cost-effective thermal energy storage by the end of years 2015 and 2020.[69] These targets total 1.325 GW of storage procurement by the end of 2020 across three grid domains: transmission, distribution, and *customer-side*.[70] The targets require that all installations occur no later than 2024.[71] The first procurement cycle (2014-2016) is underway and the resulting storage contracts will be submitted for CPUC approval in December 2015. Under the Storage Framework, projects must address at least one of three policy objectives: (1) Integration of renewable energy sources; (2) Grid optimization, including peak load reduction, reliability needs, or deferment of transmission and distribution upgrades; or (3) Reduction of GHG emissions. Through the active

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[62] CPUC, 2015, "Probabilistic Reliability Modeling Inputs and Assumptions," July 15th, *available at*: www.cpuc.ca.gov/NR/rdonlyres/54510A14-B894-4E05-A933-3665DA72F060/0/ProbabilisticReliabilityModelingInputsandAssumptionsPartTwo.pdf.

[63] Pub. Util. Code § 399.14 *et seq.*

[64] The "exceedance method"is currently used to calculate capacity values, and reflects mostly on the facility's historical production at system peak. ELCC values are being determined based on stochastic modeling using the SERVM modeling tool. SERVM calculates numerous cost and reliability metrics for a given study year as a function of weather conditions, overall economic growth, and unit performance. *See* Staff Paper for further detail.

[65] *See* "Ruling of Assigned Administrative Law Judge Accepting into the Record Energy Division Staff Paper on the Use of Effective Load Carrying Capability for Renewables Portfolio Standard Procurement and Requesting Comment," *available at*: docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K691/154691996.PDF.

[66] "Once implemented, multi-year marginal ELCC values will be applied to the facility's maximum output in order to determine a new RPS resource's RA value in RPS procurement and the RPS calculator.

[67] "LCBF requires multi-year ELCC values [and] . . . should have a long term (20-year) focus due to the duration of RPS contracts while RA ELCC value only covers 1-3 years . . . RA ELCC values do not require distinctions between technology types and locations which are important factors for LCBF valuation." *Id.*

[68] *See* "Energy Storage," *available at*: www.cpuc.ca.gov/PUC/energy/storage.htm.

[69] D.13-10-040.

[70] Note: the distinction created by these targets between "distribution" and "customer-side" is inconsistent with how the terms "distribution" and "distributed" are used in this paper.

[71] The decision also requires LSEs, such as CCAs and ESPs to procure energy storage equal to 1% of their annual 2020 peak load by 2020 with installation no later than 2024.

proceeding, R.15-03-011, storage policies are being refined and program details are being developed to consider how storage can contribute to flexible needs for grid integration.

As a compliment to CPUC efforts, in December 2014, the CPUC, CEC and CAISO jointly published an energy storage roadmap.[72] This roadmap was developed through a multi-agency approach and extensive stakeholder consultations. The roadmap lays out priority actions for planning, procurement, rate design, interconnection, and market participation, and assigns actions to each of the three agencies.

C. Distributed Energy Resource Flexibility for Grid Integration

Various statewide proceedings, initiatives, and programs are in place to support energy-resource measures at the distribution level (i.e. not directly interconnected to the transmission grid). Many of these measures can increase the flexibility of distributed energy resources, thereby supporting grid integration. This paper uses the term "distributed energy resources" (DERs) rather than "demand-side resources" to reflect the shrinking distinction between "supply-side" and "demand-side/ load-modifying" programs at the CPUC. The Integrated Distributed Energy Resources (IDER) proceeding (R.14-10-003) is specifically aimed at bridging this divide.[73]

California in International Context. California is among the first jurisdictions worldwide to pioneer many of the demand-side flexibility options for grid integration discussed here. In particular, demand response for flexibility purposes, time-of-use and dynamic rates, distributed storage, and smart inverters are nascent or not-yet-emerging strategies in jurisdictions that are leading the way with high shares of renewables, such as Germany, Denmark, Spain, Ireland, and China. Thermal storage coupled with flexible combined heat and power (CHP) plants is one of Denmark's core demand-side flexibility measures, which has no real analog yet in California. (See Appendix A.)

1. Designing Effective Retail Rates, Tariffs, and Incentivizing PEVs

TOU and Dynamic Rates. Rate design, including *time-of-use* (TOU) and *dynamic rates*, has an important role in assisting grid integration because it can lead to loads that are better aligned with solar generation. New residential TOU rates are being considered, piloted, and designed to do the following: (1) Reduce over-supply by incentivizing more demand in mid-day hours when solar generation is greatest; and (2) reduce ramping capacity needs (magnitudes) by creating economic signals for demand-side load reduction during periods of upward-ramping, and demand-side load increases during periods of rapid downward-ramping.

TOU pricing is already in place for non-residential load, with recent TOU rates mandatory for small and medium commercial and industrial customers, beginning in 2012. However, existing commercial TOU rates were not designed around integrating renewables. A process leading to residential TOU pricing was adopted by

[72] CAISO, 2014, "Advancing and Maximizing the Value of Energy Storage Technology: A California Roadmap," December, *available at*: www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf.

[73] D.15-09-022.

the CPUC in July 2015.[74] This decision will set in motion a series of residential TOU pilots leading to the implementation of default residential TOU by 2019.

Each of the IOUs has proposed changes to their peak TOU periods to provide better alignment with hours of high net loads and high wholesale energy prices.[75] Each of their proposals call for a shift in peak TOU periods to later in the day (e.g., 4-9 pm), which aligns with expected peak or "super-peak" periods. However, CAISO has noted in public proceedings that the IOUs proposed changes do not fully address expected changes to the California electric grid, because the accelerated growth in solar generation has already resulted in traditionally accepted TOU periods becoming increasingly misaligned with energy demand and cost.[76] In contrast, dynamic rates, which involve smaller time intervals, and properly grid-aligned TOU periods can shift peak load demand, incentivize energy consumption during low-demand periods to minimize over-generation, and reduce the need for flexible capacity resources.[77]

Cost-based TOU rates may also be a factor in incentivizing solar customers to co-install storage. These rates are being reviewed and piloted in the residential rate reform proceeding (R.12-06-013). Non-residential customer adoption of solar, storage, and EVs is also influencing rate design elements, such as TOU and demand charges. These are addressed in other rate-design proceedings and through general rate cases.

Net Energy Metering Enhancements. TOU and dynamic rates can affect customer decisions about installing DERs, and the CPUC is scheduled to adopt a NEM successor tariff to take effect by July 2017. Under the ongoing NEM successor tariff proceeding,[78] parties to the proceeding have proposed various compensation and rate structures (including TOU). These structures could incentivize system configurations that facilitate integration of customer-side renewable DG onto the grid, including west-facing solar systems, solar-plus-storage systems, and aggregated resources that can be dispatchable in wholesale markets. The CPUC is required to adopt a NEM successor tariff by the end of 2015.

Vehicle-Grid Integration. Through the Alternative Fuel Vehicles (AFV) proceeding,[79] the CPUC is considering how to define a PEV resource, the role of utilities and third party aggregators in providing grid services, and how to capture and return the value of providing grid services to customers and PEV drivers. In coordination with this proceeding, CPUC Staff published a white paper on *vehicle-grid integration* (VGI),[80] which proposed to harness the usage characteristics and technology capabilities of PEVs as a grid integration asset.

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[74] D.15-07-001.

[75] SCE: proposed in A.13-12-015 and adopted in D.14-12-048. SDG&E: proposed in A.14-01-027 and denied without prejudice in D.15-08-040 (may be resubmitted in A.15-04-012). PG&E: proposed in A.14-11-014, settlement pending.

[76] *See* CAISO, 2014, "Multi-Agency Update on VGI Research," Presentation to California Energy Commission, November 19, *available at*: www.energy.ca.gov/research/notices/2014-11-19_workshop/presentations/CAISO_ISO_Multi_Agency_EV_Update_2014-11-19.pdf.

[77] Adapted from CAISO, 2015, "CAISO's TOU period analysis to address 'High Renewable' grid needs," Presentation to California stakeholders, March 12, *available at*: www.caiso.com/Documents/CaliforniaISO_Time_UsePeriodAnalysis.pdf.

[78] R.14-07-002

[79] R.13-11-007.

[80] CPUC, 2014, "Vehicle - Grid Integration," March, *available at*: www.cpuc.ca.gov/NR/rdonlyres/5052DF0E-950C-4CF6-A4E0-A691DBD64C8E/0/CPUCEnergyDivisionVehicleGridIntegrationZEVSummit.pdf.

Rate design for PEVs can play a unique role in grid integration, as recognized by SB 350: "[d]eploying electric vehicles should assist in grid management, integrating generation from eligible renewable energy resources."[81] The VGI white paper recognizes that PEV batteries, while primarily used for personal mobility, can be more fully utilized as storage to provide grid services.[82] Staff envisions use-cases in which PEVs would have the capability to: modulate charging levels, discharge power onto the grid, co-optimize drivers' mobility needs with the grid's needs, and have their capacity aggregated in fleets of mobile energy resources.

The VGI Roadmap,[83] currently being implemented by CPUC, CEC, and CAISO staff is expected to determine how price-based incentives for PEV charging could absorb over-generation. The three agencies released the roadmap in February 2014, pursuant to the Governor's 2012 Executive Order on Zero Emission Vehicles (ZEV),[84] which calls for 1.5 million ZEVs on state roadways by 2025 and 80% reductions in GHG emissions from the transportation sector by 2050. The Roadmap identified three pre-requisites before PEVs can be used to integrate renewable energy. First, the grid impacts of PEVs must be modeled, which requires understanding their likely market share and adoption rate. Next, the CPUC could define procurement policies and create IOU incentives for PEV purchase. In the third phase, automakers would be able to incorporate capabilities like communications and bidirectional charge controllers in to their vehicles to enable them to communicate with the grid.

As a major first step in implementation of the roadmap, each of the IOUs has filed applications with the CPUC that include approximately $1.1 billion in total costs to install, own, and operate (to varying extents) PEV charging infrastructure[85] that could facilitate additional vehicle load. These proposals represent between one-fifth and one-third of the charging infrastructure needed to serve the 1.5-million ZEV goal per a statewide assessment conducted by the National Renewable Energy Laboratory. The impressive industry response to the VGI whitepaper and Roadmap highlights the need for the CPUC to coordinate interagency efforts on VGI.

2. Integrating, Optimizing, and Interconnecting Distributed Energy Resources

Integrated Distributed Energy Resources. The CPUC recently expanded the scope of the Integrated Distributed Energy Resources (IDER) proceeding (R.14-10-003) to focus on collective actions to optimize distributed energy resources, based on the impact and interaction of such resources on the system as a whole, as well as on a customer's energy usage. The IDER proceeding (formerly IDSR) will develop a regulatory framework that enables customers to effectively and efficiently choose from an array of demand-side and DERs. Phase One of the proceeding (expected to conclude in the next two years) will begin to develop this framework through relevant technology-agnostic valuation methods and "sourcing" mechanisms.[86] Policies on localized incentives

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[81] Pub. Util. Code § 740.12

[82] For example, the Storage Procurement Framework Decision 13-10-040 Conclusion of Law 35 found that electric vehicles providing Vehicle to Grid (V2G) services qualified as customer-side storage.

[83] CAISO, 2014, "California Vehicle-Grid Integration (VGI) Roadmap: Enabling vehicle-based grid services," February, *available at*: www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf.

[84] *See* www.gov.ca.gov/news.php?id=17463.

[85] SDG&E A.14-04-014, SCE A.14-10-014, and PG&E A.15-02-009.

[86] Sourcing mechanisms may include pricing (rates), tariffs, contracts, procurement, market mechanism, or other strategies to deploy DERs where and when needed.

and consistency across demand-side cost-effectiveness methods are expected to be developed in parallel as part of Phase One.

The IDER proceeding will be closely coordinated with the Distributed Resources Plan (DRP) proceeding (R.14-08-013). It is expected that the IDER proceeding will create the framework to determine how to source the DERs that would fit the needs and characteristics of the distribution system identified in the DRP proceeding. It is also expected that the IDER proceeding will implement the "tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources," after they are identified and proposed in the DRP proceeding, in accordance with Public Utilities Code Section 769(b)(2).

Demand Response. Virtually all demand response in California to date has been procured through IOU demand-side programs. In 2014, LSEs invested slightly more than $300 million of ratepayer funds in demand response. Most demand response investment has focused on reducing peak load, rather than on providing additional system flexibility (for example, handling ramping or over-generation). However, this is changing. One of the major decisions made in the current demand response proceeding[87] in 2014 was to bifurcate demand response resources into *supply-side resources*, which can be integrated into CAISO's wholesale market, and demand-side (load-modifying) resources. Demand response capacity is now being offered into CAISO's wholesale energy market through various "products," which include proxy demand response and reliability demand response. To make this possible, the RA program has adopted specific effective flexible capacity and qualifying capacity rules for demand response. Once fully integrated into CAISO's markets, supply-side demand response resources will be able to provide flexible ramping capacity to the grid. However, this complete integration is highly dependent upon the CAISO and CPUC removing barriers and adjusting rules in order to accommodate a larger penetration of demand response in general.

The concept of enabling demand response resources in retail and wholesale markets to "go in reverse" (to stimulate increased consumption during times of excess solar generation) is key to grid integration. A variety of initiatives and pilots are already underway at both CPUC and CAISO that aim to determine how this can be done and how customers can be appropriately compensated for grid integration services they provide. The CAISO has scoped this issue into the second phase of its Energy Storage and Distributed Energy Resources (ESDER) initiative stakeholder process. The CPUC authorized and sought stakeholder input on a proposed PG&E pilot to test supply-side demand response products that may be able to provide a flexible ramping product to help with grid integration.[88]

The CPUC also commissioned a demand response "Potential Study," which will assess the potential for emerging products, such as reverse demand response, to absorb excess generation and flatten afternoon ramping needs. This study builds upon CAISO's roadmap,[89] which focuses on the objective of "planning for increased reliance on distributed resources to meet grid needs." The Potential Study will also look comprehensively at the technical potential of residential, commercial, and industrial end users to provide

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[87] R.13-09-011.

[88] D.14-05-025, p. 22 and OP 6(f).

[89] The roadmap serves as a coordinating document between CAISO, the CPUC and the CEC, to create and adjust rules and programs as appropriate in each agency's programs and proceedings. It states that "demand response resources will contribute to the low-carbon flexible capacity needed to maintain real-time system balance and reliability while also supporting the integration of increasing levels of renewable energy resources." Implementation of the roadmap is ongoing.

demand response, and the economic and market potential of demand response products. The analysis will include evaluating the capabilities of end-use loads to shift, shed, or take electricity use, and will emphasize evaluating existing market products and how demand response fits into the wholesale market. The study is expected to be completed in two phases in 2016, and the results will be used to establish demand response goals in California.

Another demand response enhancement effort already showing promise is the improvement of the CPUC's Demand Response Cost-effectiveness Protocols,[90] which provide guidelines for the estimation of integration costs and benefits. A recently proposed update to the Protocols included a proposed "flexibility" adder. The exact definition and structure of the adder has not been determined, but it could increase the measured value of any demand response resource that can provide flexible capacity.

Distributed Storage Incentives and Interconnection: The CPUC's SGIP provides incentives to support existing, new, and emerging DERs. SGIP was expanded in 2008 to include customer-side energy storage, and CPUC staff is currently reviewing the SGIP rebates for all eligible technologies, including storage. The CPUC is also assessing the operational constraints and incentives affecting storage, including its role in assisting renewables integration. The introduction of storage as an addition to customer-side solar systems could help mitigate the predicted impacts of solar generation on the grid. With the program currently authorized to run through 2020, and with falling battery prices, substantial installation increases are expected.[91] The CPUC is currently establishing rules governing the ability of SGIP-funded storage to participate in Demand Response.[92] Most of these projects are expected to come from commercial, not residential, customers.

Stakeholder consultations on *Rule 21 Interconnection* for storage have led to some fundamental discussions on the role of these resources. Discharging is currently treated as generation under Rule 21, but stakeholders are currently considering whether storage should be treated as load, as generation, or both. The basic question stakeholders have focused on is: how should the interconnection screening by LSEs of non-exporting storage be treated for the "discharging" aspect of storage resources? These discussions are productively leading to further understanding of storage for both demand-side and supply-side flexibility.

CAISO Distributed Energy Resources Provider and DER Interconnection: CAISO recently created the Distributed Energy Resources Provider (DERP) category for participation in the wholesale market. This category allows for aggregation of DER sub-resources and streamlined metering and telemetry requirements. It was created in part because CAISO's current tariff does not offer a clear platform for smaller (i.e., < 0.5 MW) resources to participate in CAISO energy and ancillary services markets. The original DERP proposal was adopted by the CAISO board in June 2015,[93] but CAISO is continuing the stakeholder initiative to focus on removing barriers to small resource participation in CAISO markets and supporting emerging business models for DERs

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[90] *See* "Demand Response Cost-Effectiveness," *available at*: www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm.

[91] In 2014 SGIP enrolled 534 storage projects totaling 47 MW, and 329 projects were enrolled in 2015 totaling 65 MW. This is a dramatic increase from the prior four years (2010-2013), during which the program saw 437 total projects filed, equal to 23 MW.

[92] R.12-11-005.

[93] *See* CAISO initiative page: www.caiso.com/informed/Pages/StakeholderProcesses/ExpandingMetering-TelemetryOptions.aspx

interconnecting to the distribution grid.[94] As such, CAISO is proposing further tariff amendments to facilitate greater DER participation, and will seek board approval of the enhanced tariff amendments.

Smart Inverters: When installed alongside distributed solar resources, advanced or "smart" inverters have the potential to contribute to system-level flexibility, reliability, thus supporting grid integration. Smart inverters can sense real-time grid conditions and autonomously adjust or modulate DER power output to serve a localized grid balancing function. Smart inverters also have the ability to communicate with and respond to commands from a utility or DER aggregator to provide voltage and frequency support.

California is among the very first states to address standards and practices for smart inverters, which help mitigate the impacts of DERs at high local penetrations. Over the past few years, the CPUC has been working closely with utilities, inverter manufacturers, and DER developers to formalize rules for advanced or smart inverter functionality through a collaborative Smart Inverter Working Group (SIWG). Phase 1 of the SIWG resulted in the development of autonomous smart inverter functionality, adopted in D.14-12-035, requiring inverters to be able to, amongst other things, correct for deviations from nominal voltage or frequency and perform dynamic reactive power management. Phase 2 resulted in inverter communication protocols that are being incorporated into LSE interconnection handbooks and will be referenced in Rule 21. Phase 3 is proceeding to develop standards for even more advanced smart inverter functionality for potentially broader contributions to system flexibility.

D. Power System Dispatch and Control

A number of innovations in power system dispatch and control have greatly increased the ability of California's power system to integrate variable renewables. Two of the most significant follow:

Day-Ahead Renewables Output (Weather) Forecasting. The incorporation of advanced day-ahead weather forecasting into the operation of power system control and dispatch has become common and highly sophisticated in regions with high shares of renewables, such as California, Germany, and Spain. Such weather forecasting can be credited as a major contribution to our ability to integrate and balance high shares of renewables, because it makes variable renewables highly predictable for power system control and dispatch on a day-ahead basis. When forecasting does not match actual solar output, especially when output is over-forecasted, the energy market has responded with either real-time price spikes or negative pricing events, thus indicating the importance of accurate forecasting. California has also made great improvements in its modeling and forecasting of tomorrow's weather, to be able to predict variable solar and wind, and dispatch all resources appropriately in the day-ahead wholesale market.

Grid Reliability Calculations and Dispatch. California's power control and market operations have also evolved an advanced system for balance management and grid reliability. CAISO's power control center makes an updated forecast every 5 minutes for the upcoming 5-minute period. This rapid updating allows both the power control and energy market to quickly respond to changes in renewable output. And CAISO has greatly improved its daily *N-1 reliability calculations*, to make sure the lights stay on in the event of unexpected events or outages, even with variable renewables.

[94] *See* www.caiso.com/informed/Pages/StakeholderProcesses/ExpandingMetering-TelemetryOptions.aspx.

IV. Beyond Current Actions and Toward a Long-term Vision

Chapter III outlined actions that California's energy agencies are currently taking to address grid integration. This chapter goes beyond those actions to recommend short-term approaches in the form of "no regrets" policies that could be implemented by the CPUC through existing proceedings and programs. These actions would not require the level of analysis that Staff considers necessary to identify and prioritize longer-term solutions. Following the short-term approaches, this chapter then outlines a long-term vision for an integrated grid of the future, suggesting how the "Grid Integration Policy Pathway" can lead to solutions that provide needed flexibility while maintaining reliability.

A. Recommendations for Short-Term "No Regrets" Approaches

How can the CPUC, over the next few years, enhance the approaches to grid integration that have already been identified? Which additional short-term approaches are "no regrets" and are fairly well understood?

Staff recommends the following short-term approaches to enhancing existing CPUC programs and policies. Some of these approaches may be considered through an existing proceeding, either within the current scope of the proceeding or by modifying the scope. Many of these approaches require close collaboration with other agencies but could still be considered and implemented over the next few years.

1. Enhance Flexibility with Distributed Energy Resources: Time-of-Use Pricing, PEV Charging and Demand Response

Numerous approaches to the grid integration challenge come from CPUC programs related to DERs. Enhancing these programs in the short-term will ease the transition to a high-renewable energy future. Thoughtfully designed and coordinated sets of DER can mitigate the effects of the reliability signposts discussed in Chapter II.

Time-of-Use and Dynamic Pricing. The time is ripe for the CPUC to consider rate design issues holistically.[95] Recent CPUC decisions have identified improved retail rate design as a high priority for future action, but they have not laid out the specifics for what should be required of TOU rates to assist with grid integration. Also, if the CPUC were to undertake a comprehensive review of rate design issues, this could reveal opportunities to further optimize DER adoption to meet grid integration needs. As discussed in Chapter III, the primary flexibility needs that should be addressed through TOU pricing are diminishing the impact of the later evening peak and the mid-day periods of surplus renewables. In particular, CAISO has developed an informal proposal that would employ a four-season, four-time-period scheme to smooth and flatten the net-load curve by season.

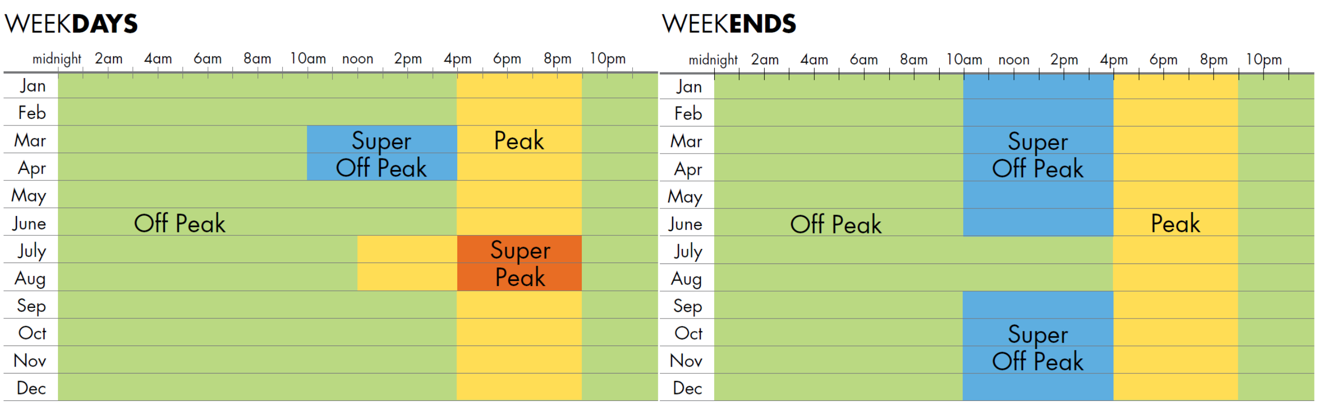
A holistic rate design review would allow the CPUC to implement TOU and dynamic rates for all customers that align with grid needs, and may incentivize customers to adopt different distributed solar and storage technology configurations. The CPUC's consideration of retail rate design could be organized into three

[95] The CPUC will consider opening a new OIR for TOU rate design issues, as per the draft OIR issued on 11/17/15. More details are not available given the timing of this publication.

tracks: 1) evaluating late-shift TOU periods as proposed by IOUs in pending *rate-design window* (RDW) cases; 2) assessing the results of a joint CEC-CPUC-CAISO TOU analysis in the 2015 Integrated Energy Policy report (IEPR) which, when released, will provide preliminary estimates of load responsiveness to grid-aligned TOU pricing; and 3) designing various TOU pilots to test TOU rate designs, such as ISO-proposed TOU periods. Staff has preliminarily concluded that an effective grid-aligned TOU rate design should, ideally, have very low super-off-peak rates during times of likely over-supply, and high rates in late afternoon and early evening peak hours. Important questions remain, however, regarding customer acceptance of such rates.

CAISO presented a proposal for a four-season, four-time-period scheme at a recent CPUC rate reform workshop (see Table 2).[96] Of special note, on weekends the hours of 10:00 AM to 4 PM are off-peak or "super-off-peak" except for the mid-summer months of July and August. The weekday hours of 4:00 PM to 9:00 PM are peak or "super-peak," reflecting the highest net loads.

Table 2. CAISO-Recommended TOU Periods



SOURCE: CAISO, March 2015, "CAISO's TOU period analysis to address 'High Renewable' grid needs."

These CAISO-recommended TOU periods could be considered either through existing CPUC rate design proceedings or a new rates proceeding. Whereas the rate reform proceeding provides a forum to pilot TOU periods for residential customers similar to CAISO's recommended structure, a procedural venue for piloting these exact recommendations, and for piloting non-residential TOU rate design, has yet to be confirmed.

Vehicle-Grid Integration. Rate design for PEV charging can play a unique role in grid integration to absorb over-generation during periods of peak solar or wind output. There are significant opportunities to advance VGI efforts by capitalizing on research being done at the state and national level. The CPUC can utilize lessons learned from current research, development and deployment (RD&D) projects on charging optimization controls[97] and communications protocols[98] to inform IOU deployment of PEV infrastructure networks. The U.S.

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[96] CAISO, 2015,"CAISO's proposed TOU periods to address grid needs with high renewables," presentation to R.12-06-013 workshop on November 17,2015, *available at*: http://www.cpuc.ca.gov/puc/ratedesignforums.

[97] For example, the charging optimization controls projects generally aim to determine how to meet certain constraints (adequately recharging the vehicle battery, dispatching power among arrays of vehicle chargers) while simultaneously minimizing costs (consuming during least expensive TOU periods, peak shaving to avoid demand charges) or maximizing value (consumption of renewable electricity).

[98] Communications protocols projects generally aim to develop methods for the secure and interoperable communication between different agents (drivers, manufacturers, facility operators, charging networks, utilities, and system operators) and infrastructure (vehicles, charging equipment, buildings, distribution/transmission control systems) to facilitate the use of PEVs for grid services.

Department of Energy is also doing significant research on power electronics, communications protocols, and is modeling integrated electricity and transportation systems.[99]

The CPUC should use current research and lessons learned from RD&D projects to inform rate development and planning activities for vehicle-grid integration. SB 350 requires the CPUC to direct the IOUs to propose multiyear programs and investments to accelerate widespread transportation electrification.[100] Through this oversight role, the CPUC should ensure that IOU deployment of PEV charging infrastructure leverages and returns ratepayer RD&D investments. This would mean that equipment installed can effectively maximize the use of zero-emission renewable electricity for charging (e.g., absorb over-supply), particularly in air quality management districts that require transportation to minimize fossil fuel emissions in order to meet Federal Clean Air Act mandates by 2023.[101] It is important for the CPUC to provide direction within its electricity regulations and markets early on in the deployment of infrastructure, given the timing required for automakers to design and manufacture "VGI-ready" vehicles.

Demand Response Enhancements. A number of barriers stand in the way of making demand response programs more effective at addressing grid integration; these include the immature stage of wholesale market integration, the lack of knowledge about how much flexible demand response potential exists, and untested program designs for demand response to provide flexible capacity. By enhancing CPUC policies and CAISO market structures to address these barriers, demand response can be transformed into a highly flexible generation and load-building resource.

Most immediately, the CPUC should continue to remove barriers to wholesale market integration of demand response through existing CPUC-managed working groups, CAISO stakeholder initiatives, and through the CPUC's demand response and Rule 24 Interconnection proceedings. Specifically, the lessons learned from the capacity procurement pilot for supply-side demand response[102] should be applied to making further program improvements in coordination with CAISO.

The CPUC should also take other near-term steps to enhance demand response programs, including accounting for locational values that could contribute to grid integration; defining transitional steps to full demand response program bifurcation through a "transition year" of 2017; providing policy guidance to the IOUs for demand response portfolios for post-2018; and beginning development of flexible demand response resources that can integrate into wholesale markets. In addition, the IDER proceeding could consider addressing the valuation of coordinated sets of DERs in terms of their contribution to grid integration. Furthermore, the demand response potential study, as discussed in Chapter III, should be used to set ambitious but achievable goals for integrating appropriate demand response resources into the pool of available flexible capacity. Through the RA proceeding and CAISO RSI initiative, DERs can be given an effective flexible capacity value and associated must-offer-obligations.

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[99] *See* National Renewable Energy Laboratory, 2015, "Multi-Lab EV Smart Grid Integration Requirements Study: Providing Guidance on Technology Development and Demonstration," *available at*: www.nrel.gov/docs/fy15osti/63963.pdf.

[100] Pub. Util. Code §740.12

[101] California Air Resources Board, Air Quality Standards and Area Designations, *available at*: www.arb.ca.gov/desig/desig.htm; California Air Resources Board, South Coast Air Quality Management District, and San Joaquin Valley Unified Air District (June 27, 2012), *available at*: www.arb.ca.gov/planning/vision/docs/vision_for_clean_air_public_review_draft.pdf.

[102] This pilot is commonly referred to as the "Demand Response Auction Mechanism."

2. Enhance Supply-Side Resource Flexibility: Procurement Mechanisms, Valuation, and Compensation

Storage Procurement. Three questions about storage resources need to be answered comprehensively in the context of grid integration: first, whether additional storage procurement will be needed and will be cost-effective in the near future; second, what other services storage can provide to the grid; and third, whether storage deserves a role in meeting local capacity needs.[103] The CPUC should holistically consider whether storage procurement would be a cost-effective way to procure flexibility, relative to other identified solutions, and which types of storage can provide needed flexibility characteristics.

Renewable Capacity Value. Changing the assigned capacity value of a renewable resource may—on its own—cause the renewable resource procurement mix to evolve in the next few years, thus decreasing integration needs. ELCC implementation has the potential to deliver to market renewable resources that will have lower overall demands on the system in terms of integration, thereby diminishing the effects of the duck curve, providing more flexible capacity, and possibly offering more ancillary services to the system. Going forward, the CPUC should enhance its understanding of the impacts of ELCC on both procurement and the make-up of the generation fleet, and evaluate these impacts for longer timeframes (e.g., over the next 3-10 years).

In addition, LCBF reform could better align the valuation of renewables with grid needs and send proper signals to the market to encourage the development of optimal renewable portfolios that meet the 50% renewable and other statutory mandates. The CPUC could expand its current efforts within LCBF reform to develop a renewable integration adder to create an operational flexibility valuation tool that could be applied to all resource types—not just renewables—to account for how each resource type supports or hinders the integration of renewables. Such an approach could allow long-term costs of grid integration (both procurement and investment) to be considered in an integrated manner.

3. Balancing the Role of Procurement vs. the Energy Market

Flexible Capacity Procurement. The existence of flexible RA requirements, CAISO's flexible ramping product, and the implementation of negative real-time market prices should, in concert, begin to provide financial incentives to generators to provide flexible capacity to the system as well as participate in the day-ahead and real-time markets in a way that supports grid integration. Because the flexible RA requirements have been in place less than a year, it is too early to determine how the requirements should be further improved in the short-term. However, it is unclear how the CPUC would deal with a near-term situation in which the CAISO observes that new operational needs are emerging and current RA resources are unable to meet those needs, or are not making themselves available to the market to meet these needs. For example, the CAISO has identified new operational needs emerging in the spring months of 2020, when they predict significant over-generation may occur.[104] The CPUC has not established a policy on whether this situation should be managed through market-based or procurement mechanisms.

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[103] D.13-10-040 ordered 200MW of distributed storage, and D.14-03-004 also ordered distributed storage (as part of 100MW storage mandate).

[104] For CAISO's discussion of this topic in their FRAC-MOO 2 initiative working group presentations, *see* www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.

Therefore, the CPUC, working with the CAISO, should conduct a thorough evaluation of the flexible RA program after it has been in place for one full compliance year. This evaluation could be done in mid-2016, and it could lead to an evolution in the program requirements. In considering potential changes to flexible RA requirement and the EFC qualifications, the CPUC should also continue to ensure that forward contracting by LSEs can occur with certainty and market fluidity. Over time, as less traditional sources of flexibility are developed, the EFC rules may need to evolve so that new resource types can be counted as flexible capacity, as appropriate. With regard to the must-offer obligation associated with a flexible RA resource (FRAC-MOO), the CAISO could similarly conduct an evaluation in 2016 to determine whether the obligation resulted in more resources making themselves available to support system needs, such as ramping, at critical times.

New Market Products. CPUC Staff should continue to review data provided by CAISO and produce analyses of negative pricing events and economic curtailments (such as the data presented in Chapter II). The agencies should work together to create a common understanding of the reliability signposts and how quickly their effects may increase in coming years. These evaluations would establish foundational knowledge for the CPUC and stakeholders to consider when analyzing whether, and under which circumstances, increasing economic curtailment is less desirable than changing procurement or market mechanisms to reduce curtailment.

The question of the appropriate balance between energy and capacity markets in providing compensation for generators will continue to arise, especially as the CPUC and CAISO closely monitor the sufficiency of flexible resources, and as CAISO continues developing new market products to solve emerging grid integration challenges. With regards to CAISO's new market products, such as Flexiramp, the CPUC should aim to understand whether these products provide additional compensation to flexible generators.

B. Long-Term Vision

Where does the "Grid Integration Policy Pathway" lead in the next 5-10 years?

Developing a long-term vision for grid integration policy will depend upon the experience and findings from the short-term approaches discussed above, along with the results of the analyses recommended in Chapter V. Therefore, the solutions discussed here are framed in terms of a "vision" for future CPUC policy and program development over the next 5-10 years, rather than as a set of already-formed recommendations. The achievement of each of these solutions is therefore discussed in the present tense.

One key aspect of the vision outlined here is the joint contribution of both DERs and supply-side resources to system flexibility and reliability—leading to a "fully integrated grid." The vision outlines how DERs will support the grid, whether behind-the-meter, on the distribution system, or at the transmission system level (through aggregation). A second key aspect is the modification of the shape of the gross load curve to better correlate with solar and wind generation. A third key aspect is the emergence of new *power system architectures* that would facilitate these visions, architectures that probably will blur or even eliminate the traditional distinction between "supply side" and "demand side" that has prevailed in power systems for many decades.

The "Grid Integration Policy Pathway" recommended in this paper would ultimately result in frameworks for markets, rates, and procurement to support least-cost approaches to achieving the necessary levels of flexibility and reliability, considering all possible resources. That is, many elements of this long-term vision are possible to achieve individually, but only when considered together and under least-cost frameworks, can true long-term solutions emerge. Elements of each of the solutions below have been discussed in recent published studies on grid integration, a selection of which are referenced in Appendix B.

1. Enhanced Flexibility from Distributed Energy Resources

The vision for enhanced flexibility is characterized by a wide variety of DERs that contribute to flexibility at the customer, distribution, and transmission levels of the entire power system, all working together to provide the most cost-effective grid services at the times and locations necessary. The exact combinations and methods of sourcing, integrating, and managing these DERs, in conjunction with the flexibility from supply-side resources, can be determined from the analytical and policy processes outlined in Chapter V.

Responsive customer loads. Responsive loads are created from a wide variety of solutions, including demand response, energy efficiency, TOU and dynamic rates, and storage. Demand response products, programs, rules, and appropriate accounting mechanisms (such as baselines) are implemented to allow demand response customers to shift load to absorb some of the excess supply during periods of renewable over-generation (and vice-versa during times without enough supply, such as evening). Thermal energy storage is added to building chillers. Energy efficiency program goals are redesigned to focus on reducing load during "new" net peaks based on the future solar-supply and net-load curves. In other words, they are targeted to creating savings during specific times of day and seasons. TOU and dynamic rates are designed to respond to system needs, and solar load shapes, and encourage customers to increase consumption during periods of likely over-supply and reduce during likely shortages. More responsive load is created from large customers such as water utilities, for uses such as water pumping and water recycling. A number of new load sources are developed to provide more flexibility in absorbing over-generation, and incentivized through TOU rates to operate during periods of over-generation. Examples include hydrogen or synthetic natural gas production.

Responsive PEVs. PEV charging rates, aggregator business models, and responsive car-side algorithms for PEV charging and discharging are integrated together to allow PEVs to make the most effective contribution. PEVs communicate with the grid when parked to absorb over-generation and support high demand and ramping needs by discharging (acting as storage resources).

Responsive distributed generation and storage. DG and storage are aligned with grid needs, such that their technical characteristics, scheduling, dispatch, and/or control are consistent with grid needs for flexibility and reliability. Micro-grids self-balance DERS that provide reliability or flexibility services to central grid via market or tariff mechanisms. The use of storage allows customers with DG solar to respond to system conditions such as over-supply, and evening ramping needs. This alignment happens through a combination of incentives, rate design (including TOU, dynamic rates, and NEM), and perhaps through new contractual arrangements between generation and storage owners, IOUs, aggregators, and/or local market participants. This could mean that SGIP and CHP are re-designed, advanced smart inverter standards are developed, more commercial integration is achieved between generation, storage, and load at the customer level, and closer regulatory integration is achieved across customer-side proceedings (i.e., the goals of the IDER proceeding are realized). If appropriate, economic incentives may exist for customers to install DERs that can provide *locational benefits*. In addition, storage interconnection and the rules governing storage's role on distribution systems are improved, including policy modifications and rule clarifications for charging, discharging, exporting vs. non-exporting, and customer-level vs. distribution-level.

2. Enhanced Flexibility from Supply-Side Resources

The vision for enhanced flexibility is also characterized by contributions from a variety of supply-side resources, including conventional generation, aggregated DERs that participate in CAISO wholesale markets, and out-of-state resources.

Flexible conventional generation. The LSEs procure flexibility from conventional generators in the most cost-effective manner. The existing gas-fired generators have retrofitted to allow for lower Pmin and faster start-up times. CAISO market evolutions provide market-based signals to encourage resources to behave flexibly through Flexiramp, EIM, and other market frameworks. Procurement frameworks and market incentives work synergistically to ensure that authorizations for flexible resources needed for future reliability can be provided in a timely manner, that revenue streams for flexible resources are adequate, and that if additional flexibility is needed from new and/or conventional resources, compensation mechanisms cover the costs of retrofitting or constructing. The responsiveness of the CHP fleet has been improved as CHP resources become market participants and therefore responsive to market conditions.

Demand response and storage participation in CAISO market. Viable and commercial business models for aggregated demand response and storage—which depend on appropriate CAISO market designs—become well-defined and established. Market signals result in demand response and storage resources that best match the grid’s needs for flexibility and reliability. In other words, the responsiveness of load and DERs becomes commercialized. In addition, markets are created to compensate demand response and storage resources for providing different types of services to support the distribution grid, such as distribution-system balancing (i.e., assisting the local distribution system in providing reliability or flexibility services to the bulk grid).

***New sources of ancillary services*.** Non-fossil-fuel resources such as wind, solar, storage and demand response play significant roles in providing ancillary services. In particularly, these alternative sources of ancillary services reduce the burden of relying upon gas-fired generators for spinning and non-spinning reserves, and thus contribute to mitigating over-generation conditions.

Expansion of EIM. Full implementation of the EIM, including day-ahead scheduling of resources through the EIM allows CAISO to better manage predicted over-supply conditions (through planned exports) and allows other balancing areas to mitigate over-generation events in real-time. Also, imports of resources from other balancing areas do not contribute to over-supply conditions, and are relied upon for providing flexibility.

3. Advanced Grid Integration Concepts and Frameworks

The vision for enhanced flexibility is also characterized by a variety of potentially new concepts and frameworks. While some of these concepts may be classified as “very long-term” thinking, some can and will have a profound impact on flexibility considerations, and thus their initial consideration should actually begin in the medium-term.

New resource procurement concepts. All procurement contributes to flexibility and enhanced grid integration capacity. The existing program division between “supply side” and “demand side” may not be advisable in the longer term for most DERs, all of which have the potential to contribute to creating flexible load and generation for the grid. In the vision for enhanced flexibility, new concepts may become fully operationalized, such as "all-source procurement" for flexibility. Resources may also be categorized based on the scale of their dispatch or control, such as "system-level resources," "distribution-level resources," "micro-grid-level resources," and "customer-level resources."

New resource valuation concepts like "all-source valuation." This concept becomes an integral part of all-source procurement. For example, an operational flexibility valuation tool (or perhaps an "integration subtractor" for DER, values all resource types for either their contribution to managing grid integration or causing grid integration challenges, and cost-effectiveness frameworks are integrated across all proceedings. For example, the IDER proceeding leads to an "all-technology valuation framework," building on its existing all-source valuation goals for DERs (see Chapter III). In other words, the IDER proceeding leads to a process which integrates the IDER cost-effectiveness framework with supply-side valuation processes, creating a consistent process for valuing all resources so that all resources can in the future be procured on a level playing field.

Re-defining "preferred resources." The CPUC and CEC reconsider policies related to "preferred resources" in the context of meeting flexibility needs. Specifically, the agencies reconsider whether it is still appropriate to include CHP as a preferred resource in the state's loading order if the persistence or growth of inflexible, baseload, fossil-fueled resources like CHP hinders the integration of zero-emitting, renewable generation into the electric grid. It may be appropriate to consider whether it is still reasonable to promote the growth of baseload fossil-fueled CHP unless such facilities can meet sufficiently strict efficiency standards, ensuring that new CHP resources do not displace zero-emission renewable generation.

Distribution systems as providers of grid services. Distribution systems will no longer be passive conduits for transfer of power from the transmission system to end-users. In the future, distribution systems will play a role in providing system-level services, including flexibility and reliability services that reduce the need for flexible resources, ramping resources and markets, and ancillary services. In the long-term, the DRP has evolved to account for all the distribution-level and customer-side measures discussed above. Distribution systems have been enabled by smart-grid technologies to facilitate responsive load, responsive customer-side generation, demand response, and storage. In the long-term, the DRP proceeding[105] (or a successor proceeding) allows distribution systems to become more self-balancing and to provide flexibility and reliability services to the grid, and smart inverters also play cost-effective roles in contributing to overall system flexibility and reliability.

New visions for overall power system architecture. CPUC and CAISO (and by extension FERC) have reconsidered the boundary between transmission and distribution, such as how distributed resources (including demand response, storage, DG, and micro-grids) are scheduled, dispatched, controlled, and compensated. The architecture can also extend to market models, such as possible models of localized energy markets (e.g., those envisioned at the distribution level under New York's proposed "Reforming the Energy Vision" architecture).

[105] R.14-08-013.

V. Moving Forward along the “Grid Integration Policy Pathway”

Chapter IV presented short-term “no regrets” approaches that the CPUC could undertake immediately to assist with grid integration, along with a long-term vision of where the “Grid Integration Policy Pathway” could lead. To achieve that long-term vision, particularly for a grid where the additional renewables necessary to reach a 50% renewables goal have been fully integrated at least cost, and with minimal reliability impacts, significant analytical work and planning will be required. Implementing the solutions outlined in Chapter IV(B) would require significant analysis, re-focusing existing proceedings, and actively promoting cross-coordination across proceedings and programs that currently may operate relatively independently. This chapter presents recommended areas of analytical focus, as well as procedural vehicles for progressing in an integrated manner towards the goal of identifying and implementing the least-cost solutions to grid integration.

A. Guiding Questions

Despite the relative success of California’s efforts to date, a range of questions related to grid integration remain unanswered due to a lack of information, analytical capabilities, or established frameworks for considering the questions in the most productive ways. Unanswered questions fall into the following categories:

1. **What are the flexibility characteristics of existing resources? What are future flexible needs? How might the two be mismatched?**
2. **How will adopted statewide policies, and/or decisions that may result from current CPUC proceedings affect the quantity of flexible resources in the future?**
3. **What are the least-cost solutions available to creating additional flexibility?**
4. **What are the technical issues related to over-generation and curtailment and when do they have the potential to create real reliability issues?**

Answering these questions will pose a significant but surmountable challenge on the path toward grid integration. The remainder of this chapter outlines a comprehensive set of actions that CPUC could undertake to address these questions and further our progress along the grid integration policy path.

B. Analysis of Existing Efforts, Future Needs and Approaches, and Least-Cost Solutions

What are the key analytical actions that the CPUC should pursue in the next 2-4 years, and how should these be pursued? What should the focus be of CPUC staff-led analysis, or analysis conducted in consultation/coordination with partner agencies?

1. Determine the Flexibility Implications of Existing Policies, Programs and Initiatives

Before launching into major program redesigns to address flexibility needs for grid integration, Staff recommends that the CPUC assess how far the programs currently being implemented will take us on the pathway toward a 50% renewables goal. Many existing CPUC proceedings, along with CAISO initiatives, are expected to result in increased quantities of flexible resources in the future. However, the CPUC currently lacks adequate assessment tools for considering how changes to CPUC programs and/or CAISO market operations would impact flexibility. It is imperative that California continually assess the progress towards grid integration as policies are implemented, especially while new programs are being considered and designed.

Staff recommends that the CPUC should focus in the next few years on understanding the implications of existing policies and emerging outcomes of ongoing proceedings, and answering the following:

- What levels of added flexibility are likely to be created by new DERs? Will any of these resources add to integration needs and/or meet integration needs? For example, will new distributed solar, based on the outcomes of the current NEM proceeding, increase or decrease the need for flexibility to be provided by other resources? Will co-installing storage change the need for flexibility from other resources on the system? If so, how much?
- What updates need to be made to our long-term planning assumptions regarding levels of energy efficiency, demand response, storage, DERs, smart inverters, PEVs, etc. that are likely be added in the future based on existing programs and recently adopted decisions? Will the rate of distributed solar interconnections be faster or slower due to current policies, lower technology costs and new industry financing and business models?
- How will customers' investment decisions (in energy efficiency, DERs, etc.) be influenced by retail rate reform or by new market products? Similarly, how will generators' investment decisions be influenced by new RA requirements or CAISO market operation enhancements?

2. Make Improved Assessments of Flexibility Needs under Future Procurement Scenarios with Higher Shares of Variable Renewables

The need to match electric generation and load is fundamental to the reliable operation of the electric grid. The timescale on which this matching must occur includes the sub-second level, 24 hours ahead with bids into the wholesale energy markets, a year ahead for sufficient capacity procurement, and 10 years ahead for sufficient new capacity. Flexibility needs exist across the entire spectrum, and understanding these different needs requires significant evaluation.

A comprehensive assessment is required to develop a better understanding of needs related to flexibility. Current law now requires that the CPUC "[i]dentify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner."[106] Therefore, this assessment must go beyond the current annual CAISO Flexibility Needs Assessment (near term) and the 2014 LTPP flexible needs modeling. The Joint Reliability Plan proceeding is focused on conducting a medium-term assessment of system, local and flexible needs that could provide a starting point for a comprehensive assessment of flexibility needs, which could be built upon in integrated resource plans.[107] The type of comprehensive assessment required would consider the different types of flexibility needed in ascending timescale order: to compensate for rapid changes in solar/ wind output due to

[106] SB 350 (2015): PU Code §454.51

[107] In accordance with SB 350 (2015), PU Code §452.52

weather, for ramping over one-hour and three-hour periods, to mitigate over-generation (a seasonal phenomenon), and to balance out seasonal variations of resources and loads.

This assessment might examine the existing generation fleet, in addition to the emerging set of DERs, for existing flexibility characteristics and should be recurring. This review would explore additional measurements of flexibility (beyond the existing EFC capacity valuation) to characterize the existing and planned generation fleet, as well as DERs. It might also need to combine assessments of current programs with complex analysis of specific future needs, not just the need for additional generating capacity. This may be effectively accomplished simultaneously with the development of integrated resource plans by the LSEs. Many studies are underway that should be integrated into the comprehensive assessment, and these are discussed here.

Load shape. Currently, CAISO's flexible capacity needs technical studies[108] make assumptions about the load shape of load-modifying resources, such as additional achievable energy efficiency (AAEE). The current modeling assumption is that the AAEE load shape is flat, meaning the impacts are evenly distributed across every hour of the year. Yet, more refined load shape data exist (e.g., in the Database for Energy Efficiency Resources) and could be used to generate a more accurate shape. A more accurate shape would likely reflect more energy efficiency impacts from lighting programs in the evening hours, thus reducing the CAISO's forecasted evening peaks and perhaps softening the evening ramp. Improved AAEE load shapes could potentially emerge from the 2015 IEPR demand forecast process for input into the next round of CAISO flexibility studies, and should be used in the overall assessment of flexibility needs outlined here.

Ancillary services. Studies are underway to consider the greater need for ancillary services with increasing renewable penetration, but these studies may not be sufficient to understand the rate at which the need will increase.[109] Therefore, the CPUC, in concert with CAISO and CEC, should aim to develop accurate predictions regarding how the need for ancillary services may change under different future procurement scenarios, and whether adequate resources presently exist to meet those needs. While conclusions from current modeling efforts indicate that additional procurement of ancillary services may not be needed at 33%, CAISO ancillary service markets have experienced scarcities.[110] This indicates that the models may need to be improved to better simulate potential real-world events and market participation, or market design may need to be improved.

Curtailment and Over-generation. Central to an improved assessment of flexibility needs is analysis of how inflexibility may lead to over-generation events, and what the root causes of renewable curtailment may be. Only with such analysis can the CPUC understand how much curtailment may increase under different scenarios. At present, neither the CPUC nor CAISO has predicted, with any degree of detail or certainty, how "low" the net-load curve will likely dip in years 2018-2024. Also, we do not currently understand how much non-congestion-caused renewable curtailment is being caused by forecasting errors/unpredictable situations,

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[108] *See* "Flexible capacity needs technical study process," *available at*: www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityNeedsTechnicalStudyProcess.aspx.

[109] *See* references in Chapter II, as well as Appendix B for a selected list of relevant literature.

[110] *See* CAISO, 2015, "2014 Ancillary Service Scarcity Event Report," *available at*: www.caiso.com/Documents/2014AncillaryServiceScarcityEventReport.pdf.

and how much is caused by an inability to dispatch conventional resources appropriately to meet load needs the following day. Understanding the nature of net load and which types of low net-load situations represent a need for flexibility is a prerequisite to understanding what levels of curtailment may be economically optimal. An improved assessment would consider different levels of flexibility need depending on different levels of over-generation.[111] This assessment would also have to take into account current procurement (RPS) contracting provisions and anticipate possible changes to those provisions, as to how they affect achieving economically optimum levels of curtailment. Box 1 elaborates on elements of a flexibility assessment.

Box 1. Key Elements in a Flexibility Assessment

Making improved assessments of flexibility needs require an integrated analysis of the power grid. The comprehensive assessment should include these key elements.

- Transmission system planning and locational constraints that may create local flexibility needs.
- Scenarios of future solar "supply curves" (which are under development through the RPS calculator project) and model outcomes that suggest the quantity and timing of flexibility needed during to match load with the predicted solar supply curve.[112]
- Hourly load shapes in IEPR forecasts. These are important to understand the impact of multiple demand-side initiatives on load.
- IEPR projections for DERs, which account for how flexible DERs may become.
- Robust and accurate DER growth projections from sources extrinsic to the IEPR, such as the DRP proceeding. (Having these growth forecasts and projections from the IEPR will enable the CPUC to study with specificity how these various approaches can impact net load and ramping needs.)
- Consideration of potential changes to CPUC's reliability standards. Reliability in the future may also depend on non-peak ramping and low-load spring-season conditions. The LTPP proceeding is currently considering how these standards and metrics could be changed, but decision making will likely be a long-term process.
- Analysis and assumptions regarding potential unplanned resource retirements that could create ancillary services shortages.

3. Conduct a Comprehensive Review of Potential Supply-Side and Demand-Side Approaches for Grid Integration

As discussed above, there are few established benchmarks and insufficient information available about the flexible capabilities of existing resources in California, as well as insufficient information about how much additional flexibility could be obtained from existing and new resources—a so-called "flexibility supply curve." The answers to the following questions are a pre-requisite to building such a supply curve so that the CPUC can ensure "optimal integration of renewable energy" as required by SB 350:

1) How effectively will potential distributed or supply-side approaches deliver additional flexibility?
    a. How much can the approach support the system's afternoon ramping needs?

[111] Through the LTPP, CAISO's analysis has bookended "unlimited curtailment" and "zero curtailment" cases, but an "optimum curtailment" case has not been developed.

[112] As discussed on page 15, the Energy Division is currently developing these through the RPS calculator v.6.1.

   b. How much can the approach mitigate over-generation during the periods of the year and hours of the day when over-generation is most likely to occur?
   c. Does the approach provide ancillary services? In what quantity?
2) What is the likely timeframe for implementing the approach?

The CPUC should, in conjunction with other agencies, conduct a comprehensive review of all the potential distributed and supply-side approaches that could provide increased flexibility on the grid, including, but not limited to, all of the short-term approaches and pieces of the long-term vision laid out in Chapter IV. This review would build upon the flexibility needs assessment and therefore would consider options for meeting operational flexibility needs at various time-scales. As discussed later in this chapter, a review of this scope and breadth would likely need to be conducted through a multi-agency work effort, and the results introduced into a comprehensive proceeding at the CPUC, to be reviewed by a diverse set of parties and stakeholders.

This review should project the quantity of various flexibility attributes from each approach, such as: ramping speed, ability to modify the net-load shape, provision of ancillary services, etc. This review would need to build upon the assessment of existing policies and programs (including their trajectories) discussed at the conclusion of Chapter III. Then, this review would determine what is possible under each of the approaches suggested in Chapter IV. After the potential for each approach is assessed, the CPUC could determine whether these desired outcomes are likely to occur based on existing policies.

Some of the approaches discussed in Chapter IV are already being employed or considered for grid integration purposes in other U.S. jurisdictions and worldwide (see Appendix A). However, many grid-planning authorities are choosing to pursue supply-side flexibility options first and are not yet challenging DERs to help integrate renewables. For example, in Germany and other European countries, transmission strengthening and transmission planning for renewables integration are receiving strong attention and given initial preference over other solutions. This is likely because of regional imbalances between the location of renewable resources and load. As discussed in Chapters III and IV, California may have many low-cost and "no regrets" options to pursue before considering transmission strengthening, and least-cost analysis will be important to determine prioritization.

4. Create the Modeling and Analytical Tools to Determine Least-Cost Solutions to Grid Integration

After determining what flexibility characteristics are possible to attain from the approaches suggested in Chapter IV, it will be possible to determine how to achieve the optimal or most effective portfolio of solutions. The most optimally efficient portfolio is one that would result in equivalent levels of system-wide flexibility at least cost. California's planning agencies have not yet completed a comprehensive analysis to determine least-cost approaches to flexibility and integration across all flexibility options, and doing so will require new modeling capabilities and methods.[113] A further discussion of how production cost modeling could be used to understand least-cost solutions is given in Box 2.

Two basic questions about least-cost solutions to answer through modeling are:

1) What are the potential economic costs to California of the projected levels of curtailment, increased need for ancillary services, potential reliability impacts from over-generation, and other potential costs associated with going from 33 to 50% renewables while maintaining a "status quo" system?

2) How can these costs be weighed against the costs of pursuing the grid integration solutions outlined in Chapter IV?

In other words, if the CPUC Staff considered all identified resource options and strategies currently being considered in CPUC proceedings what would we determine are the most cost-effective solutions to achieving the necessary levels of flexibility? What are the least cost-effective options? The CPUC should determine what types of modeling approaches would be necessary to answer this question and how such modeling approaches could be implemented. A prerequisite to any comparison of integration options is an understanding of the cost of curtailing renewable generation. We know that curtailment currently can be valued based on (a) the real-time market price and (b) the price to replace curtailed RPS kWh with other RPS kWh. The CPUC should be considering other costs of curtailment, or other negative economic consequences of grid integration, that could be easily captured and understood.

Furthermore, determining the least-cost solutions to grid integration necessitates an understanding of what amount of curtailment (in MWh) throughout the year is economically efficient or optimal. This includes understanding under which conditions continued economic and/or manual curtailment is actually the preferred solution to dealing with over-generation or other reliability issues. So the analysis must determine the true cost of curtailing one kWh of renewable generation at different times of year.[114] The economic analysis should also provide understanding of whether negative-market pricing events achieve an efficient result and how many generators are likely to continue generating at different negative price points. This could inform whether "deeper" negative prices should be part of a grid integration strategy.[115]

Finally, least-cost solutions must also account for different reliability standards and metrics, and the costs and provisions of ancillary services. The CPUC should consider whether alternative definitions, standards, and metrics of reliability would allow for lower-cost renewable integration while still providing acceptable levels of electric service to all customers.

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[113] CPUC should assess to what extent CAISO's modeling efforts will begin to address the goals described below. Such modeling has been done in the abstract by the International Energy Agency, but not in any specific utility jurisdiction anywhere in the world, as far as we know, so this is far from an "off-the-shelf" process.

[114] Note: this is currently under development in the RPS calculator exercise, but an actual "avoided cost" for grid integration solutions that reduce the incidence of renewable curtailment should be calculated and assigned as a beneficial value of those solutions.

[115] For more analysis on negative pricing events, *see* the CAISO Department of Market Monitoring's 2014 Annual report, *available at* www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

Box 2. Production Cost Simulations to Assess Integration Costs

Integration costs are largely the costs of rebalancing the surrounding fleet of transmission and generation resources around the intermittent renewable resources. Integration of intermittent resources will lower costs in some ways, such as by reducing fuel burned in conventional power plants. Conversely, intermittent resources can increase costs from operating fuel-based resources, because they will not consistently operate at their most fuel-efficient levels, and they will need to cycle more often, thus increasing maintenance requirements. The assessment of these integration costs could be best served through a production cost simulation, which is a two-step process. First, the current power system is simulated, and costs such as fuel, maintenance, and variable cost are tabulated and analyzed. Then, intermittent renewable resources are added to the fleet, another production simulation is made, and a new set of fuel, maintenance, and variable operating costs is captured and analyzed. The incremental added costs comprise the integration costs of the new intermittent resources.

Production cost simulations are a good way of gauging cost trajectories, or of gaining an appreciation for order of magnitude cost increase. Even if it is hard to be precise or entirely accurate in the forecasted operation of a large and complex electric system, it is possible to compare fuel quantities, energy quantities, general patterns of operation, and gain insights. This enables assessments of the cost impact of adding incremental generating resources, which can then be compared to the decreased costs of operating conventional generators.

Production cost simulations are often performed probabilistically, so that multiple scenarios can be assessed at the same time, with a range of outcomes. Scenario analysis shows how mixtures of future resources can impact production costs, what cost impacts can be attributed to intermittent renewables, and what other resources can synergize with renewables to reduce costs. Integration costs of intermittent renewable generators are very sensitive to interactions with everything else happening in the electric grid, and a range of integration costs can result from alternative scenarios of resources. Thus it is important to simulate the production cost impacts of additional intermittent renewable generation together with other scenarios about future energy grid developments.

C. Developing Grid Integration Policy

What are the most significant policy questions that could be addressed through a grid integration planning process? What policy questions could be addressed in existing proceedings?

There is no single current CPUC proceeding designed to address a challenge that implicates nearly all of our work in electric programs and regulation. The CPUC often initiates proceedings to address one emerging technology or policy area, and these types of proceedings do not look holistically at the interrelationships with other technologies, programs, or the interactions between decisions. SB 350 mandates the CPUC to develop a process for conducting integrated resource planning, and an integrated process could be an effective vehicle for developing comprehensive grid integration policy.

Furthermore, because procurement policies are currently made in supply-side and demand-side silos, there is a structural impediment to addressing mismatches of load and supply and the reliability issues that must be anticipated under a high renewables future. While the technology-specific or program-specific approach has worked well in the past, the grid integration challenge provides an opportunity for a more integrative or comprehensive approach that encompasses potentially all technologies and programs. This approach is suggested in the SB 350 requirements to develop a "diverse and balanced portfolio" through implementing an integrated resource planning process.

To determine how best to answer the policy questions raised throughout this paper, the CPUC would need to consider re-focusing proceedings and programs. Grid integration planning could lead towards an action plan based on the results of the analyses discussed above, and focused on a long-term vision of an integrated grid. The analytical work needed to understand flexibility needs and approaches would be best overseen in a comprehensive process. Comprehensive grid integration planning would involve three discrete tasks:

1. Create new guidance for existing proceedings and programs to implement "no regrets" short-term approaches to grid integration;
2. Oversee the comprehensive analysis of challenges, flexibility needs, and solutions discussed in this chapter; and
3. Draw conclusions regarding which solutions to grid-integration should be pursued to achieve a long-term vision, and how these solutions should be prioritized and implemented.

By focusing on these tasks, the CPUC could determine the answers to many existing policy questions, including:

- How should the costs and benefits of flexibility options be assessed? How should the GHG benefits of different options for flexibility be weighed?
- Is the current mix of compensation from capacity contracts and energy/ancillary services market revenues sufficient to compensate the flexible generators that the system relies upon, and which may be relied upon more heavily in the future?
- What are the potential additional lowest-cost sources of ancillary services, and how can their development be incentivized?
- Should the CPUC consider a new vision for overall power system architecture?

The first task is to provide guidance to various CPUC proceedings related to short-term actions. Next, when a least-cost flexibility analysis is complete, the CPUC can determine the best way to align individual proceedings to optimize grid integration solutions over the longer term. This could be a part of the integrated resource planning process required by SB 350. It would be up to the individual proceedings to consider re-designing procurement and demand-side programs to address the short-term grid integration approaches and long-term solutions. Table 3 provides a cross reference with those approaches and solutions, and suggests how Staff's recommendations could be addressed by answering key questions through new or existing proceedings.

Table 3. Key Policy Questions to Answer through CPUC Proceedings

Topic	Questions to Consider	Relevant Proceedings	Approaches in Chapter IV
DERs: Guidance can be developed through the IDER or other integrated planning process for the multiple programs that deal with DERs. One result would be to determine if additional or revised incentive programs are necessary.	(a) How should integration costs and benefits for DERs be determined and allocated? (b) What are the best ways for load-modifying programs to contribute to grid integration? (c) What operational, locational, and other characteristics are desirable for customer-sited renewable energy projects to achieve the greatest system-wide benefits? (d) Which entities should schedule, dispatch, and control future DG resources, and what are the appropriate roles and relationships of ISO, IOUs, customers, and third-parties?	DRP, SGIP, Storage, DR, IDER, EE, Rates, Interconnection, and RPS	(IV-A) Enhancing Flexibility from Distributed Energy Resources (IV-B) Responsive loads, responsive EV charging, responsive DG and storage, new types of load
Storage and PEVs: Guidance can be developed for proceedings focused on utility-scale and distributed storage procurement to focus on how storage should be incentivized and/or procured to produce the maximum flexibility benefit at lowest cost.	(a) What forms and configurations of storage should be encouraged, given the results of analyses on flexibility options and least-cost flexibility modeling? (b) Should the Commission be incentivizing customer-side storage? (c) What should the Commission's long-term strategy for PEV-to-grid discharging applications be?	Storage, but also within a unified framework across several relevant proceedings, including NEM, SGIP, PEVs, and TOU.	(IV-A) Enhancing Flexibility from Distributed Energy Resources (IV-B) Responsive loads, responsive EV charging, responsive DG and storage, demand response and storage as significant market-based supply-side resources.
Procurement and Resource Adequacy. Guidance can be provided to existing or future procurement proceedings to consider factors for evaluating flexible procurement needs.	(a) What factors should be considered when evaluating applications for new thermal generation? (b) Should the CPUC mandate specific flexibility characteristics of any new conventional and renewable resources, such as Pmin and start-up time? (c) Should new renewable generation be required to provide certain ancillary services?	LTPP, RPS, RA, JRP	(IV-A) Enhancing Supply-Side Resource Flexibility (IV-B) Responsive conventional generation, demand response and storage as significant market-based supply-side resources

D. Conclusion: Making Progress along the Grid-Integration Policy Path and Developing an Action Plan

This paper has identified the key signposts of the grid integration challenge, reviewed the wide variety of actions underway to address the challenges, recommended enhancements to current actions, put forth a long-term vision, and identified the key questions and analyses that have yet to be completed. Staff has not made recommendations of specific procedural vehicles, other than to suggest that the existing siloed nature of CPUC proceedings does not lend itself to comprehensive consideration of solutions to grid integration challenges, and therefore a comprehensive type of planning process is suggested.

This paper covers a multitude of small and large actions that the CPUC could undertake. Such actions, underpinned by the analytical and policy considerations addressed in this paper, create a framework for developing an action plan for grid integration. The action plan could be CPUC-specific, but to be more effective, it would likely also require developing coordinated plans with other agencies, especially with the CEC and CAISO.

As outlined in this paper, there are many areas where we do not have a full and complete understanding of the problem, or where different organizations' interpretations diverge. Thus, a first step is for the CPUC, CEC and CAISO to work towards consensus on determining flexibility and integration needs and metrics. Admittedly, the path forward for creating this consensus is unclear. A first step may be for the three agencies to find a common "problem statement" of integration and flexibility concerns (such as over-generation and curtailments). A second step would be for the agencies to agree to some shared organizational goals. A third step would be to agree to coordinated actions.

Most importantly, while the potential reliability or economic impacts from integrating greater than 33% renewables onto the grid have not yet materialized, Staff stresses that action should not be delayed until these impacts become real. The various potential solutions discussed in this paper will require thoughtful decision-making that will take many years to develop. The longer state agencies wait to prioritize the needed analysis and determine least-cost solutions to grid integration, the more difficult it may become to implement those solutions. Staff recommends that the CPUC, working with other state agencies, act quickly to avoid passing up available and low-cost solutions that have already been identified. If actions are not taken in the short-term to plan for integrating significantly more renewable energy, California may lose opportunities for no regrets solutions. Staff has recommended potential short-term actions and analyses to be completed, and has laid out a visionary "end-state" for an electric grid where high proportions of renewable energy are fully integrated.

The rapid development and deployment of exciting new technologies calls out for rapid regulatory response. As the adoption by residential and commercial customers of DER technologies including solar resources, PEVs, batteries, and smart inverters increases, the motivation for adaptive policymaking should increase. The time is ripe for policymakers to face head-on questions regarding how these technologies can and will transform the grid.

In Staff's opinion, it is important that CPUC conducts analyses on a range of options and finds the least-cost solutions to grid integration, rather than having the "preferred solutions" decided elsewhere, without the same analytical vigor that the CPUC can apply through a comprehensive planning and/or procurement proceeding. The future grid integration challenge for the CPUC is much more than just providing adequate resources for CAISO to dispatch. Addressing the grid integration challenge likely means that CPUC and CAISO need to find new ways to work together to make procurement, rates, markets and grid operations fit together to ensure reliability in a least-cost manner.

The convergence of many promising technologies and new market mechanisms is evidence that progress can be made along the grid integration path, and Staff is hopeful that the new mandate for 50% renewables will lead to institutional opportunities in the near term. If the recommendations made in this paper are considered in a comprehensive and thoughtful way, then the most effective and cost-efficient policies to address grid integration can be put in place before significant quantities of additional renewable resources are delivered to the grid. The low-carbon grid of the future depends on the CPUC's success.

Annex to Chapter V: Staff's Initial Ideas for Strategies within Existing Proceedings

This table contains Staff's initial ideas for strategies that could be implemented within existing proceedings to further grid integration. Some of the strategies are programmatic, and some are analytical tools. Many of the strategies could be implemented in multiple proceedings, but given how complicated this might be, they would likely need guidance from a comprehensive grid integration planning process.

Category	Example Strategy Ideas	Relevant Proceedings
Load-Modifying Programs	*Use improved load forecasting to evaluate energy efficiency program goals and potential.* The CPUC could, through the Joint Agency Steering Committee (JASC) process, revise forecasts of AAEE to reflect a "realistic" hourly variation in load impact. This would be possible based on an improved Energy Efficiency Goals and Potential study, which should be revamped in the next planning cycle to make it sensitive to TOU rate design.[1]	EE
	Develop analysis of continued improvements in retail rate design. Based on the outcomes of TOU pilots over the next two years, the CPUC could authorize more advanced pilot programs to experiment with dynamic rates. If a rate structure similar to the CAISO proposal is implemented in the near term, then Staff could analyze the observed impact of "super off-peak" rates for shoulder months and determine the impacts on load and over-generation.	TOU NEM
	Develop an "integration subtractor" for demand-side resources. This would apply to determining the cost-effectiveness of resources such as demand response, energy efficiency, storage, and smart-inverter-based DG that positively contribute to grid integration. This would mean that resources get credit for their positive contribution to integration.	IDER DR Storage-Interconnection EE SGIP DRP
	Consider PEV charging regimes and rates. Ensure that retail rates are favorable for PEV charging at the "right" times, consistent with time-based grid operating and energy costs, ramping needs, and over-generation conditions.	PEV TOU
	Assess TOU rate impacts on GHG. Capture potential GHG reductions from predicted/projected TOU rates, due to shifts in energy use from periods of high carbon intensity to periods of low (or even zero) carbon intensity. Understanding whether the implementation of robust TOU rates for all customers would reduce GHGs would aid progress in the GO Executive Order would be valuable information.[2]	TOU

	Create an all-source, all-technology valuation framework to apply to demand- and supply-side resources. A staff proposal in the IDER proceeding recommends leveraging the work to align demand-side cost-effectiveness frameworks to also coordinate with supply-side valuation models to create an all-source valuation framework that reflects state policies and goals related to climate change and GHG reduction. The valuation framework would require inputs that quantify the value of grid services and integration.	IDER PEV RPS DRP LTPP
Storage	*Declining CSI-type incentive structure for Storage-PV co-installations*. Consider the cost-effectiveness of a declining CSI-type incentive structure applicable [only] to PV customers who invest in storage.	SGIP Storage DRP
	Electric vehicle discharging regimes. Ensure that tariffs are favorable for PEV discharging at the "right" times, consistent with time-based grid operating and energy costs, ramping needs, and over-generation conditions.	PEV TOU
Supply-Side Programs	*Evaluate compensation for flexible resources.* Is the current mix of compensation, from capacity contracts and energy market revenues sufficient to compensate the valuable flexible generators that the system relies upon, and which may be relied upon more heavily in the future? If they are not, then a re-scoped RA/ JRP proceeding could consider developing new compensation schemes for these resources, in coordination with the CAISO's evaluation of Flexiramp and other mechanisms to compensate flexible generation through the energy markets.	RA JRP
	Re-consider CHP program benefits and costs. Opportunities to increase the flexibility of the existing CHP fleet include repowering and making excess capacity available for dispatch. Recent utility-led competitive solicitations have valued locational benefits and flexibility needs and have transitioned facilities from baseload to dispatchable operations when feasible. The CPUC can encourage new CHP to be located in areas with high location benefits and with operational profiles that benefit the grid.	CHP DRP
[1]Currently, the CEC rate forecast used in the Energy Efficiency Goals and Potential Study consists of a single average rate value for each year and each utility. [2]Staff expects that this will be studied in the 2016 LTPP, based on load impacts from the current JASC Supplemental Rate Analysis.		

APPENDIX A: California in International Context

California is already a global leader in adopting high shares of renewable energy and addressing the grid integration challenge. Many of the grid-integration issues and potential solutions discussed in this paper are at the forefront of global practice and thinking. However, a growing number of other U.S. states and other countries around the world are beginning to more seriously address the grid integration issue. This is particularly true for countries with high shares of variable renewables. And their experience and thinking is relevant to the choices and approaches California faces now and in the future.

Germany is another one of the global leaders in adopting high shares of renewable energy. In Germany, renewables now provide close to 30% of Germany's power on an average basis. And on some peak days in 2014, solar and wind alone supplied close to 80% of peak power demand at specific times of the day. In the future, Germany is targeting a 35% average share from renewables by 2020 and a 50% average share by 2030. Because of Germany's feed-in tariff law, renewables have dispatch priority, meaning they are always used first, sometimes leaving very little power demand left to be supplied by coal, nuclear, and natural gas plants, which must reduce their output, not operate at all, earn revenue through ancillary markets, and/or export to neighboring countries.

However, Germany has not had to face serious difficulties with grid integration yet, for a number of reasons, including active import/export markets with neighboring countries, the fact that conventional generation over-capacity exists due to lowered demand from economic conditions, and the fact that Germany's grids are historically strong (over-designed). So Germany is just beginning to comprehensively confront the grid integration issues that will arise in the future. In 2015, the Germany government issued a "green paper" with proposed changes to Germany's electricity law and market, which were under discussion.

Striking evidence of Germany's current sufficiency of grid integration capability comes from two specific events that occurred in 2014-2015. First, during the solar eclipse in Europe in March 2015, Germany experienced a ramp-down of about 6 GW of solar generation capacity in one hour, followed by an increase of about 13 GW in solar capacity during a 75-minute period at the end of the eclipse. These ramping rates are about the same magnitude and more than twice as rapid as those projected by CAISO for California by 2020. Germany's existing power market design and conventional generation resources handled these huge power swings with no power outages, by using existing mechanisms, particularly market price swings, imports and exports, and flexible response of hard-coal power plants. Second, during late December 2014, wind power provided over 40% of Germany's power capacity (i.e., 30 GW out of 70 GW during the daytime) power for several days in a row, and then virtually zero power the next day. Germany's power system was able to handle this huge change from high-wind to no-wind from one day to the next, in similar manner to how it handled the eclipse.

Denmark is another global leader. Denmark is targeting 100% of its electricity from renewables by 2035, arguably the most ambitious target of any country. In 2013, the capacity of renewable energy in

Denmark was about 5 GW, which was just slightly less than the peak power demand of Denmark's entire power grid (about 6.5 GW). Most of this 5 GW of renewables is onshore wind, with a smaller share of offshore wind, and a small amount of solar PV (about 0.5 GW). In 2013, wind power provided an average 33% share of Denmark's total power demand. In January 2014, wind supplied an average 62% of total power demand. On one day in January 2014, wind generated an amount of electricity equal to 105% of Denmark's power demand for the 24-hour period. Denmark has many plans and strategies for grid integration that are evolving, some of which are discussed later in this Appendix.

Other countries with high shares of renewables include Ireland, Spain (>25%), and Italy (10% for entire country, 30% for southern Italy). In these countries, much of the total renewables is variable wind and solar, and these countries certainly face grid integration challenges in the coming years. Spain has an abundance of natural gas plants that could be used for integration, but many of these are inflexible combined-cycle plants, and natural gas prices are so high that gas is generally not economic in Spain. In both Spain and Germany, many gas plants are being considered for retirement, in favor of keeping (or upgrading) flexible coal plants. Spain's situation is similar to California in being isolated from neighboring jurisdictions, with only modest interconnection capability. So far, Spain has relied on wind power curtailment as a primary integration strategy, coupled with its reservoir hydro and pumped hydro resources.

Several countries have very high shares of renewables, in the 60-80% range for example, such as Iceland, Norway, and New Zealand. But in these cases the renewables are not variable, but dispatchable hydro, geothermal, and biomass. So the grid integration challenge, which arises primarily from large shares of variable wind and solar, has yet to reach these countries.

In the U.S., beyond California, the MISO, PJM, and ERCOT grids are among the leaders in terms of renewable shares and grid-integration strategies. These jurisdictions face many of the same challenges as California does. However, these jurisdictions face different market, procurement, regional interconnection, and operational conditions relative to those in California, so solutions and strategies may or may not be relevant. (Much further analytical work could be done on exploring this relevance.)

A. Curtailment Experience and Strategy

More than a dozen jurisdictions with high renewables shares in the U.S. and around the world face curtailment issues currently and in the future. China is experiencing the highest levels of curtailment among any jurisdiction, with some provinces curtailing 15-25% of wind power output due to insufficient local demand coupled with lack of transmission capacity to other regions. Spain, which received 21% of its electricity from wind in 2013, routinely curtails wind power for grid reliability and balance. Although wind curtailment has been about 2-3% in recent years in Spain, this still amounts to hundreds of millions of Euros per year in economic losses to wind generators. Japan allows up to 8% curtailment without economic compensation, although data are lacking on actual levels of curtailment.

Other countries with high shares of renewables have managed so far to avoid high levels of curtailment, including Portugal, where curtailment is legally not allowed except under declared grid "technical problems" (which have so far not happened despite the fact that wind power supplied 20% of Portugal's electricity in 2012). Wind curtailment in Italy was 1.2% in 2012, and in Ireland was 2% in 2012. Curtailment in Italy occurs mostly on low-load days when all conventional generation is at Pmin and adequate reserve margins must be maintained. Denmark has virtually no forced curtailment, although sometimes a number of hours per month of (economic) negative-price curtailment, despite the fact that wind supplies 33% of Denmark's electricity. (And on at least two specific 24-hour periods in 2014, wind supplied electricity equal to 100% of Denmark's total national electricity demand.) Germany currently curtails about 0.3% of wind power.

In other countries with high amounts of solar, no solar curtailment yet occurs. This includes Italy (18 GW of solar in 2013) and Germany (38 GW of solar in 2013). Due to the island nature of the grid and huge influx of solar in recent years, Hawaii may have the most solar curtailment currently of any jurisdiction in the world. Hawaii's experience is thus at least partly relevant to California.

Among U.S. states, curtailment levels have declined in some jurisdictions in recent years, and in 2013, curtailment levels were typically less than 2%, except for MISO at 3%. ERCOT had seen levels reach 8% and higher during 2008-2011, but by 2013 had declined to 2%. Primary reasons for curtailment are transmission constraints and oversupply in most jurisdictions, plus high wind ramps and voltage control in a few jurisdictions.

Virtually all of past and current curtailment, and thinking about the future, is based on over-generation of wind power, not solar, and the consequent need to curtail wind power. California is unique among other jurisdictions, with the exception of perhaps Hawaii and Southern Italy, in the degree of solar on its grid, and thus the issue of solar curtailment and over-generation from solar rather than wind. Germany has very high shares of solar already, but curtailment and over-generation of solar are not primary issues because of Germany's interconnection with neighboring countries for imports and exports.

Solar curtailment differs from wind curtailment in that the curtailed solar is more likely to result from over-generation conditions present during mid-day periods of peak or near-peak load, and thus the solutions may include increasing load during peak periods (in contrast to a hundred years of power-sector practice to try to reduce peak loads). Also, solar contributes directly to morning and afternoon net load ramping requirements, and curtailment of solar is more likely to be associated with insufficient ramping capacity. Wind may also be curtailed for these two reasons, but much wind curtailment also occurs for other reasons. For example, in Ireland, wind curtailment mostly happens during nighttime, when all conventional generation is running at Pmin and thus can't be reduced further.

B. Grid Integration Solutions and Strategies

A wide variety of grid integration options are being discussed and considered in other jurisdictions. The two most common options are: (1) Transmission strengthening and transmission planning for future renewables; and (2) increased flexibility of conventional generation. In Germany, these two options are receiving the most attention, particularly transmission planning accounting for where renewable resources will be developed in the future (plus addressing existing north-south imbalances with respect to existing wind generation and load). Germany is also focusing on retiring its fleet of inflexible (and GHG-intensive) lignite plants, in favor of flexible hard coal plants. (Coal is currently much cheaper than gas in Germany, so much existing gas capacity goes unused due to economics.) Another priority for Germany is heat thermal storage coupled with flexible CHP plants in an electricity-following mode, along with inter-region transfers and interruptible loads in industry.

Denmark also is focusing on flexible CHP plants coupled with thermal heat storage (to allow the CHP plants to be operated flexibly without sacrificing heat load), and also highly flexible coal plants, imports/exports, and tighter market integration with the Nordic Pool market. Denmark's attention to grid integration dates back to the 1990s, and many of its CHP plants and coal plants have been designed and built for highly flexible operation.

However, none of these options are necessarily the first priorities for California. Thermal storage in California's context is more likely to encompass thermal storage in chillers for air conditioning, not CHP plants. Where other countries like Germany and Denmark are focusing on flexible coal, California must focus on flexible natural gas. (European countries are not focusing on flexible gas because gas power is much more expensive than coal power currently, even when carbon prices are included under the European Emissions Trading System, which applies to power plants.)

Other options being discussed, studied, incentivized, or implemented in other jurisdictions include:

- Customer-side batteries coupled with solar systems. Similar to California, both Germany and Italy provide incentives for customer-side batteries coupled with solar. In Germany, more than 10,000 such systems already exist. Germany, however, has begun to reduce its emphasis on storage, and so the residential storage program has been scaled back. Italy's situation, particularly southern Italy, may be most similar to California in dealing with large shares of solar and the consequent grid integration questions.
- "Virtual power plants" combining DR, storage, and DG at the customer level, and aggregated over large number of customers. Germany is actively investigating this idea.
- Wind power contribution to voltage and VAR support, and down-ramping ancillary services. Wind turbines in Ireland have these capabilities, but these capabilities are currently not being used.
- Non-synchronous limits. Ireland currently limits wind power such that wind power generation plus imports on HVDC transmission lines do not exceed 50% of load ("system non-synchronous penetration limit"). Ireland is working on improvements to allow this limit to be raised to 75%.
- Negative prices are also increasing part of a market-based strategy for renewables integration in several European countries, especially Germany and Denmark.

C. Energy Storage and Demand Response

Very few jurisdictions are yet actively addressing the subject of energy storage in terms of contribution to flexibility and integration of renewables. Many RD&D pilot projects exist around the world, and a number of commercial IPP storage projects have emerged in some U.S. jurisdictions, where storage can sell into wholesale, capacity, and/or ancillary markets.

In past years, many people have thought of energy storage first when it comes to integrating and balancing renewable energy on power grids. But many experts, scenarios, and analyses are now showing that power grids can reach high shares of renewables without much energy storage, at least in the range of 25-40% renewables share, because of the many other options for integrating and balancing variable renewables. This includes studies in recent years by the U.S. National Renewable Energy Laboratory, the International Energy Agency, Agora Energiewende, and others.

The evolution of thinking about storage in Germany is instructive and potentially relevant to California. Energy storage has played almost no role in Germany's integrating and balancing renewables so far, aside from a modest capacity of pumped hydro. A few years ago, Germany had plans to develop a whole network of additional pumped-hydro facilities, but has reconsidered and abandoned those plans, and now many in Germany believe that Germany can reach up to 40% shares of renewables or higher with no additional energy storage. For example, Agora Energiewende studies show storage only being used after 2032, as Germany approaches a 50% share of renewables. Only a few pilot projects exist. Of course, there is interest in household-level storage in conjunction with the "self-consumption" economic model for distributed solar PV, now that retail electricity tariffs (and thus avoided energy costs from self-generation) are so much higher than the feed-in tariff rate for selling to the grid. During 2009-2013, the German government created a "small residential storage" program that provided incentives for distributed customer-side storage, with the aim of fostering self-consumption of distributed solar. However, this program continues at only a small scale.

Denmark also has no plans for electricity storage, partly because it has such well-developed heat (thermal) storage, which is much cheaper and equally effective for balancing variable renewables on the power grid. Long-term, Denmark is considering other ideas for energy storage, such as generating synthetic natural gas or hydrogen from excess electricity generation, and storing the natural gas and/or hydrogen (in small percentages) within the country's extensive natural gas storage capacities.

Demand response has yet to make any significant contributions to flexibility and integration anywhere in the world. This means that California's efforts to utilize DR for grid-integration purposes, are among the leading efforts worldwide. In the U.S., most DR comes in the form of peak shaving and/or ancillary reserve capacity, and there is a large capacity (> 90 GW) of contracted DR according to a 2014 FERC report. But DR in the U.S. is typically called upon just a handful of hours (<100) per year. In contrast, Germany has less than 1 GW of DR, but this capacity is used daily and actively in the ancillary/balancing markets. (It is being sold into the balancing/ancillary markets, by large power generators to complement their existing conventional generation for the balancing markets.) Some ISOs in Germany have also been contracting directly with large demand response providers on a pilot basis. However, the regulatory authority does not explicitly include demand response in its planning, or set rules specifically for demand response.

D. Capacity Markets and Declining Full-Load Hours of Conventional Plants

Capacity markets or capacity-remuneration mechanisms are under discussion in some jurisdictions as a way to ensure sufficient balancing and flexible capacity in the longer-term. Given California's established RA and FRAC-MOO frameworks, the relevance of these discussions to California may not be too significant. Nevertheless, they may still be instructive.

There is currently a prominent debate in Germany about keeping an energy-only market (EOM), or instituting some type of capacity-remuneration mechanism. EOM advocates say an EOM is enough to deliver system reliability. If EOM is followed, Germany is considering adopting a “strategic reserve” of capacity in case it is needed, which might be outside of the normal market. If this capacity ends up not being needed over a period of years, then it could be eliminated. Capacity market proposals include a “full” capacity market in which all capacity is treated equally and eligible for auctions, and a “targeted” capacity market in which the government would define different types and levels of flexibility needed, and only resources able to provide those flexibility attributes would be eligible for auctions.

Part of the debate about capacity markets in Germany and elsewhere is the recognition that inevitably in a higher-renewables future, full-load hours of conventional plants will decline in the future. For example one analysis by Agora Energiewende shows that by 2020, Germany will have 20 GW of dispatchable resources that are dispatched less than 200 hours per year, given the projected growth of renewables and their model of power system operation. So the question for policy makers becomes the issue of the profitability (and market adequacy) of resources used at very low full-load hours, under EOM or capacity market scenarios.

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GLOSSARY

TERM	DEFINITION
ancillary services	The term "ancillary services" as defined by Federal Energy Regulatory Commission (FERC) in 75 FERC ¶ 61,080 (1996) are those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. In Order 888, FERC defined six ancillary services: (1) scheduling, system control and dispatch; (2) reactive supply and voltage control from generation service; (3) regulation and frequency response service; (4) energy imbalance service; (5) operating reserve – synchronized reserve service; and (6) operating reserve – supplemental reserve service. (D.12-11-016, Footnote 42 at 24).
balancing area/ balancing authority	Refers to the geographic area of the electric power system in which electrical balance is maintained. In a balancing authority area, the total of all generation must equal the total of all loads (as supplemented by electrical imports into and exports out of the area).
California Independent System Operator (CAISO)	The CAISO operates the wholesale electric grid for over 80% of California. It is a non-profit corporation that provides open and non-discriminatory access to state's wholesale transmission grid, supported by a competitive energy market and comprehensive infrastructure planning efforts.
California Energy Commission (CEC)	The CEC is the state's primary energy policy and planning agency. Established by the Legislature in 1974 and located in Sacramento, its responsibilities including forecasting future energy needs, setting energy efficiency standards, and supporting research that advances energy science and technology.
Combined Heat and Power (CHP)	Combined heat and power (also known as "cogeneration") means the sequential use of energy for the production of electrical and useful thermal energy.
coincident peak demand	Coincident peak demand is the demand from an aggregate of customers that coincides (in time) with total demand on the system. A region's coincident peak is the actual peak for the region (e.g. the CAISO balancing area), whereas the non-coincident peak is the sum of actual peaks for sub-regions (e.g. the service areas of the LSEs within the CAISO balancing area), which may occur at different times.
curtailment (of renewable energy): local and system curtailment, economic vs. manual curtailment	Curtailment of renewable energy output causes a downward adjustment in the amount of electricity being generated by a renewable resource. It may be required by the system operator to maintain reliability, or may occur through the market due to supply conditions. Local curtailment is related to localized transmission congestion. System curtailment is related to a system-wide over-supply condition. Economic curtailment occurs through the wholesale market, based on a generator's bid price. Manual curtailment is ordered by the system operator and in the CAISO is accomplished through exceptional dispatch (manually "calling" generators to direct them to reduce or cease generation). For further explanation, see Chapter II.
customer-side resources	Energy resources that are sited on the customer side of the utility meter and provide electricity for a portion or all of that customer's electric load. See also "Demand-Side Resources."

day-ahead market	The day-ahead market produces the schedule and financial terms of energy production and use for the operating day. It allows participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time.
demand response	Reductions in customer demand for electricity in response to grid conditions. Most demand response is temporary and done at the request of a utility or third party, which pays the customer for temporarily reducing their load. Some demand response is permanent in that the customer shifts their electricity use from periods of high demand to times when demand for electricity is low.
demand-side resources / demand-side programs	Electricity generation technologies that are sited on the customer side of the utility meter and provide electricity for a portion or all of that customer's electric load.
dispatchable (generation)	Refers to sources of electricity (e.g., natural gas power plants) that can adjust their power output in real time to respond to market conditions or at the request of grid operators.
distributed energy resources (DERs)	Generic term used to refer either to demand-side resources or distributed generation. (See definitions for demand-side resources and distributed generation.)
distributed generation (DG)	Distributed generation is a parallel or stand-alone electric generation unit generally located within the electric distribution system at or near the point of consumption (R.04-03-017). Distributed resources can be owned by an electric utility, a customer, or a third party.
distribution system	The network of wires with a voltage of less than 250 kV that distributes electricity to the majority of retail customers. Each distribution network is owned and operated by an individual utility.
duck curve	A collection of net load curves illustrating the net load curve for the same 24-hour period over the years 2012-2020. The CAISO modeled several future years of the same 24-hour period to illustrate the change in daily net load curve in future years as higher levels of wind and solar generation are integrated into the electric grid operated by the CAISO. In certain times of the year, these curves produce a "belly" appearance in the mid-afternoon that quickly ramps up to produce an "arch" similar to the neck of a duck—hence the industry adopted term of the "duck curve."
dynamic rates	A form of retail rate in which the customer is charged variable amounts related to the current cost of electricity. (See also TOU rates.)
economic curtailment	See "curtailment."
effective flexible capacity (EFC)	A generating resource's EFC is derived from its Net-Qualifying-Capacity and is a measurement of the resource's ability to ramp or sustain output for a 3-hour period of time.
energy efficiency	Energy efficiency refers to reductions in customer energy consumption by use of technologies which provide the same service using less energy (e.g., LED light bulbs, which provide the same amount of illumination as an incandescent or fluorescent bulb but use fewer kW).

Federal Energy Regulatory Commission (FERC)	FERC regulates the function of wholesale electricity markets in the United States (except for Texas) and regulates the operation of regional balancing authorities, such as the California ISO.
fleet	See "generation fleet."
flexibility	As used in this paper, flexibility refers to the ability to respond to changes in load, variable generation output, and/or generator outages on various timescales to assist the system operator in maintaining the operational reliability of the power system.
flexible capacity, flexible resource adequacy	Resources that can provide operational flexibility for the power system because of their ability to ramp up over a relatively short time period. "Flexible capacity need" is "the quantity of resources needed by CAISO to manage grid reliability during the greatest three-hour continuous ramp in each month." Also, resources are considered flexible capacity "if they can sustain or increase output, or reduce ramping needs, during the hours of the ramping period of flexible need" (D.14-06-050).
Flexible Resource Adequacy Must-Offer Obligation (FRAC-MOO)	FRAC-MOO is the "must offer" obligation in CAISO's tariff related to flexible RA resources. See also "must-offer obligation."
electric generation fleet/ generation fleet	The electric generation fleet includes all existing facilities/resources capable of generating electricity and delivering it to the grid. May also include resources that can store power and discharge it to the grid (called "non-generating resources" by CAISO).
grid reliability/ reliability	NERC's traditional definition of "reliability" consists of two fundamental concepts: adequacy and operating reliability. Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components. Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.
Integrated Energy Policy Report (IEPR)	The IEPR is a biennial report adopted by the CEC in compliance with Senate Bill 1389 to "conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices. The Energy Commission shall use these assessments and forecasts to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety" (Pub. Res. Code § 25301(a)).
independent system operator (ISO)	Formed at the direction or recommendation of the Federal Energy Regulatory Commission, an ISO is responsible for operating the electrical power system in an established area (see also "California Independent System Operator").

least-cost, best-fit (LCBF)	LCBF criteria are established in the RPS statute. They require utilities to evaluate and rank new renewable energy projects based on their net market value, using a LCBF methodology. Net market value is the generation, transmission, and integration cost of the project minus the energy and capacity value that it provides to the electricity system, which measures the project's "fit" with the system. For example, the LCBF approach should, over time, reflect the decreasing value of solar PV by favoring other renewable resources that may have higher costs, but generate more value.
load-following (resources)	Resources that can quickly ramp production up and down to follow changes in load throughout the day.
load-modifying program	A demand-side program intended to alter energy demand or load.
loading order	The California Energy Action Plan, which defined California's official energy policies, created a "loading order," which states that electricity demand should first be met by "cost-effective energy efficiency and demand reductions," then by renewable generation, then by traditional generation. Hence, energy efficiency and demand response are first in the loading order, and renewable generation is second. Because these technologies are higher in the loading order than traditional generation, they are referred to as "preferred resources."
locational benefit	The benefit to a small, local area of the electric grid, such as a distribution feeder, of a distributed resource.
manual curtailment	See "curtailment."
must-offer obligation	An obligation held by certain RA resources to make themselves available via economic bids into CAISO's wholesale electricity market. These obligations are codified in the CAISO tariff.
"N-1" reliability calculations	NERC Reliability standards based on ensuring the electric grid can recover from the sudden loss of generating and/or transmission resources. These standards are commonly used in transmission planning. An "N-1" condition is the loss of one resource and an "N-2" is the simultaneous loss of two resources. An "N-1-1" is the loss of one resource followed by the loss of another resource after 30 minutes (the time allotted for the system to recover from the initial "N-1" to prepare for another possible resource loss). The standard is usually tested by modeling the loss of the single largest generation or transmission asset.
net energy metering (NEM)	NEM is a customer tariff that provides a retail bill credit to utility customers with eligible renewable generation systems that deliver surplus energy into the utility grid.
net load	As used in this paper, net load refers to the residual electricity demand not met by wind and solar generation, i.e. total electricity demand for a specific time period minus the total wind and solar generation for the same time period. Alternative definition (not used in this paper): the difference between forecasted load and expected electricity production from variable generation resources.

non-generating assets/ non-generating resources	As defined by CAISO, non-generating resources include "Limited Energy Storage Resources" and "Participating Loads" acting as "Dispatchable Demand Response." See www.caiso.com/Documents/Non-GeneratorResourceRegulationEnergyManagementImplementationPlan.pdf. See also, "storage."
operational flexibility	See "flexibility."
peak load	The highest load experienced by the electric system, typically occurring during the hottest late summer days in California. CAISO's historic system peak load was 50,270 MW, which occurred on July 24, 2006 at 2:44 pm.
power system architecture	Refers to the configuration and operation of the system required to produce and deliver electricity. This system is composed of three sub-systems: generation, transmission and distribution. It has four operational entities: the power plant operator, the transmission operator, the independent system operator and the distribution system operator. Within each of these sub-systems, the system architecture describes the array of data sensors, controls and management devices used to sense grid condition, manage faults and manage voltage and frequency of the delivered electricity. In the future, the system architecture may include sub-systems used to manage distributed energy resources and other functions required to produce and deliver safe and reliable electricity based on distribution system assets.
preferred resources	See "loading order."
pumped storage/ pumped hydro	A hydropower resource where water is pumped between two reservoirs to then generate electricity when the water flows (by gravity) the lower reservoir. Typically, the pumping is done when electric rates are low, and power is generated when electric prices are high.
ramping / ramping event	Generally refers to the rapid need for an adjustment of generator output. Technically ramping is any change of electrical output measured over a certain period of time (and expressed as a Δ of MW/minutes or hours).
real-time market	An energy market that uses final day-ahead schedules for resources within the ISO and final hour-ahead schedules for imports and exports as a starting point. It then re-dispatches energy resources based on their bids every five minutes to balance generation and loads.
renewable portfolio standard (RPS)	RPS refers to the "specified percentage of electricity generated by eligible renewable energy resources that a retail seller or a local publicly owned electric utility is required to procure" (SB 350 SEC. 18(i)).
renewable integration adder / renewable integration cost	The renewable integration adder (required by AB 2363) reflects the costs of integrating renewable resources onto the grid, which are levelized and expressed in terms of dollars per megawatt-hour ($/MWh).

Resource Adequacy (RA)	The Resource Adequacy program has two goals. First, it provides sufficient resources to the California Independent System Operator to ensure the safe and reliable operation of the grid in real time. Second, it is designed to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future. The Basics: The CPUC adopted a Resource Adequacy (RA) policy framework (Pub. Util. Code section 380) in 2004 to in order to ensure the reliability of electric service in California. The CPUC established RA obligations applicable to all Load Serving Entities (LSEs) within the CPUC's jurisdiction, including investor owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs). The Commission's RA policy framework – implemented as the RA program – guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO when and where needed.
Rule 21-Interconnection	For entities under the CPUC's jurisdiction, Rule 21 governs the interconnection of distributed energy resources (DERs) such as solar PV, energy storage, and non-inverter based synchronous generators. Rule 21 applies to all interconnecting DERs under 20 MW that do not plan on participating in wholesale markets. Rule 21 is largely based on IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems," and lays out the design requirements for DERs as well as the process by which prospective DERs apply and are studied for interconnection to the distribution grid.
smart inverters	Smart inverters build on basic inverter functionality (converting DC to AC power) by autonomously adjusting or modulating distributed energy resource power output to serve a localized grid balancing function, and can communicate with IOUs, aggregators, or market operators for purposes of system monitoring and control. Smart inverters have the potential to contribute to system-level flexibility and reliability and assist with grid integration.
Storage/energy storage system	As defined by AB 2514, "energy storage system" means commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy. Pub. Util. Code §2835(a) expands on the desired and required characteristics to qualify as a storage system.
supply-side resources	Generally, these are resources interconnected with the transmission grid that participate in the wholesale energy market, and were traditionally large-scale generation resources. This distinction is currently evolving.
time-of-use (TOU) rates	Retail electric billing rates which vary based on the time of day, week, or year. Time of Use (TOU) rates and dynamic rates are two varieties of time-variant pricing for electricity. TOU rates charge fixed rates at fixed periods that roughly correlate with the high (peak) and low (off-peak) cost hours of procuring energy throughout the day. (See also dynamic rates.)
transmission system	The system of high voltage electric lines (250 kV and above) that interconnects the wholesale power grid in California. This paper is generally concerned with the transmission system operated by CAISO.
utility-scale resources	See "supply-side resources."

variable (renewable energy) energy resources/ variable resources	Those resources that can generate electricity only when wind and solar resources are available. Their energy output is subject to both variability and uncertainty, which fluctuates from moment to moment in a manner that is not entirely predictable.
vehicle-grid integration (VGI)	VGI uses transportation electricity as a system resource that accelerates Zero-Emission Vehicle adoption and hastens their associated environmental benefits. VGI harnesses plug-in electric vehicle usage characteristics and technologies to provide storage and demand response to integrate renewable energy in a manner that maximizes the vehicles' value to drivers (by reducing fuel or capital costs) and the grid (by reducing infrastructure and maintenance costs borne by utility customers).
wholesale energy market (wholesale market, or energy market)	Generally refers to the electricity market operated by CAISO for the majority of electricity sold in California. Includes a competitive day-ahead and real-time platform for generators to submit bids and be dispatched when the market clears above their bid price. Not all resources bid into the market, rather, many resources are "self-scheduled" or are "must take."