DOCKET
11-IEP-1D
DATE
RECD. NOV 09 2010

DRAFT STAFF PAPER

INFRASTRUCTURE NEED ASSESSMENTS FOR THE *2011 INTEGRATED ENERGY POLICY REPORT*

Reconciling Policy Goals With Reliability Constraints

Michael Jaske and David Vidaver

Electricity Analysis Office

Electricity Supply Analysis Division

California Energy Commission

DISCLAIMER

This paper was prepared by a member of the staff of the California Energy Commission. As such, it does not necessarily represent the views of the Energy Commission or the State of California. The Energy Commission, the State of California, its employees, contractors, and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this paper; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This paper has not been approved or disapproved by the California Energy Commission nor has the Commission passed upon the accuracy or adequacy of the information in this paper. This paper has not been approved or disapproved by the full Commission.

NOVEMBER 2010

CEC-200-2010-010-SD

TABLE OF CONTENTS

Page

LIST OF TABLES

Abstract

This paper outlines an assessment of new infrastructure needed for California's electricity sector to be undertaken for the *2011Integrated Energy Policy Report*. It introduces and defines terminology, and enumerates the planning elements for which an infrastructure assessment might be conducted. It then discusses the staff proposal for the *2011 IEPR*, potential sources of data for analysis, and the manner in which uncertainty in input values will be considered. Finally, the coordination of this effort with those being undertaken at the California Public Utilities Commission and the California Independent System Operator is discussed. An appendix contains a description of the components of the assessment and sources of data to be used.

Keywords: Electricity infrastructure, integrated resource planning, need assessment, need conformance, uncertainty, reserve margin, energy efficiency, transmission, transmission constraints, local capacity requirements, once-through-cooling, South Coast Air Basin, intermittent generation, dispatchability

Please use the following citation for this report:

Jaske, Michael, David Vidaver. 2010. *Infrastructure Need Assessments for the 2011 Integrated Energy Policy Report – Reconciling Policy Goals With Reliability Constraints*. California Energy Commission. CEC-200-2010-010-SD.

EXECUTIVE SUMMARY

The *2009 Integrated Energy Policy Report (IEPR)* and subsequent discussions with other agencies since its publication have highlighted the desire to translate loose energy policy preferences, established first in the *2003 Energy Action Plan,* into a more specific vision for a future California electricity system that encompasses not only the preferences but also reliability requirements mandated both by common sense and by standards set by the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council.

An interagency "vision" and several supporting documents have recently been published as the *California Clean Energy Future*.[1] Questions that must now be addressed include:

- What are the specific infrastructure elements that the electricity industry, guided by state policy and law, must put in place to achieve this vision? For example, what is the blueprint corresponding to this vision?
- Assuming the preferred policies develop as desired, what are the complementary infrastructure needs that satisfy reliability requirements?
- How can these be specified by resource type and location?
- Given uncertainties about achieving policy objectives, and other developments outside California policy makers' control, how might infrastructure needs vary?

This white paper provides California Energy Commission staff's proposal to implement, for the *2011 Integrated Energy Policy Report,* an electricity infrastructure need assessment project that will attempt to answer these questions analytically. This effort will build upon the existing infrastructure need assessment capabilities that are known to exist within the principal state energy agencies such as the California Public Utilities Commission, the California Independent System Operator, and large utilities. The *2009 IEPR* recommended developing a quantitative capability to express infrastructure need at the Energy Commission that also draws upon the expertise of the other energy agencies.

The *2011 IEPR* is the first step in which the Energy Commission will reintroduce some version of infrastructure need assessment into the IEPR proceeding. [2] This effort will focus on the portion of electricity infrastructure served by central station power plants and the bulk transmission system. Although distributed generation – small scale generation located close to where electricity is used – is a promising approach, staff's methods do not allow, at this time, a complete assessment of distribution impacts of various distributed technologies and the "smart

1 http://www.climatechange.ca.gov/energy/index.html.

2 The *2005 IEPR* included an explicit need assessment for the bundled customers for each of the three investor-owned utilities. These results were communicated to the California Public Utilities Commission for use in the 2006 Long Term Procurement Plan proceeding through a separate Transmittal Report prepared in the fall of 2005. Unlike that contract-based need for bundled customers, this effort emphasizes the physical need for additional generating resources.

grid" controls to allow these generation technologies to substitute for central technologies. Depending upon progress made in this initial effort, further improvements will be made in subsequent *IEPRs*, allowing staff to improve its existing capabilities and allowing for increased coordination among other energy agencies.

The results of this need assessment can serve multiple purposes. First, by examining a range of future assumptions, the sensitivity of need to such assumptions can be understood more directly than in rhetorical discussions. For example, how does the degree of success in meeting Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) energy efficiency goals translate into differences in need for power plant development? Second, developers of generation and transmission projects can see a coherent view across balancing authority areas, local areas, and functional purposes for project development. For instance, when owners of existing power plants subject to the State Water Resource Control Board's once-through-cooling mitigation policy evaluate whether to retire or repower those plants, what operating characteristics should be designed into a repowered facility to best meet future system needs? Third, the Energy Commission's power plant licensing staff can better understand how projects under the Energy Commission's licensing jurisdiction match up to estimates of future system needs. For example, how should the Energy Commission consider a power plant proposed to be built that is not flexible in operating characteristics and is not located in a local capacity area with resource needs?

This paper includes several sections. Section I introduces the topic and provides definitions and a basic understanding of need assessment using examples. Section II enumerates various planning elements for which an infrastructure addition assessment might be conducted, and where needed improvements are apparent. Section III provides Energy Commission staff's specific proposal. Section IV discusses the relationship of this need assessment proposal to the activities now underway at the California Public Utilities Commission and the California Independent System Operator, which may be a source of inputs but which are also possible forums for which this need assessment can be perceived as duplicative. Section V discusses uncertainty, which will affect the assessment efforts. Section VI discusses various purposes and dimensions of infrastructure addition assessment that must be established in order to define the precise effort. Finally, Section VII provides a conclusion and proposes some next steps.

Section I: Introduction

Discussion of visions, blueprints, infrastructure need assessment and related concepts can become bogged down in terminology differences. This paper uses the following definitions from Chapter 3 of the *2009 Integrated Energy Policy Report (IEPR)*:

- **Vision:** A view of the future electricity system incorporating the preferred policy elements (renewable generation, demand-side initiatives) and supporting infrastructure (transmission, smart grid, distribution components) that both achieve greenhouse gas (GHG) emission reductions goals and assure reliability standards.
- **Blueprint**: A semi-quantitative plan, guide, or framework that translates the vision by juxtaposing resource policy preferences against reliability standards and resolves conflicts. It reflects priorities among policy preferences where they interact or conflict, indicates which entities are guided by the plan, and establishes how agencies coordinate with one another. A blueprint provides the basis for developing detailed plans.
- **Need assessment:** A process of quantitatively evaluating the state's blueprint using current and expected electricity demand, new supply additions, possible retirements of existing power plants, operating requirements, and necessary transmission to guide decisions about the future energy system mix, to determine the necessary attributes and locations of needed power plants and transmission lines, and in what time frame.
- **Need conformance:** The process of determining whether the expected operation of a specific plant matches the planning elements in a previously developed need assessment.

Clearly this particular set of definitions interrelates the four terms, with each succeeding term building upon the previous terms. For purposes of this paper, then, need assessment is the third step in a progression of thinking that starts with a vision for a future electricity system, moves to a blueprint calling out specific tangible elements and features that implement the vision, and, finally, to a quantitative process called "need assessment" that determines what increments of electricity infrastructure are necessary to get from the current system to implementing the blueprint for the future system.[3] The term "need assessment" has been around a long time, means different things to different communities within the electricity industry, and can create visceral adverse reactions. Unfortunately, staff has devised no suitable replacement, and the term will be used as defined above.

3 This paper will not dwell on the fourth term – need conformance – but in an industry structure with some competitive market elements, it should not be surprising that some players will propose to develop infrastructure components that may not be compatible with the vision. Need conformance is a general term for a process that compares project proposals with the needs identified in a need assessment process. One option is to screen out proposals that do not match needs, but this is only one option. Even for this option there are many means by which such "screening" might take place.

Section II: Planning Elements

What Are Infrastructure Additions and How Are They Determined?

At its core, infrastructure need is the amount of a particular type of infrastructure (for example, dispatchable generation, transmission capacity) necessary at some specific time to satisfy reliability requirements under a given set of assumptions about the future. The amount of a specific category of infrastructure that is needed is determined by comparing a particular future system requirement against current expectations about what resources will be available.

The vision describes the future electricity system that is desired. The blueprint turns that vision into sufficiently specific requirements that such a system can be assessed quantitatively. The infrastructure need assessment quantifies the differences between the existing system and the future system for one or more future years under a given set of assumptions. Since the future is uncertain and multiple futures may be realized, infrastructure need assessments should reflect ranges of needed investment and should be dynamic, evolving with better understanding of future uncertainties and actual investment commitments. Further, looking across a range of alternatives, decision makers should be focused on identifying "no regrets" investments that can – and frequently must be – undertaken immediately.

A simple example may be useful. One portion of the California Clean Energy Future (CCEF) vision imagines a future in which 33 percent of electrical energy consumed in California is provided by renewable generation by 2020. During 2010, the California Transmission Planning Group (CTPG) effort has attempted to identify transmission line additions and/or upgrades needed to allow 33 percent renewable generation to be deliverable to load. The CTPG effort could be thought of as developing a number of alternative blueprints for achieving 33 percent renewable goals and then evaluating each of them for the conceptual transmission additions that must be made. Given existing renewable resources, and those now in the development pipeline that are expected to be constructed for each scenario, we can calculate the transmission component of "needed infrastructure" to satisfy the vision as translated by a particular blueprint option. A different interpretation of the vision would lead to different set of infrastructure needs. Each of these interpretations of the vision must be evaluated to identify the complementary fossil generation resources that are needed to satisfy either renewable integration or basic reliability requirements.

How Would the Need for Infrastructure Additions Be Estimated?

The details of staff's proposal for future electricity system elements that would be evaluated in an infrastructure addition assessment – how geographically granular this should be and how far into the future is necessary – are specified in Section III. Ideally, the following elements will be calculated for each balancing authority area going out 10 years to 2022:

- System capacity to cover peak load (with reserves for contingencies) by balancing authority area (BAA)
- Local capacity requirements within BAAs
- Operational requirements (ramping, RegUp, RegDown, and so forth.)
- Energy requirements with energy reserves
- Transmission to satisfy reliability standards and other policy goals (low cost, preferred resource choices and locations).

The extent to which this set of elements can be calculated for each BAA depends upon full access to existing studies, other studies known to be in progress but not completed, and perhaps upon explicit data requests to utilities and transmission owners.

As an example, the equation below has been traditionally used to calculate the amount of general capacity necessary to satisfy expected peak demand in the California Independent System Operator (California ISO) balancing authority area in a seven-year-ahead future.

$$\begin{aligned}\text{Capacity Additions}^{2017} = \quad & \text{Peak Demand}^{2017} * \text{Planning Reserve Margin} \\ & - \text{Existing Capacity}^{2010} \\ & + \text{Retirements}^{2010\text{-}17} \text{ [expected under existing policies]} \\ & - \text{Additions}^{2010\text{-}2017} \text{ [expected under existing policies]}\end{aligned}$$

Generically, this equation identifies the total amount required less the amount that exists today, adjusted for the capacity value of resources expected to retire and resources expected to be developed. The caveat "expected under existing policies" is an extremely important qualifier that will be discussed further in the next section. It suggests that "existing policies" have consequences that impact resource additions and resource retirements. This basic equation tells us how much additional capacity has to be brought on line to serve expected peak load under the set of conditions covered by a planning reserve margin. Once the basic infrastructure addition equation is defined, it can be applied to a host of elements that the system should possess, and numerous layers of refinement can be added.

The simple equation discussed above may not sufficiently address the complexities of the future electricity system, especially one with large proportions of energy produced by intermittent renewables. Due to their intermittency, such generating technologies require supplemental resources to supply load when the intermittent resource is not generating power (or to supply reserves when it may not be generating power). One interpretation of this phenomenon is that the planning reserve margin must increase from the current range of 15-17 percent adopted by the CPUC for resource adequacy purposes to some higher value. Another interpretation is that the supplemental resources that must be added are themselves flexible to operate in ways complementary to intermittent renewables, but such capacity only displaces older, less flexible generation. Both interpretations might be correct. Staff's proposal in Section III can accommodate both an increasing reserve margin and the need for amounts of flexible generating capacity increasing along with renewable generating capacity.

Why Is "Expected Under Existing Policies" Important?

The basic infrastructure need equation includes adjustments based on resource development and resource retirement that are qualified as "expected under existing policies." Two obvious questions arise:

- Why should retirement and resource development be included in infrastructure addition assessment?
- What is meant by the qualifier "Expected Under Existing Policies"?

Retirement and resource development adjust for changes in resources resulting from the passage of time between the future year of interest and the current resources "on the ground" in a base year. Existing power plant retirements reduce capacity and associated energy production, and such reductions may require replacement. Retirements may be in the pipeline scheduled for a specific year, linked to development of a replacement facility, or tied to other conditions obviating the benefits of the facility. Similarly, new resources are being developed that will not be operational for a number of years. A power plant may have been licensed, a power purchase agreement with an LSE secured, and the start of construction imminent. The power plant does not become operational, and thus reduce necessary infrastructure additions, until it is constructed, tested, interconnected to the grid, and accepted for commercial operation. This requires several years in most instances.

The qualifier "expected under existing policies" is a crucial limit on the analyses conducted to determine retirements or resource development expectations. It means that the analyst has the obligation to identify existing policies, assess how they may affect retirement or development, look for interactions among multiple policies, and ascertain how the outcomes differ according to uncertainties in key assumptions. While this clearly involves some subjective components, conducting this evaluation is critical. For example, there are numerous power plants that have already obtained Energy Commission permits but do not have power purchase agreements. Should none, some, or all of this capacity be assumed to be constructed? The more of this already permitted capacity that is assumed to be constructed, the less additional capacity will be needed in the same period. Another way to express this line of thinking is to describe the basic need equation as computing "net" need, not "gross" need. Net need is that amount of infrastructure addition that still must be identified as opposed to some other resource additions that are already firmly committed.

Individual Agency Processes Conducting Infrastructure Need Assessment

As noted throughout this paper, a variety of agencies and organizations already rely upon something that resembles "infrastructure need assessment " to carry out their missions, although they may not use this specific terminology. In some instances, these agencies are making plans to upgrade their assessments to take into account one or more developments that require better assessments. The CCEF draft implementation plan provides considerable information about the current planning proceedings, how they interact with one another, and offers some discussion about collaboration opportunities. **Table 1** briefly lists the current processes encompassing infrastructure addition assessments in some form, improvements now underway, and staff's determination of compatibility with this proposal.

The Energy Commission and the California ISO conduct infrastructure need assessments for generation capacity for the "summer ahead." Studies focused on capacity are the most publicly visible components among current agency practices, an outgrowth of the Electricity Crisis of 2000— 2001. The California ISO conducts an assessment of local capacity area (LCA) requirements that is then used within the current resource adequacy processes that it and the California Public Utilities Commission (CPUC) have adopted for load serving entities (LSE) within the California ISO BAA. It differs from the more general infrastructure need assessment in several important ways. First, it establishes a minimum amount of capacity that must be secured by utilities within specific local areas, for example the Greater San Francisco Bay Area, and the Los Angeles Basin. Second, the time frame is only one year ahead, so the focus is on securing existing resources by contract, not identifying the amount of new capacity that must be added in the LCA. Third, engineering studies – using power flow and stability models and not the simple accounting used in planning reserve margins – establish these LCA requirements. Such studies can detect more subtle interactions between specific generating capacity on-line and upgrades to the transmission network. The California ISO also conducts LCA studies 5-years forward, but it characterizes the results as "for information only," and these studies don't factor into any specific generation or transmission planning decisions.

In its 2011 Long Term Procurement Plan rulemaking, the CPUC is conducting two parallel assessments. First, it is planning to authorize the three investor-owned utilities (IOUs) to procure sufficient resources to satisfy projected bundled customer loads out about seven years. Second, it is undertaking a "system" assessment for new resources that are needed to satisfy the IOU service area loads and other reliability requirements. The latter is a physical system assessment. [4]

4 Although this is a physical system assessment, it differs from the Energy Commission staff proposal described in Section III of this white paper. The sum of the three IOU "system" needs will not match that for the California ISO, because the CPUC "system" excludes embedded municipal loads and associated resource requirements. The Energy Commission staff proposal will conduct analyses for the entire California ISO balancing authority area, including IOUs, other regulated load serving entities, and POUs.

Table 1: Agency Processes Performing Infrastructure Addition Assessment

Agency	Process	Use of Infrastructure Need Assessment in Current Process	Changes Made Recently or Under Discussion
CEC	Annual staff report	Informational briefings to Governor and Legislature.	Shift from "summer ahead" to 5-Year Outlook for capacity requirements for state/regions.
	Biennial IEPR	No formal role, but infrastructure addition assessment techniques used to illustrate consequences of OTC retirement and SCAQMD air credit shortages in *2009 IEPR.*	*2009 IEPR* directed the establishment of a formal infrastructure addition assessment as part of IEPR; role could be advisory for general planning purposes or linked to "need conformance" for specific power plant proposals.
CPUC	Biennial LTPP	Establishes bundled customer needs 5-7 years into the future; authorizes IOU procurement.	R.10-05-006 establishes "system" infrastructure addition assessment to replace ad hoc directives to IOUs to construct new capacity.
	Resource Adequacy	Uses California ISO LCR studies to determine LSE local capacity requirements.	Final decision in R.05-12-013 proposes agencies collaborate to extend forward horizon out 5-6 years to identify new resources "needed".[5]
California ISO	Annual TPP	Establishes "need" and "need conformance" for specific transmission projects.	Broaden justification from just reliability and economics by adding "delivery of renewable energy to load" as a rationale.
	Local Capacity Studies	Establishes amount of capacity that must be available to system operator within local areas.	Broaden range of assumptions used in assessments; extend them further into the future; use them for policy evaluations like OTC retirement scheduling.

Source: Energy Commission Staff

The California ISO transmission planning processes have been the most publicly visible efforts, although the CTPG effort that began in fall 2009 has increased the visibility of publicly owned utility (POU) transmission planning. In the transmission planning community it is not as common to describe a generic need, and thus to separate assessment from conformance, since transmission is less easily described in generic terms. In the traditional transmission planning process, specific projects are evaluated for their benefits in reducing congestion (economic justification) or solving tangible reliability problems (thermal overloads of specific lines, voltage issues, stability issues, and so forth) that arise during periods of high loads or system

---

5 CPUC D.10-06-008, issued June 3, 2010, determines that multi-year need assessment should be undertaken on a collaborative basis by CPUC, Energy Commission, and California ISO. Pages 68, 70. To date, no specific discussions among the three agencies to implement this directive have been undertaken.

component failure. A specific project that relieves a given contingency may be effective in one future configuration of the transmission system, but not in another.

The CTPG's Phase 3 results, and the California ISO's own analyses, highlight transmission needed to support renewable development.[6] CTPG has identified more than 100 conceptual projects (new lines, existing line upgrades, and other component improvements) needed to support specific renewable projects in interconnection queues or generic projects in competitive renewable energy zones (CREZs) required to satisfy an expanded Renewables Electricity Standard goal of 33 percent by 2020. Each transmission planning entity intends to examine these conceptual projects more closely in its own individual planning process. Recognizing that conducting this effort using special studies was not satisfactory, the California ISO has recently proposed that renewable transmission assessments be merged into its traditional Federal Energy Regulatory Commission (FERC) Order 890 transmission planning process.[7] In some respects this reflects the "conditional" nature of the results, for example, merits of specific transmission lines are highly dependent upon the specific amount, location, and type of renewable generation development. Since the future for renewables cannot be pinned down with adequate certainty, scenarios examining multiple renewable buildout patterns provide a "conditional" basis for understanding the need for transmission development.[8] Scenarios developed as part of the Renewable Energy Transmission Initiative process are based on estimates of potential development in 30 or so "competitive zones" located both in and outside California. These estimates consider the "technical potential" and cost (including transmission and environmental impact) for development in each zone. The extent to which these estimates comport with actual and proposed, viable development remains unknown.

Finally, although renewable integration is currently receiving a great deal of attention, the methods for determining the amounts, types, and locations of flexible resources needed to accommodate the special characteristics of intermittent generation resources are neither standardized nor routinely incorporated into any of the energy agency planning processes. The California ISO has developed and presented methods for renewable integration analyses in workshops conducted as part of the current CPUC LTPP rulemaking.[9] Pacific Gas and Electric Company (PG&E) has developed a renewable integration model (RIM) seeking to augment traditional planning techniques.[10] The Energy Commission funded a study by KEMA, Inc., that

---

6 CTPG, Phase 3 Final Results, October 2010.

7 California ISO, Revised Transmission Planning Process: Complete Final Proposal, May 7, 2010.

8 California ISO, 2020 Renewable Transmission Conceptual Plan Based on Inputs from the RETI Process: Study Results, September 15, 2009.

9 California ISO, presentation at August 24, 2010 and October 22, 2010 LTPP workshops.

10 PG&E, presentation at August 25, 2010 and October 22, 2010 LTPP workshops.

also tackled these questions.[11] While the results of the California ISO, PG&E, and KEMA analyses differ in detail, they each show the need for more flexible resources as the proportion of intermittent renewables increase over time. Given these uncertainties about magnitudes actually needed, one possibility is that the CPUC's final 2010 LTPP decision will only authorize the IOUs to procure limited quantities of flexible resources.

Section III: Energy Commission Staff's Specific Proposal

Staff proposes to prepare a quantitative need assessment for electricity infrastructure covering all portions of the state and addressing quantities of generation needed at the balancing authority area and the major local capacity areas through 2022. This analysis would attempt to collect and use all available information to the calculations and include estimations or "best guesses" where necessary for variables considered to be important, but where statistical methods for addressing uncertainty cannot be implemented due to lack of data. Rather than duplicating analyses being undertaken in the CPUC's LTPP rulemaking or the California ISO forums, staff hopes to make use of the input assumptions being used in these other assessments as well as their results. The analyses would explicitly incorporate uncertainty for each input to the calculation as well as any uncertainties in the calculation itself. The uncertainties in input assumptions and methods for computing need would be shown as ranges of need in the final product.

Although conducted for all balancing authority areas, much of the attention will be focused on Southern California and the special issues associated with retiring old once-through cooling (OTC) plants, the difficulties of what portion of that capacity needs to be replaced with fossil generation, and the constraints on air credits inhibiting development of such facilities. In practice, these special problems for Southern California can be depicted as uncertainties with alternative implications for need based on the range of inputs assessed.

Staff proposes that a stand-alone document describing results and input assumptions be prepared according to the following sequence of steps: (1) initially prepared by staff, (2) reviewed by the IEPR Committee with input from participants from workshops and comments, (3) a revised staff draft document reflecting feedback and new information, (4) a draft final version reflecting IEPR Committee preferences, and (5) a final version would be adopted by the Commission as a supplemental report that is considered to be part of the *2011 IEPR*. From draft and Committee versions of this report, policy and analytical recommendations can be drawn and included in the main body of the *2011 IEPR* report. Staff imagines that the report would consist of a large number of tables for each balancing authority area and graphs showing the

11 KEMA, Inc., *Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid*, prepared for the California Energy Commission Public Interest Energy Research Program, CEC-500-2010-010, June 2010.

range of need along with associated descriptions of methods used and sources of inputs, including ranges of uncertainty for such inputs.

The following subsections describe various features of staff's proposal.

Descriptors For Which Need Will Be Assessed

Staff proposes to assess three descriptors of need described in geographic terms:

- Capacity need for the five BAAs located entirely within California
- Capacity needs for each major LCA within each BAA
- Transmission need within and between BAAs

BAA capacity need considers the simple capacity supply/demand balance that has been conducted in many forums. LCA capacity requirements are, at least at this time, simple capacity located in an LCA with a contractual agreement to satisfy California ISO availability requirements and to conform to California ISO unit commitment and dispatch instructions as needed for reliability purposes. Transmission needs are largely expected to be derived from generation development and retirement patterns.

To the extent possible, staff proposes to identify the amount of need for each type service necessary to reliably serve the electricity system. The best enumeration of these services has been presented by the California ISO in its renewable integration study preliminary results released in August 2010, for example, automatic generation control (AGC), ramping, spinning induced inertia, or simple dispatchable capacity. Although storage technologies can clearly support some forms of daily ramping, it remains unclear whether specification of system requirements and storage technology capabilities can be joined together successfully in this IEPR cycle.[12]

As described in Section V of this paper, these results will be expressed as ranges reflecting uncertainty in input assumptions and also in methods for computing results. The IEPR Committee may want to consider whether there is a lower value from this range of need results that can be safely used as "no regrets" level of resource development. It is also possible that different "users" of this need assessment will make their own decisions about how to make use of the range of need presented.

12 Assembly Bill 2514 (Skinner, Chapter 469, Statutes of 2010 requires the CPUC, by March 1, 2012, to open a proceeding to determine appropriate targets for load-serving entities to procure viable and cost-effective energy storage systems and, by October 1, 2013, to adopt an energy storage system procurement target for each load-serving entity by December 31, 2015, and a second target to be achieved by December 31, 2020. It also requires the governing boards of local publicly owned electric utilities to open a proceeding by March 1, 2012 to determine appropriate targets for procurement of viable and cost-effective energy storage systems and, by October 1, 2014, to adopt energy storage system procurement targets to be achieved by December 31, 2016, and a second target to be achieved by December 31, 2021.

Evaluation Time Horizon

The study time horizon is a critical element in the production of an infrastructure assessment. The near-term driving factors for infrastructure may become far less significant in the more distant future. Also, the construction lead time and investment repayment time will need to be considered when making infrastructure decisions today. Staff believes that existing methods are appropriate for time horizons out to 10–12 years. Future IEPR cycles might try to push out the time horizon to 20–25 years using specialized study techniques better equipped to handle the increasing uncertainty that exists that far forward.

Since there will be large quantity of information, key results for years 2017 and 2022 should be highlighted. The year 2022 reflects the furthest out year staff proposes to assess. The year 2017 is a convenient intermediate year that closely corresponds to the time horizon emphasized by the CPUC in the 2011 LTPP rulemaking.

Methods for Calculating Need

As noted earlier, the *2009 IEPR* discussion of the need for more complete and coordinated need assessments suggests that collaborative efforts are most likely to ensure the best information is used for any given variable. **Table 3** on page 20 provides a listing of the principal variables staff proposes to use in its need assessment, and what staff considers to be the best source for that variable. The basic calculation methods and discussion of sources are spelled out in more detail in Appendix A – *Inputs and Sources for Calculating Infrastructure Needs*. Key questions outlined there will guide preparation of a stand-alone report from which policy and further analytical recommendations can be drawn and included in the main body of the final *IEPR*. This report would attempt to apply all available information to the calculations and include estimates or "best guesses" where necessary. This report would both demonstrate the staff's specific method for identifying need using multiple perspectives, and an exploration of the current limits of staff's knowledge. The document would explicitly discuss the difficulties and sources of uncertainty for each input to the calculation as well as any uncertainties in the calculation itself. This end product would act as a first step toward refining the methodologies and inputs necessary to produce a useful assessment of infrastructure needs.

Table 3 is organized as follows:

- The leftmost column identifies the principal elements for which a need assessment will be calculated, for example, system capacity by BAA, local capacity for most critical local capacity areas within BAAs, and so forth.
- The second column from the left provides a description of the equation proposed for computing need.
- The third column from the left enumerates the variables needed for the calculation.
- The rightmost column identifies the best source for each variable.

Four important observations about **Table 3** should be made. First, renewable generation requires flexible resources, but the types and amounts are poorly understood. No formally accepted methods for computing the required quantities of the operating characteristics exist.[13] It is not completely clear whether the nature of the needed characteristics match the design of the current market.[14] Three major studies have contributed information about these requirements,[15] but no definitive method yet exists, and the amounts required are not now calculated within any of the existing electricity planning processes conducted by the energy agencies. A qualitative description of the necessary infrastructure addition for dispatchable generation (currently understood to mean fossil power plants) was developed as a contractor report for the Energy Commission, and this is being used within individual Energy Commission siting cases to develop the record for such needs.[16]

Second, transmission infrastructure assessments are very difficult to separate from transmission need conformance. Traditional transmission assessment mainly evaluates the costs and benefits of specific system elements that alleviate thermal overloads or stability concerns during system contingencies. Unlike generation infrastructure need assessment, such transmission "solutions" are very specific as to size and configuration, linkages between existing elements of the transmission system, and to particular stylized stressed conditions for the system (load levels, operating patterns for the generating fleet, and outages of existing elements of the transmission network). These traditional concerns have focused transmission assessment on need for a specific project. In contrast, generation infrastructure addition assessment is frequently conducted in a way that multiple projects could readily satisfy the need for infrastructure addition that is determined to exist.[17] The recent recognition of the new third category of

---

13 The California ISO analysis of resources required to integrate renewables can be considered to be at the "proof of concept" stage. It is unclear whether all aspects of integrating renewables into the electricity system have been thoroughly examined. The analysis has not been conducted in a "production" environment in which all inputs, methods, and results have been thoroughly exposed to scrutiny.

14 For example, with solar central resources a predictable pattern of increasing production in the morning hours and decreasing production in the evening hours motivates the need for "load following" resources that expect to be operated to complement solar production, There is no "load following" product as part of the current California ISO market, so each dispatchable generator would have to bid into the integrated forward market a set of 24 values with no direct linkage from one hour to the next.

15 California Energy Commission Public Interest Energy Research Program's programs Intermittency Analysis Project completed in 2007, the California ISO's 2007 study of 20 percent renewable integration requirements, and the California ISO's current study of 33 percent renewable integration requirements.

16 California Energy Commission, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report prepared by MRW, CEC-700-2009-009, May 2009.

17 The current CPUC-approved procurement process depends upon multiple bidders responding to IOU Requests for Offers to mitigate possible market power. IOUs select a "short list" of bidders for increased scrutiny, and sometimes allow refreshed bids before selecting winning projects. This process inherently assumes more than one project can satisfy need.

transmission – delivering renewable generation to load centers – is assessed at a conceptual level more analogous to generation infrastructure addition assessment. Various hypothetical amounts and locations of renewable development create the "need" for different transmission upgrades. The choice of whether to pursue such upgrades is likely to hinge upon the overall cost of the renewable development combinations and their associated transmission system upgrades across a variety of possible renewable development patterns.

A third observation is that sources of information for this assessment generally focus on the entities under the regulatory oversight of the CPUC. The CPUC's direct ratemaking control for IOUs and its numerous interactions with the California ISO have resulted in far greater scrutiny and public processes to sunshine information than for the smaller POUs embedded within the California ISO BAA or the larger POUs that operate their own BAA (Sacramento Municipal Utility District/Western, Los Angeles Department of Water and Power [LADWP], Imperial Irrigation District, and Turlock/Merced). The emergence of the CTPG may increase visibility of some transmission planning efforts for the POUs, but many aspects of what studies are conducted and public access to the study results are still very opaque. Staff will depend on the cooperation of POUs in acquiring the information needed to complete this effort for the POU BAAs.

Finally, the analytic methods for computing need that staff can successfully implement in this IEPR cycle are limited to those that evaluate central station power plants and bulk transmission systems. While distributed generation has attractive properties, for example, avoiding most transmission system upgrades by locating the source of generation very close to load, staff is not capable of quantitatively assessing the "cost" side of DG development. The need for distribution system upgrades, the need to achieve at least some portion of what is called "smart grid" capabilities to integrate local generation into distribution circuits are "costs" that can be discussed in qualitative terms but cannot be quantified at this time in the same manner as centralized generation and bulk transmission. Although technical issues and needed analytic developments can be identified, actual progress in quantitatively assessing the full range of distributed generation impacts (both costs and benefits) requires more time than possible in this *2011 IEPR* cycle.

Table 2: Possible Elements for System Infrastructure Addition Assessment and Sources of Inputs

Element	Simplified Description of Infrastructure Addition Assessment	Necessary Inputs	Best Source[18]
Generation			
System Capacity by balancing authority area	(1:2 Peak Forecast – demand-side policies initiatives)* (1 + PRM) less current resources less expected resource development under existing policies plus expected retirements under existing policies	1:2 peak demand forecast	ESAD/DAO efforts for the 2011 IEPR with *2009 IEPR* results as backup
		Base year resources	CPUC NQC database for 2011 is likely starting point, but needs some POU resources added
		Incremental EE	CEC 2010 Inc-Unc report and updates for the 2011 IEPR are likely sources
		Incremental self gen/CHP	CEC ICF study and the multi-party QF settlement of October 2010
		Incremental DG	Renewable scenarios from 2010 version of the CPUC/ED RPS calculator
		DR	CPUC/ED projections from Scoping memo for 2011 LTPP
		PRM projections[19]	15-17 percent remain valid since CPUC terminated its PRM OIR
		Known/firm fossil additions	Various sources to track actual progress of a limited number of facilities
		Renewable additions	Renewable scenarios from 2010 version of the CPUC/ED RPS calculator
		Non-OTC retirements	Some limited speculation exists about old steam boiler facilities
		OTC retirements	SWRCB OTC compliance schedule is one component, but there are numerous other plant/unit-specific dates

18 The CPUC adopted R.10-05-006 (the 2010 Long Term Procurement Plan) on May 6, 2010. The CPUC/ED Planning Standards for System Resource Plans, released as Attachment 2 of ALJ Kolakowski's May 28, 2010 ALJ ruling identifies this list and suggested sources.

19 Planning reserve margin (PRM) establishes a further increment of capacity that is necessary to cover power plant outages and uncertainty demand. The California ISO published its final assessment pursuit to CPUC R.08-04-012 on May 21, 2010.

Element	Simplified Description of Infrastructure Addition Assessment	Necessary Inputs	Best Source[18]
		Imports and exports	Long-term contracts are a foundation, with economic purchases as a residual beyond other sources
Local Capacity Area Requirements (repeated for each major local area)	(1:10 Peak Forecast – demand-side policy initiatives) – Local Import Constraint	Essentially all inputs except PRM that are needed for broad regions are also needed for each local area in order to determine local capacity requirements.	Jointly developed Scenario Screening tool for 2010/11 TPP process can be a foundational engine for calculations; inputs are generally from the same sources as for broad regions, but local area knowledge critical for some variables like CHP development.
		Impacts of possible transmission developments on local capacity requirements	California ISO 5-year ahead local capacity studies and any extension out to 10 years that results from joint agency proposal to SWRCB
Operating Resources			
Automatic Generation Control (AGC)	1-3%*(Peak Forecast – demand-side policy initiatives)	WECC is in the process of determining AGC requirements as part of conversion to frequency-responsive reserves proposal	Some information exists for California ISO, but little for POUs
Daily Ramping	No generally approved method for determining requirements[20]	At a minimum, the hourly ramping requirements associated with the evolving system (load and production sources) for various seasons of the year	The California ISO renewable integration study will produce preliminary estimates for one or more renewable scenarios. Little exists for the POU BAAs.
INCing (RegUp)	No generally approved method for determining requirements	At a minimum, the hourly ramping requirements associated with the evolving system (load and production sources) for various seasons	The California ISO renewable integration study will produce preliminary estimates for one or more renewable scenarios. Little exists for the POU BAAs.

20 To be determined by the California ISO 33 percent renewable integration study and other studies.

Element	Simplified Description of Infrastructure Addition Assessment	Necessary Inputs	Best Source[18]
		of the year	
DECing (RegDown)	No generally approved method for determining requirements	At a minimum, the hourly ramping requirements associated with the evolving system (load and production sources) for various seasons of the year	The California ISO renewable integration study will produce preliminary estimates for one or more renewable scenarios. Little exists for the POU BAAs.
Inertia	No method for determining requirements can be made public since procedures are confidential	Inertia constant of generating fleet, specific substations delimiting regions	Operating procedures like SCIT affecting imports or G-219/G-217 affecting subarea unit commitment need to be translated into the planning domain in order to determine whether these procedures create binding constraints for location and/or type of capacity additions
Contingent Resources			
Energy Reserves	No generally approved method for determining requirements related to multi-day production gaps from renewables due to weather conditions	The concept of an energy reserve to cover hydro shortfalls is recognized in the PNW, but has no broad acceptance in California.	A well designed production cost assessment exploring various renewable development patterns and testing in conjunction with uncertainties of variables.
Transmission[21]			
Reliability[22]	No simple description of the method for determining requirements	Load forecast, existing transmission system topology, assumed online generation are key inputs into power flow and stability studies by BAAs and transmission owners	California ISO annual TPP results due in March 2011 are using *2009 IEPR* demand forecast, but not other policy preference load modifiers.

21 Transmission need assessment and need conformance are difficult to distinguish since transmission benefits are less general and more specific to a given existing/projected electric system configuration.

22 Those projects that keep a system from falling out of compliance with NERC/WECC/Cal-ISO reliability standards in some future year.

Element	Simplified Description of Infrastructure Addition Assessment	Necessary Inputs	Best Source[18]
		PUC 1002.3 requires examination of demand side alternatives to transmission as part of the CPCN process for CPUC-jurisdictional projects.	Load modifiers developed as part of BAA need assessment would be logical source, but impacts have to be "smeared" to buses uniformly or differentially as insights suggest
Economic[23]	No simple description of the method for determining requirements, but logically it is an outgrowth of the project-specific assessments using the California ISO TEAM approach	Base case including reliability projects, plus numerous other assumptions about the cost of the project, the cost of the power to be imported, the cost of the power to be displaced, and so forth.	California ISO TPP results if any recent projects have been evaluated
Policy (Renewables)[24]	No simple description of the method for determining requirements, but the California ISO RETPP and CTPG processes have used power flow models with scenarios of renewable generation development in conceptual studies to identify hypothetical transmission system upgrades	Power flow base cases (numerous assumptions used to develop these), renewable scenario descriptions (amounts by location, technology, cost, environmental impacts, year of development, and so forth.)	CTPG Phase 3 and Phase 4 reports provide "conceptual" projects for one or more renewable development scenarios California ISO 2010/11 TPP results may move preliminary CTPG results into specific transmission projects for the California ISO BAA
		Increased clarity about acceptable renewable development areas via mechanisms like DRECP	California ISO and CTPG/RETI efforts in 2011

23 Those projects that reduce the overall cost of providing electricity to loads.

24 Those projects that assist in the attainment of public policy goals (renewable, OTC, and so forth), while keeping the system compliant with reliability standards.

Element	Simplified Description of Infrastructure Addition Assessment	Necessary Inputs	Best Source[18]
		Improved understanding of complete set of integration costs for each technology/location combination	California ISO renewable integration results for multiple CPUC/ED RPS scenarios will fine tune integration requirements to better understand technology and locational differences

Source: Energy Commission Staff

Schedule

Scheduling and coordination of analytical work with workshops may be the most important constraint in the production of this need assessment proposal. The final *2011 IEPR* Scoping Order proposes to limit workshops to the period of October 2010 through June 2011. Such a constraint would greatly limit both staff-generated analyses and ability to make use of analyses by the California ISO and others. For example, the OTC implementation schedule and analyses of criteria pollutant issues in the South Coast Air Quality management District (SCAQMD) through the Assembly Bill 1318 (Perez, Chapter 285, Statutes of 2009) process both call for major analytic studies to be completed in the fourth quarter of 2011. There are useful ways in which the substance of specific issues can be discussed in public workshops and hearings without dwelling on the implications for need assessment. In fact, such workshops might be useful for gathering information that can be used in the need assessment effort. Therefore, staff proposes that need assessment follow a series of workshops to surface preliminary analyses on specific topics, identify which components of analyses reveal differing perspectives, and perhaps provide an opportunity to talk with parties in follow-up discussions that would obtain inputs needed for the need assessment computations. Table 3 provides a high-level schedule for consideration.

Table 3: Proposed Schedule

Date	Activity/Event
October 2010	Draft CFM F&I released
October	CFM F&I workshops
October	IEPR Committee workshop on need assessment project scope and goals
November to March	Staff-level workshops on various topics
December	Final CFM F&I adopted by CEC
January – April 2011	IEPR workshops or hearings on electricity
February	Utility CFM filings submitted to CEC
May	Preliminary demand forecast published
May	Staff draft need assessment report released
June	Workshop on staff draft need assessment
July	Final date for analyses to fit into revised need assessment computations
August	Revised demand forecast published
August	Revised need assessment report released
September	Need assessment conclusions written for draft Committee *2011 IEPR*
October	IEPR Committee decisions leading to recommended demand forecast and need assessment results
October	Committee final need assessment report
November	Commission adopted demand forecast and final need assessment report published

Complementary Assessments

In addition to the fundamental variables describing need for infrastructure, the variables assembled to support need assessment calculations can also be used to calculate estimates of renewable net short, provided that demand-side adjustments to the baseline forecast are quantified in both energy and capacity terms. Staff has undertaken such calculations in the past and has committed to do so in this IEPR proceeding. Some of the same uncertainties influencing need calculations will also affect renewable net short. There may also be other variables of interest that can be supported by limited extensions of the basic variables required for need assessment.

Special Issues for Southern California

There are at least three topics that affect need assessment in Southern California that are not present at all or in much lower degree of influence for other regions of the state:

- Whether OTC power plants are likely to be retired and replaced at or near their site or with their capacity replaced elsewhere.
- The extent to which criteria pollutant offsets will constrain development of new greenfield plants (and perhaps all power plants, including replacement facilities at current sites).
- The extent to which transmission development can reduce local capacity area requirements and increase flexibility in the location of power plant development needed for the system as a whole.

These Southern California issues will be featured in a separate standalone analysis[25] prepared for the *2011 IEPR*, but they will also influence the need assessment project by expanding the range of possible outcomes when uncertainty is taken into account. At this point, staff proposes to apply the same methods described in this proposal to Southern California as a special region (partly within the California ISO and encompassing LADWP BAA), and to each of the local capacity areas affected by these issues. However, the range of uncertainty, and perhaps the numbers of alternative cases assessed, is likely to be larger than for other regions in California.

---

25 Assembly Bill 1318 requires the California Air Resources Board, in consultation with the Energy Commission, the CPUC, the California ISO and others, to conduct an electricity reliability assessment for the South Coast Air Basin. The Air Resources Board, the Energy Commission, the CPUC, and the California ISO are collaborating to conduct the necessary assessments aiming to provide a final report to the governor and legislature in early 2012. Some portions of this assessment will be available during the period of time that the *2011 IEPR* can accept inputs. These preliminary results, and the final Air Resources Board report in early 2012, will illuminate – but not eliminate – the uncertainties presently affecting electricity infrastructure assessment in Southern California.

Elements of Proposal Requiring Further Definition

There are five areas requiring further specification to complete staff's need assessment proposal:

1. Improved understanding of transmission as a complement to generation.
2. Improved understanding of instances in which generation and transmission options are substitutes.
3. The degree to which the capacity results of need assessments are assessed using metrics like total fuel used and its cost, GHG emissions in-state and out of state, and so forth.
4. The degree to which additional metrics for evaluating reliability can be addressed, for example, metrics beyond satisfying LCA requirements or BAA PRM standards.
5. Construction, impact assessment, and comparison among specific "cases" as opposed to a systematic examination of uncertainty.

Transmission as a Complement to Generation

For several IEPR cycles the Committee has accepted staff's proposed *Strategic Transmission Investment Plan (STIP)*. These *STIPs* have included projects identified and assessed in other forums. During the *2009 IEPR*, transmission planning organizations proposed to create the CTPG, a new statewide forum for transmission planning evaluations. CTPG's efforts in late 2009 and to date in 2010 have produced a large amount of transmission analysis for renewable development that has been prepared by the CTPG and that is intended to be refined over the next six months by the individual transmission owners. Unfortunately, the aspirations of the CTPG effort – investigation of alternative renewable buildout patterns leading to a small number of common transmission elements – have apparently not been realized. CTPG has identified numerous high and moderate priority transmission upgrades, but most are dependent upon uncertain input assumptions. Therefore, rather than transmission needs being simple and substantially independent of the details of renewable generation development, they have been shown (at least through CTPG analyses to date) to be highly related to specific renewable buildout assumptions. Since it is well understood that renewable buildout remains highly uncertain, the linkage between generation assessments and transmission assessments means that transmission needs are highly uncertain.

Transmission as Substitute for Generation

The most substantive area requiring further development is understanding the tradeoff between generation and transmission where these are substitute, not complements. The linkage between generation development and transmission development is now uppermost in many minds due to the publicity about alternative patterns of renewable development, and the "radial" nature of transmission needed to access such generation sources and move the power to load centers. The CTPG Phase 3 report and the efforts by each major transmission entity (California ISO, IOUs, and major POUs) to evaluate their individual transmission needs will play out over the next year or more. Unfortunately, the more mundane issues of transmission substituting for generation within load centers, thus reducing local capacity area requirements have not received corresponding effort. The CTPG planned to address the consequences of phasing out OTC but determined that it could not accomplish this and renewable development assessments, so it dropped OTC assessments from its 2010 effort.

While it is indisputable that the California ISO and LADWP are aware of the OTC phase-out, only the California ISO has firm plans to conduct assessments. The California ISO may release a preliminary assessment in the first quarter of, but it is assuming that the generator compliance plans to be submitted to the State Water Resources Control Board (SWRCB) in about March 2011 will require a revision of those assessments so that a more complete view of transmission versus OTC capacity replacement will not be complete until the third or fourth quarter of 2011. LADWP released a draft integrated resource plan (IRP) during the summer of 2010, but the IRP is virtually silent about any of these issues. At this writing, it is unclear how analyses to support generation versus transmission tradeoffs can be orchestrated in the timeline necessary for the *2011 IEPR*.

Evaluation of Capacity Results Using Metrics Like Fuel Cost and Greenhouse Gas Emissions

Capacity-based need assessments provide a firm focus on the amount of infrastructure required and capacity additions can be described in terms of capital and investment costs, but this is insufficient to allow comparison between cases since the "production cost" aspects of operating the system are missing. Production cost models allow estimation of fuel consumption, GHG and other environmental emissions, displacement of out of state power, and so forth. Staff is shifting its production cost platform from Ventyx's Enterprise suite to Plexos, which will allow the staff to run the same datasets being used for part of the renewable integration effort led by the California ISO with support from Nexant and Southern California Edison (SCE). To the extent that specific "cases" are developed and assessed, these metrics might be produced; however, it is unclear how one would prepare such assessments for "ranges" of need since these may not correspond to any single case. At least for this IEPR cycle, evaluation of desired metrics may have to be limited to a subset of the full range of need.

Reliability

A capacity-oriented need assessment can assure that capacity-oriented measures like the planning reserve margin (PRM) and local capacity area requirements are observed. However, satisfying these planning criteria does not assure that reliability is satisfied in a manner that matches general industry standards, as measured by loss of load expectation (LOLE). Further, there is emerging evidence that constraints California ISO operating procedures like G-219 (South of Lugo), G-217 (Orange County) and Southern California Import Transmission Nomogram (entire Southern California region) may place constraints on system development that are not publicly appreciated. Staff does not have much independent capability in these areas, other than expertise that can be hired through contractors. Limited budgets may imply that these are topics that are raised rather than whole and complete analyses that can be contributed into the need assessment. Some agencies consider these topics to be confidential, which will likely inhibit willingness to provide data and to discuss the issues in public settings.[26]

Evaluation of "Cases"

One approach to evaluating uncertainty is to construct, develop impacts, and then compare across several "cases." A "case" might reflect the planning assumptions organized by another agency, for example, an AB 32 case as defined by the Air Resources Board's (ARB) AB 32 *Climate Change Scoping Plan*. The CPUC's set of planning assumptions that define IOU service area need might be considered a "case." Assessment of a series of such cases would result in a range of need for each of the principal elements as defined earlier in this section. As discussed more fully in Section V on uncertainty, this is a tried and true method for showing uncertainty. However, this approach is likely to understate the true range of need given the uncertainties that exist in each of the principal input variables. Currently, staff is inclined to assess both a true range and several obvious "cases" like the CPUC's LTPP *Scoping Plan* and the ARB's *Climate Change Scoping Plan*.

Section IV: Coordination with CPUC and California ISO Proceedings

Need Assessment Inputs Drawn from Other Proceedings

Table 3 identified that the Energy Commission staff is not the "expert" for many of the inputs. Staff is proposing to pursue the collaboration directive called for in the *2009 IEPR* by drawing upon the expertise of other agencies. The CPUC LTPP rulemaking and the various California ISO studies are expected to be the main sources of this information. To some extent, this can be accomplished with staff simply using information made available by other agencies in their proceedings. For example, staff understands that the CPUC's 2010 LTPP Scoping Memo and its attachments will provide most, if not all, of the information needed to construct a "case." Acquiring better versions of this information, perhaps ones customized to fit this proposed need assessment, will require coordination with, and

---

26 In the *2009 IEPR*, the California ISO formally complained about staff presenting summary information about the Orange County Operating Procedure – G-217. The California ISO was concerned that even this aggregated treatment of the subject exposed confidential information. Staff believes that it is essential that operating procedures and other means by which the California ISO differentiates between and among power plants be surfaced in a planning forum in some way. If it is important to system stability that a certain amount of capacity be located in Orange County to enable the system to withstand instabilities caused by transmission or generation outages, then that must be understood in sufficient detail that the planning process can steer development of generation and transmission in ways that respect these concerns.

therefore some dependence on, additional activities of these and other agencies like the ARB, the SWRCB, the South Coast Air Quality Management District, and others.

CPUC 2010 LTPP Rulemaking

The CPUC intends to issue instructions for “system” assessments via an Assigned Commissioner Ruling/Scoping Memo that directs the IOUs to conduct portfolio assessments using a highly specified set of assumptions. The product would be due in March-April 2011. Adjudication of the filings through hearings is expected in May – July. A decision is expected in November-December 2011. Staff believes that some input assumptions that the CPUC intends to require IOUs to use are as good or better than any comparable analysis the staff could develop in this timeframe, and thus plan to make use of them. If necessary, staff will request information from CPUC to allow the Energy Commission’s analyses to benefit from CPUC efforts.

California ISO Proceedings and Special Analyses

The California ISO is a source of key information for several topics, including:

- Renewable integration requirements.
- Transmission required to allow renewable development.
- Local capacity area requirements.
- Overall Southern California system stability constraints on resources, such as SCIT.

These same topics are being undertaken by the California ISO, sometimes in conjunction with the energy agencies for other purposes, so staff is hopeful that California ISO analyses will be forthcoming in the time frame useful for the *2011 IEPR*. Staff proposes to work with the IEPR Committee to devise effective strategies or approaches most likely to draw the California ISO into being an active participant in the infrastructure assessment process.

State Environmental Agencies

ARB and SWRCB are each responsible for “forcing” progress on important constraints on the generating system in California. ARB is responsible for moving the ball forward on offsets for power plants in the South Coast Air Basin through AB 1318. The existing inter-agency OTC team has adapted itself to work on the analytic issues associated with reliability in the basin, but the schedule ARB is pursuing for its AB 1318 report (early 2012) does not mesh well with *2011 IEPR* schedule. In contrast, SWRCB’s OTC policy has been adopted and approved by the Office of Administrative Law. Analytic activities associated with generator compliance plans, near-term reliability, and so forth, can generate some information that is helpful in the *2011 IEPR* schedule.

Inputs from IOUs and POUs

Inputs from the IOUs and POUs will be an important source of information for the infrastructure assessment. At this time, staff does not propose that new information to support need assessment be required of utilities; rather, staff proposes that the Common

Forecasting Methodology (CFM) filings document the mandated package of assumptions required in the CPUC's LTPP rulemaking and any "utility-preferred" cases developed by an IOU, and that staff acquires additional information and performs the need assessment computations itself.

Investor-Owned Utilities

IOUs have to pay attention to both the CPUC's LTPP rulemaking and the *2011 IEPR*, and, unfortunately, the 2010 LTPP proceeding is on much the same schedule as is the *2011 IEPR*. Although the sum of the three IOUs system analyses is not the same as the California ISO BAA (the CPUC use of the term "system" omits small, embedded POUs within the California ISO), the portfolio analyses of the IOUs will be useful. IOUs will be directed to undertake a highly complex set of portfolio assessments, to be guided by an Assigned Commissioner Ruling issued by CPUC President Michael Peevey, with a product due to the CPUC in roughly March – April 2011. Staff proposes to require IOUs to submit CFM filings in March 2011 that allow IOUs greater flexibility to devise their own assumptions for the future and to identify the types of resources that make the most sense to add over time to satisfy need. Any required assessments and alternative views will create more information about future uncertainty that can be used to extend staff's knowledge base about uncertainties for key variables.

Publicly Owned Utilities

Energy Commission requests to POUs will be the source of information used to conduct this analysis as well as resource adequacy assessments, which is a specific element of IEPR evaluations pursuant to Assembly Bill 380 (Núñez, Chapter 367, Statutes of 2005). [27]

- Existing CFM regulations create a size cutoff of 200 MW peak demand for more data-intensive requests to larger POUs. This matches up with POUs operating more independently from the California ISO as their own balancing authorities.
- For the larger POUs, Energy Commission staff proposes that the CFM data request parallel the analyses that IOUs and the CPUC and its Energy Division staff will have conducted for IOUs.
- For smaller POUs, staff will extrapolate the POU responses submitted pursuant to one-year ahead resource adequacy data requests to create the 10- to 12-year time horizon for loads and resources.

Transmission Owners

In the *2009 IEPR*, the Energy Commission concluded that transmission planning should be much more highly coordinated with generation planning than has been the case in California. The CTPG effort to examine how satisfying a large renewable development goal creates transmission needs and the California ISO tariff proposal to FERC to integrate

[27] Public Utilities Code section 224.3 defines a local publicly owned electric utility.

renewable transmission development into its transmission planning process are evidence that the industry supports the *2009 IEPR* conclusion.

- What amount of quantitative analysis of transmission system additions is appropriate for both IOUs and POUs to submit into the 2011 IEPR proceeding?
- Are such requests generally to be satisfied by copies of CTPG assessments and any follow-ups by individual BAAs?
- Are such requests highly specific, such as for in-depth examinations of OTC power plant retirement and replacement by remote capacity with upgraded transmission lines?

Section V: Addressing Uncertainty

Staff proposes to explore and document the sources of uncertainty in each of the inputs to the calculation of need, and to carry such uncertainties through the need assessment computations to show a range of electricity infrastructure requirements. No credible need assessment for resource additions can avoid examining the associated uncertainties. A few examples identify the uncertainties that staff is considering:

- How might the uncertainties in the recovery of California's economy from the current recession shape the range of electricity demand?
- To what extent will the pattern of renewable development affect transmission upgrades required and dispatchable resource required to integrate it to serve load reliably?
- How will customer response to installation of smart meters, dynamic pricing, and other rate changes cause traditional patterns of electricity demand to change?
- What success in achieving the energy efficiency policy initiatives that the Energy Commission considers "uncommitted" should be assumed to occur?
- How will OTC power plant operators respond to the SWRCB's OTC mitigation requirements?

Simply assuming "most likely" values for these uncertainties runs the risk of either developing infrastructure that is not needed or failing to develop infrastructure in a timely fashion.

Broadly speaking, the following questions must be addressed:

- What are the principal sources of uncertainty that affect each of the inputs and relationships for infrastructure need?
- Given some level of uncertainty in each input, what range of values is plausible, given our current state of knowledge, within the time horizon of interest?
- How does the uncertainty change for each input as the time horizon changes?

Addressing these uncertainty questions for key inputs will provide opportunities to calculate alternative versions of overall BAA and LCA need, thus translating input uncertainty into need uncertainty. Hundreds of possible combinations of the key assumptions could easily be calculated. We understand that a tradeoff exists between acknowledging and tracing them through the separate and joint uncertainties to identify a range of need, and the desires of decision makers and clients of a need assessment to be able to make decisions about infrastructure needed to "keep the lights on." Staff expects this aspect of its proposal to undergo further development and refinement, through internal discussion, and in comments from stakeholders following the release of this white paper.

It is now standard practice to acknowledge uncertainties when reporting the results of a planning assessment, but it is much harder to determine the appropriate method for actually quantifying the consequences of such uncertainties. A few approaches are listed below:

- Quantifying multiple "cases" composed of a specific package of assumptions about the future, for example, an electricity system compatible with the ARB's *Climate Change Scoping Plan* through 2020.
- Alternative cases assessing sensitivities for a few key variables around a "central tendency" baseline.
- Probabilistic methods translating statistical and subjective probabilities for inputs into a probability distribution for a range of infrastructure additions for each key infrastructure element.
- Uncertainty techniques that use simplified methods of projecting outcomes in association with massive numbers of alternative cases covering the entire combination of input variation possibilities to reveal the combinations that are most adverse (perhaps then requiring more in-depth study by conventional techniques).

There are tradeoffs between the degree to which uncertainty in input assumptions is formally recognized as output uncertainty and the ability of decision makers to absorb and use the results. To some extent, repeating planning processes on a regular cycle (such as the IEPR's biennial cycle or the CPUC's LTPP cycle) allows a less rigorous examination of uncertainty compared to a single "once and for all" decision that has to choose among a limited set of options. Given that infrastructure need assessments are likely to be performed every two years, some share of investment in infrastructure can often be delayed with the expectation that uncertainty will be reduced by the next planning cycle. Decisions on infrastructure can be limited to "no-regrets" investment that will be necessary over the widest range of potential outcomes. Admittedly, the opportunities to delay today's electric infrastructure decisions are limited by the long time lags in permitting and construction. Although the industrial engineering community has broadly implemented "just in time" delivery of parts for industrial assembly operations so as to minimize onsite inventories, the flexibility of centralized decision making and control that these firms exercise over parts suppliers does not readily translate to the regulated electricity industry.

Section VI: Possible Purposes for Specific Types of Infrastructure Need Assessment

Many possible purposes for specific types of infrastructure addition assessment exist among the energy agencies and larger utilities today. There is a possible role for an overarching infrastructure addition assessment that would both receive contributions from and be used by multiple agencies in recognition that any one agency has neither the resources nor the expertise to cover all facets of electric system infrastructure. This section addresses some of the ways that infrastructure addition assessment might be developed to support the broad role of quantitatively describing the amounts and types of infrastructure "needed" to achieve California's Clean Energy Future vision for the electricity system.

Purposes that a more rigorous infrastructure need assessment process could assist include: [28]

- Supporting the CPUC in establishing IOU procurement authority out seven years for bundled customer energy and capacity requirements.
- Systemwide resource adequacy as the forward time horizon is pushed out five to six years. [29]
- The joint Energy Commission-CPUC-California ISO proposal to the SWRCB to establish and periodically revisit a plan that would allow existing OTC capacity to be repowered onsite or retired and replaced elsewhere using generating technologies with less environmental emissions. [30]
- Better understanding the consequences of multiple policy initiatives on need for infrastructure by type, location and year.

---

28 The CPUC/ED straw proposal of July 2009 for the 2010 LTPP proceeding suggested a much more comprehensive process design than had existed in advance for preceding cycles of the LTPP process. It identified the potential sources of much of the information needed, and it proposed to expand the scope of the LTPP to address system issues and policy issues not well recognized as a LTPP function in earlier cycles. Among these were the linkages between OTC retirements and transmission system upgrades, renewable development and transmission upgrades, and the quantitative consequence of the EAP resource preferences on multiple categories of need. The LTPP rulemaking issued on May 6, 2010 (R.10-05-006) did not expressly endorse the straw proposal, although it incorporated by reference the record of the 2008 LTPP rulemaking.

29 Various forms of a multi-year forward capacity market were debated in R.05-12-013 for several years. D.10-06-018 concluded that proceeding by retaining current LSE obligations, but endorsing a collaborative planning process by CPUC, the Energy Commission, and the California ISO to determine future resource needs.

30

http://www.waterboards.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/sed_final_c.pdf

- Better understanding if the uncertainty surrounding need for infrastructure by type location and year, including:
  - Capacity needed to satisfy planning reserve margins.
  - Capacity requirements for local areas as a result of mismatches between transmission configuration, generator locations, and end-user load patterns.
  - Flexible capacity needed for intermittent resource integration transmission requirements to support 33 percent renewable development.
- Better understanding of the extent to which storage technologies of various capabilities can satisfy some of the need for flexible generating technologies
- The electric reliability study for South Coast Air Basin required by AB 1318 requires a one-time study to determine reliability requirements for this region, but the proposals from the ARB in consultation with the energy agencies may result in an ongoing process to periodically update capacity infrastructure additions as a dedicated offset bank is refreshed.

In addition, the *2009 IEPR* described as one use for infrastructure addition assessment as the eventual creation of need conformance in the permitting of power plants, both those subject to the CEC's licensing jurisdiction and others permitted by local agencies. The *2009 IEPR* directed that a stakeholder process should be pursued to address that specific purpose.

Staff believes that bullets 2, 3, 4 and 5 of the above list are the best purposes for which this proposal can deliver results in the time frame of the *2011 IEPR*. Bullet 1 cannot be directly satisfied by this proposed effort since the analyses are not oriented to identify IOU bundled service needs, but rather physical needs at the BAA and LCA level. Bullets 6 and 7 need their own specific processes, which are now underway as a result of recent of legislation. Finally, any potential need internal to the Energy Commission to assess power plant applicants using a need perspective can use the information generated by this project and which would also satisfy bullets 2, 3, 4, and 5.

Section VII: Conclusion and Next Steps

This white paper is intended to provide necessary background to allow an in-depth discussion with stakeholders regarding the design of an infrastructure need assessment project for the 2011 IEPR proceeding. As the *2009 IEPR* calls out, infrastructure need assessment is already being conducted by several agencies in specific ways suited to the questions they believe they need to answer. Some degree of collaboration is already happening as one agency makes use of the specialized expertise of another, for example, the CPUC relying upon the long-term demand forecasts of the Energy Commission for its LTPP rulemakings, which authorize infrastructure procurement by each IOU. To some extent, infrastructure addition assessment results can be constructed for elements by drawing upon the results of infrastructure addition assessment processes of these other agencies. Such linkages can be made tighter than they are today and could be made even tighter if the sort of interagency coordination discussions addressed in the CCEF documents are successful.

The broad scope of this project necessarily encounters topics for which only limited progress can be made in this cycle or that are not as useful to resolving current policy questions as others. Below are a sample of questions and constraints that stakeholders might address in comments.

- Although one might imagine that infrastructure addition assessment ought to address the totality of elements called for in the California Clean Energy Future vision document, some of the elements included in that document are so "visionary" that it is not possible to conduct formal assessments that parallel what is currently understood as generation or transmission infrastructure addition assessment. For example, storage technologies offer considerable promise as substitutes for dispatchable fossil generation in satisfying some components of renewable integration. However, storage technologies do not appear capable of providing the system stability benefits that traditional generating technologies provide. The concept of a smart grid facilitating the use of storage in some adaptive manner, perhaps analogous to the role that automatic generation control plays today, is just that, a concept. Much greater understanding of the capabilities of smart grid technologies and how they complement or substitute for existing methods of system operation will be needed before these could possibly be considered in a formal "infrastructure addition assessment" manner.
- **Table 3** distinguished between system capacity and local capacity requirements. In the usual way these terms are used within the resource adequacy community, system would refer to the California ISO-controlled grid, while local capacity requirements refers to the 10 load pockets that are now regularly assessed in the annual California ISO/CPUC process. Each of the four other balancing authorities would interpret "system" to be their own BAA, since that is what is relevant for their planning purposes. The Energy Commission commonly refers to "statewide," but generally that means the sum of the five BAAS located wholly within California and excludes the portions of Pacificorp BAA in the far north and Sierra Nevada in the Lake Tahoe region.
- Covering all the BAAs seems logical to allow statewide conclusions, but raises some questions. Is an in-depth examination of all 10 load pockets in the California ISO warranted? Is there some subset of load pockets that presents especially critical planning and reliability issues? Is it acceptable that for other load pockets an analysis be conducted by some other entity or examined in less depth? Should the LADWP system be examined in more depth, especially since LADWP asserts in its filings to the State Water Resources Control Board regarding OTC compliance scheduling that the radial design of its system causes local voltage and stability issues and requires all of the capacity from its existing power plants to be maintained or equivalent capacity from repowered units?

- Some renewable integration studies, especially those for wind and solar, examine generation variations in time units of minutes or shorter to determine the consequences of variable production on local voltage or transmission element sizing rather than the more common hour time interval for local capacity requirements, production cost modeling, and many other purposes. Is it necessary to examine these very short time intervals on a regular basis, or could supplemental studies on this time interval augment basic infrastructure addition assessment conducted on an hourly basis?
- Transmission need conformance/infrastructure addition assessment distinguishes between small scale reliability projects below $50 million that the California ISO Board acting alone can authorize and for which IOUs can obtain rate recovery from larger projects that have to undergo the more formal Certificate of Public Convenience and necessity process. Can this sort of transmission project categorical distinction be adapted for the Energy Commission's infrastructure need assessment so that the small projects are not addressed?

Stakeholders can provide a useful check on this proposal by providing comments at the planned workshop or in a follow-up comment opportunity. Staff will review all comments, and staff and the IEPR Committee will determine to what extent modifications to this proposal should be made.

APPENDIX A: Inputs and Sources for Calculating Infrastructure Needs

Questions – Demand

System Infrastructure Needs

How much total capacity (MW), and with what set of operating characteristics, needs to be added in each year for each balancing authority area (BAA) to satisfy planning reserve margin standards and renewable integration needs, taking into account load growth, retirements, and committed capacity additions?

[[1:2 Peak demand forecast – demand side modifiers] X [1 + Planning Reserve Margin]] + [renewable integration needs] [not a bullet]

Less [existing and near-term committed resources] + [assumed renewable and CHP additions] - [expected retirements] [not a bullet]

Local Infrastructure Needs

How much total capacity, and with what set of operating characteristics, needs to be added in each year in each local capacity area (LCA) to satisfy local capacity requirements (LCR) and meet other local reliability needs, taking into account load growth, retirements, and committed capacity additions? This requires satisfying the following equation:

LCA resources > [1:10 peak demand forecast for the LCA –demand side modifiers] – [Local Import Constraint] [not a bullet]

Peak Demand Forecast and Impacts of Demand-Side Modifiers – System Need

What is the 1:2 peak demand in each year for each BAA? What is the impact of demand-side policies (Uncommitted energy efficiency, demand response programs, and distributed generation]? [Note: items below should not be bullets, need some other formatting used in this little subsection and the numerous subsections that follow]

Necessary Inputs

1:2 peak demand forecast, including adjustments for incremental (uncommitted) EE, incremental self gen/CHP (on-site use as demand modifier), and demand response program impacts.

Sources

2011 IEPR Demand Forecast; incremental (uncommitted) EE from Incremental-Uncommitted EE Report; incremental selfgen/CHP from existing ICF study or other studies; demand response from historical program performance data , IOU/CPUC and POU projections of future programs/performance. Incremental EE, CHP, and DR assumptions will also be made in the CPUC's LTPP proceeding. The proceeding will also yield assessments of potential and plausible values for these components that will be considered.

Comments

- The timing of the *2011 IEPR* Demand Forecast may render its use in a preliminary infrastructure assessment impractical. Assuming that the 2009 and 2011 forecast will not be substantially different in outer years (2017, 2022), this does not present a major problem. The revised infrastructure assessment could make use of the preliminary 2011 demand forecast.[Note: the two "bullets" below are part of Comments, so in this subsection there are three parallel comments.]
- Assumptions regarding uncommitted EE and CHP are expected to be highly contentious issues in the CPUC LTPP proceeding. Target levels for CHP (in MW) as established by AB 32 Scoping Plan may be unrealistic, at least for use as planning assumptions; CHP would have to be treated as sensitivity for modeling purposes(CHP is discussed in more detail below as a supply-side resource, only on-site use is considered a demand-side modifier).
- Distributed renewable generation (here meant to include distributed solar PV other than small rooftop; small rooftop solar under the CSI is incorporated directly into the demand forecast) may include up to 20 MW facilities whose output may not be consumed locally, it is thus considered a supply-side resource (despite the possibility of some on-site use) and is discussed in the Supply section.

What policy-induced changes in end use technology increase peak demand? (For example, EV's, port electrification)

Necessary Inputs

Quantitative consideration of the (likely or potential) impact of increases in electricity usage resulting from policies that ARB and/or other agencies are pursuing to reduce GHG emissions from end-user combustion processes

Source

Program impacts considered committed ought to be included in the ESAD/DAO analysis as part of demand forecast, but programmatic "electrification" resulting from GHG end-user emission reduction programs may not have a "home" in the current accounting processes leading to need computations.

Comments

- It is possible but not certain that a detailed assessment of, for example, EV penetration will need to be part of the demand forecast. Should parties believe that the 2011 forecast would contain markedly different assumptions regarding EV than the 2009 forecast, the infrastructure assessment might have to be updated to account for this change at such time that the 2011 draft or final demand forecast is available.

1:10 Peak Demand Forecasts for LCAs and Demand-Side Modifiers – Local Needs

What will be the 1:10 peak demand for each relevant LCA? How will demand-side modifiers affect these?

Necessary Inputs

1:10 peak demand forecast for each LCA, including adjustments as in 1:2 system peak demand forecast. *LCA-specific* adjustments for CHP, possibly for uncommitted EE, distributed generation, incremental CSI and demand response as well.

Sources

2011 IEPR (1:10) forecast (or continued use of 2009 forecast), then allocated to LCAs by ESAD staff, with LCA specific adjustments for CHP from the ICF report and/or other sources, including those that may be proposed in the CPUC LTPP proceeding. Other load-modifiers tend to be based on load shares (see Comments). This allocation has been done using the 2009 demand forecast.

Comments

- The ICF report provides a basis for LCA-specific allocations of incremental CHP, but parts of it (for example, the cost curves) will need to be reviewed given its dated nature. Staff will revisit, if not revise CHP assumptions based on an assessment of the likely impact of the recent settlement agreement, discussions with developers, and information generated in the LTPP proceeding.
- Allocations of EE, demand response, and so forth, are frequently made on a load-share basis (for example, if demand response programs reduce SCE peak loads by 1,000 MW and the Los Angeles Basin LCA has 62 percent of SCE’s load, the LCA peak is reduced by 620 MW).

Planning Reserve Margin for System and Renewable Integration Needs

What planning reserve margin will the system need to be built to? Will this be more than 15 percent-17 percent if only due to intermittent renewable integration needs?

Necessary Inputs

Agreed-upon planning reserve margin, currently 15 percent – 17 percent, estimates of incremental capacity needed to reliably integrate intermittent renewable resources

Sources

CPUC Planning Reserve Margin proceeding (R.08-04-012), California ISO 33 percent renewable integration studies.

Comments

- An August 23, 2010, proposed decision calls for closing the CPUC proceeding without recommending changes to the current planning reserve margin.
- The 20 percent and 33 percent renewable integration studies being undertaken by the California ISO suggest that a reserve margin in excess of 15 percent – 17 percent will be necessary to reliably integrate intermittent renewable resources. The need for additional reserves will depend upon numerous factors, including load growth, renewable development, improvements in forecasting, and changes in the incentives provided ancillary services and the manner in which they are procured. Staff will utilize the California ISO studies and work with the California ISO to develop estimates of potential ranges of the additional capacity needed beyond a 15 percent – 17 percent reserve margin to integrate intermittent renewable.

Local Capacity Area Requirements

What transmission upgrades presently under consideration can be assumed to be built? What impact will they have on transfer capability into the state and into LCAs?

Necessary Inputs

The set of transmission system upgrades likely to be completed through 2014 – 2015 and their impact on transfer capability.

Source

Information in recent California ISO and other BAA transmission planning documents and studies; updates from the California ISO; filings by other BAAs in the IEPR proceeding.

Comments

- While information regarding planned upgrades is readily available, more information regarding the likelihood that these upgrades will occur and their impact on capacity needs in LCAs is needed. This information will be solicited from the California ISO.

What will the local capacity requirement (LCR) be for each LCA over 2015-2020? What transmission upgrades will occur over 2015 – 2020 and what impact will they have on LCAs?

Necessary Inputs

Long-term LCR studies, which require assumptions about (a) 1:10 peak demand with adjustments for demand-side modifiers, (b) added and retired generation in the LCA, and (c) transmissions upgrades that increase the amount of energy that can be imported.

Source

California ISO, LADWP

Comments

- These studies are especially significant as they indicate, when OTC plants are retired, how much replacement (dispatchable fossil) capacity is needed in the LCA.
- Forward-looking LCR studies are a subject of discussion within the inter-agency working groups on once-through-cooling and the potential need for new capacity in the Los Angeles basin. Such studies tend to require numerous scenarios, as, while the LCR indicates what capacity is needed in an LCA, the local capacity that is assumed to exist in the study influences the amount that is needed, so retirements and new construction must be modeled. In addition the LCR is very dependent on the transmission system, so forward-looking estimates must consider upgrades to it. At some point out in the future, transmission upgrades become conjecture; the possible set of additions during 2015-2020 is not bounded; the plausible set of additions is not known to Commission staff and must be sought from other sources (the California ISO, CTPG) who themselves may have not considered the full range of alternatives. The California ISO justifies transmission projects on "other than LCR" grounds; once approved the upgrades are assumed in LCR studies. LCR studies are, as a rule not performed under varying assumptions about (potential) transmission upgrades as this potentially involves numerous scenarios. As a result, long-run LCR studies are not routinely done by the California ISO.
- Staff will work with the California ISO to develop plausible ranges of LCR needs through 2022. It will also work with the other BAAs to evaluate the potential changes in local capacity needs through 2022 as a result of changes in demand and upgrades to the transmission system.

Questions – Supply

Existing and Near-Term Committed Resources

What new fossil plants and renewable plants can be assumed to be built (i.e., are committed)?

Necessary Inputs

List of projected new plants. Staff maintains database of existing facilities.

Source

Existing information from Siting Office queue, POU commitments, IOU contracts, IEPR filings, CPUC assumptions about near-term renewable construction.

Comments

- In some instances this may include generic fossil plants that are expected to replace OTC facilities; for example, the capacity that is expected to allow the retirement of Encina.

Expected Retirements

What fossil plants can be expected to be retired?

Necessary Inputs

List of plants that might retire due to age, must retire due to SWRCB OTC policy, or may discontinue operation as a result of the recently negotiated QF settlement.

Source

Staff can reasonably assume that most aging POU resources, if retired, will be replaced on site due to local capacity requirements. Assumptions will have to be made regarding a handful of aging merchant facilities (for example, Long Beach, Etiwanda, and Coolwater). Estimates of potential OTC retirements and their timing will be developed based on OTC compliance filings with the SWRCB, and discussions with generators. These estimates will also informed by discussions of the interagency working groups and the record developed in the LTPP proceeding.

Comments

- Estimates of potential QF retirements will be developed based on IOU supply filings in the *IEPR*, discussions with QF owners, and the record developed in the LTPP proceeding.

Long-Term Supply: Renewables

What will the State's renewable portfolio look like through 2020? What share of new renewables procured by California utilities will be out of state? What share will be in Northern and Southern California? What CREZs will be developed? What should be assumed about REC policy?

Necessary Inputs

Renewable buildouts (scenarios) that represent plausible development though 2022.

Sources

Renewable scenarios developed by the CPUC for consideration in the LTPP proceeding and use by the California ISO in their renewable integration studies, additional scenarios developed by the California ISO for use in its studies, other buildouts developed by Energy Commission staff if necessary.

Comments

- The amount of renewable energy needed to meet targets expressed as a percentage of load depend upon load growth and above-mentioned load modifiers. Integration of demand-reducing policies and renewable development could potentially affect both the amount of renewable as well as the type/location of renewable if demand-reducing measures diminish the need for renewable enough to make developing resources and associated transmission in some CREZs uneconomic.

- The renewable buildouts are a key driver of several other inputs and output , including the residual need for gas-fired capacity (to meet reserve margin requirements and integrate intermittent resources) the necessary operating profile and characteristics of this capacity, and so forth.
- Key dimensions of renewable build-outs include the composition of technologies (i.e., shares of solar and wind), which influence the capacity realized from renewable development. This composition also affects the (hourly) time profile of renewable generation and thus the need for additional (dispatchable) capacity to integrate them. They also include the extent to which tradeable renewable energy credits and firmed and shaped out-of-state resources are used to meet targets, as these reduce the need for California BAAs to integrate intermittent resources into their systems. The extent to which distributed generation is deployed to meet renewable targets is of significance as reliance on remote central station resources may preclude the timely meeting of renewable energy targets due to the need for bulk transmission upgrades.
- Any year-over-year buildout (as well as buildouts for 2020 alone) should be consistent with feasible development(s) of bulk transmission.

What should be assumed about the development of distributed renewable generation (2 – 20 MW solar PV; larger than CSI/small rooftop)?

Necessary Inputs

A buildout or buildouts of distributed PV, disaggregated down to the LCA level.

Sources

E[3] and Black and Veatch have developed crude estimates of the technical potential for distributed PV (by both technology and region) as consultants to the CPUC LTPP proceeding, Staff, either directly or through participation in the LTPP proceeding will secure the assistance of parties in developing reasonable ranges for assumptions regarding the future development of larger distributed renewable PV resources.

What is the peak capacity value of intermittent renewables?

Necessary Inputs

Estimate of peak capacity value of intermittent renewables

Sources

For wind capacity, historical values for existing resources given protocols for establishing "net qualifying capacity." For solar technologies, estimates developed for use or consideration in the LTPP proceeding, information from the California ISO's 33 percent renewable integration studies (forthcoming), can be used although values have likely not been developed for different technologies or regions.

Comments

- Values are necessary to estimate residual need for capacity from non-renewable resources, both in aggregate and by LCA. To the extent there are valid disagreements about renewable capacity value, they need to be assessed and resolved.

Long-Term Supply: CHP

Necessary Inputs

Assumptions regarding the amount of CHP (MW), its allocation across LCAs, and the allocation of that generation to on-site use and export.

Sources

ICF study, assessment of likely impacts of QF settlements, assumptions made in the CPUC LTPP proceeding

Comments

- Despite its being a preferred resource in the ARB's *Climate Change Scoping Plan*, the retention of existing CHP and development of new CHP resources through 2022 is very uncertain.

Long-Term Supply: Fossil

The factors discussed above – peak demand and demand- side modifiers, planning reserve margins, retirements, local capacity requirements, renewable and CHP development – drive the need for capacity from new fossil resources.[31] Exactly what operating characteristics this fossil capacity should/are required to have remains to be investigated.

What are the required operating characteristics of new fossil plants? In general? In specific LCAs?

Necessary Inputs

Estimates of ramping and ancillary services needs associated with the integration of intermittent renewables.

Sources

California ISO 33 percent renewable integration study.

31 Reference to dispatchable fossil resources does not negate the possible role that storage technologies might play in satisfying some portion of the needs currently carried by dispatchable fossil generation. However, there is no standardized manner of describing the specific capabilities of "storage" or its degree of control by system operators. Absent this, ESAD assumes that storage remains a niche or R&D technology with promise, but not yet able to play a substantive role in displacing dispatchable fossil generation.

Comments

- New and replacement gas-fired capacity is needed to meet system-wide planning reserve margins and local capacity requirements, integrate intermittent renewables, and to provide inertia and meet "very local" reliability needs within the Los Angeles Basin (see below). Each of these may indicate a need for different operating characteristics, and thus different types of dispatchable, gas-fired generation.

Questions – Transmission-Related and Capacity Constraints

There are other transmission-related constraints that may require study as they have an impact on the amount and location of gas-fired generation that will be needed given a specific renewable buildout or set of assumptions regarding transmission upgrades.

What constraints are placed on the development of both renewable and fossil development by the Southern California Import Transmission (SCIT) nomogram, i.e., the need to supply enough inertia in Southern California to ensure grid stability and maintain imports?

Necessary Inputs

A study of the potential residual need for inertia (if any) for selected renewable build-outs. This would isolate residual needs for inertia from gas-fired generation and thus the minimally needed MW of new gas (net of retirements) in Southern California and how it might have to be dispatched. This study would require inertia values for existing and planned (both identified and "generic") new generation and enough information regarding the location of new development to determine whether SCIT requirements were satisfied going forward.

Source

The This study would require substantial assistance from the California ISO, including the provision of inertia values and load and import data, as well as assumptions about the evolution of the SCIT nomogram as the transmission system is upgraded during the next 10 years.

Comments

- This study is necessary as, as participants in the 2009 IEPR proceeding pointed out, the constraint that may ultimately limit the reduction in reliance on gas-fired generation in Southern California may be the need for inertia to provide system stability and maintain energy imports at necessary levels.
- Renewable development has implications for potential inertia needs from gas-fired generation as many renewable technologies do not provide inertia to the system. Furthermore, the inertia provided by resources located in the far eastern areas of the state may not contribute to satisfying the SCIT nomogram.

What sub-LCA transmission-related constraints may require gas-fired capacity in "very local" areas, for example, south of the Lugo substation? What transmission upgrades would reduce or eliminate the need for this capacity and are they likely to occur?

Necessary Inputs

Information regarding whether or not the South of Lugo (SOL) constraint (and other "very local" constraints) is likely to be binding over 2017 – 2022, the amount of capacity that would be required to meet it, and what set of resources (existing, potential) will or would contribute to satisfying the constraint. In addition, information regarding the relationship between load conditions and the need to dispatch capacity to meet the constraint would be needed if capacity were required to be dispatched in substantially more hours than were indicated by an unconstrained dispatch.

Source

Information regarding the resources needed to satisfy such constraints and their likely dispatch would have to be provided by the California ISO, as would the impacts of transmission upgrades on the need for them and their dispatch.

Comments

- The SOL and other local constraints are based on contingencies that threaten voltage and/or stability. These constraints typically require the dispatch of one or more specific generating unique to the local constraint, the number of units increases as load increases, and some units may be more effective than others in mitigating the contingency. Typically, the California ISO considers these details to be confidential so developing an analysis that can be sufficiently detailed to provide guidance about the location of new capacity to support these local constraints (given the existing transmission system) is problematic. It is also unclear whether there are any studies recently completed, but not yet translated into operating procedures, or studies still underway that would reveal what transmission system upgrades might reduce or eliminate these local constraints.