ATTACHMENT 2

Energy Division Straw Proposal on LTPP Planning Standards

R.08-02-007, Phase 1

July 2009

**Prepared by CPUC Energy Division,
in accordance with the Phase 1 Scoping Memo
of the 2008 Long-Term Procurement Plan Rulemaking (R.) 08-02-007:**

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Acronyms

AB 32	Assembly Bill 32
AB 380	Assembly Bill 380
AB 57	Assembly Bill 57
ACR	Assigned Commissioner's Ruling
AMI	Automated Metering Infrastructure
CA	California
CAC	California Association of Co-generators
CAISO	California Independent System Operator
CalWEA	California Wind Energy Association
CARB	California Air Resources Board
CARE	Californian's for Renewable Energy
CCGT	Combined Cycle Gas Turbine
CE Council	Community Environmental Council
CEC	California Energy Commission
CEERT	Center for Energy Efficiency and Renewable Technologies
CEQA	California Environmental Quality Act
CHP	Combined Heat and Power
CLECA	California Large Energy Consumers Association
CO2	Carbon Dioxide
Commission	California Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CT	Combustion Turbine
DA	Direct Access
DG	Distributed Generation
DR	Demand Response
DRA	Division of Ratepayer Advocates
E3	Energy and Environmental Economics, Inc
EAP	Energy Action Plan
ED	Energy Division
EE	Energy Efficiency
EM&V	Evaluation, Measurement, and Verification
EPUC	Energy Producers and Users Coalition
FERC	Federal Energy Regulatory Commission
FiT	Feed-in tariff
GHG	Greenhouse Gas
GPI	Green Power Institute
GWh	Gigawatt Hour

IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
IPP	Independent Power Producer
LIP	Load Impact Protocol
LSA	Large-Scale Solar Association
LSE	Load Serving Entity
LTPP	Long Term Procurement Plan
MPR	Market Price Referent
MRTU	Market Redesign and Technology Update
MW	Megawatt
NP-26	North of Path 26
NQC	Net Qualifying Capacity
NRDC	National Resources Defense Council
OIR	Order Instituting Rulemaking
OTC	Once-Through Cooling
PG&E	Pacific Gas and Electric Company
POU	Publicly Owned Utility
PPA	Power Purchase Agreement
PSWG	Permanent Standards Working Group
PV	Photovoltaic
PVRR	Present Value Revenue Requirements
RA	Resource Adequacy
REC	Renewable Energy Certificates
RETI	Renewable Energy Transmission Initiative
REZ	Renewable Energy Zone
RFO	Request For Offer
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SGIP	Self-Generation Incentive Program
SP-26	South of Path 26
SWRCB	State Water Resources Control Board
TEAM	Transmission Economic Assessment Methodology
TEPCC	Transmission Expansion Planning Policy Committee
TeVaR	To-Expiration Value-at-Risk
TMG	Total Market Gross
TRC	Total Resource Cost
TWh	Terawatt Hour
UCS	Union of Concerned Scientists
WECC	Western Electricity Coordinating Council

Executive Summary

Meeting California's aggressive policy goals will require significant infrastructure planning and coordination at a pace and scale unprecedented for the electricity sector. Under Assembly Bill 32, California's electric system is transitioning rapidly towards a radically different paradigm of planning and procurement in which intermittent renewables, such as wind and solar, become a major driver for growth in energy supply, supported by capacity from flexible fossil-fired resources. Meanwhile, once through-cooling ("OTC") mitigation rules[1] may force the retirement of aging coastal plants that provide grid stability and flexible operations to support intermittent renewables, even as 33% renewables policy expects to bring more wind and solar on-line. Achieving these transformations will require careful planning and coordination among the multiple entities with responsibility for various aspects of electric service.

This report sets forth a proposal for the California Public Utilities Commission ("CPUC" or "Commission") to consider in moving forward with an integrated resource portfolio approach as a framework for resource and procurement planning in the 2010 and subsequent Long-Term Procurement Plan ("LTPP") proceedings. The report proposes a framework of standardized, in-depth resource planning analyses in the LTTP proceedings. This framework is developed to ensure that:

- California continues to make progress in achieving its commitment to energy efficiency ("EE"), renewable resources, and greenhouse gas ("GHG") reductions;
- The Commission receives high-quality information from California investor-owned utilities ("IOUs"), so that the Commission can make informed decisions in the 2010 LTPP and other procurement-related proceedings; and
- The IOUs' processes are improved for planning and procurement of new electric generating resources to meet the future needs of electricity users and retail customers in their service areas.

In addition to considering procurement plans for serving bundled load, the scope of this Rulemaking specifically considers long-term resource policy questions which call for an

[1] Pursuant to the federal Clean Water Act of 1972, the State Water Resources Control Board ("SWRCB") is promulgating new rules to mitigate harm from plants that use OTC technology, which could impact over 20,600 MWs of in-state generation, 19 plants located mostly in transmission-constrained load pockets.

"integrated portfolio approach"[2] to resource planning. Indeed, the major challenges facing the IOUs today relate to issues that affect the interests of all electric ratepayers in the state, not just the bundled ratepayers of the IOUs.

The Commission has already taken a number of steps to implement the integrated portfolio approach, including allowing more time for developing the 2010 LTPPs and welcoming substantive input from stakeholders. The Commission has called for several issues to be addressed in the current proceeding:

(a) standardization of resource planning assumptions, practices and analytical techniques ("Planning Standards");[3]
(b) better quantification of EE's effect on the load forecast produced by the CEC;
(c) treatment of uncertain future GHG regulation costs;
(d) development of IOU GHG program inventory reports;
(e) improved treatment of firm capacity from demand-side resources;
(f) consideration of customer risk preference; and
(g) consideration of procurement under the CAISO's MRTU.[4]

While there may be concerns about the impact of new market developments, the Scoping Memo explicitly recognized that:

> Market structures for various resources are being considered or developed in other Commission dockets (e.g., forward capacity markets, GHG cap-and trade, tradable Renewable Energy Certificates ("RECs")) and by other entities (e.g., California Independent System Operator's ("CAISO") Market Redesign Technology Update ("MRTU")). At present, the extent to which generation resources will be procured via these market structures is uncertain, but we anticipate that as they are developed and implemented, the IOUs' reliance on these structures to meet their procurement needs will increase and may require adjustments to (or replacement of) the methodologies being developed in this proceeding. One purpose of the 2008 LTPP is to provide the IOUs with clear direction and a set of expectations for the next round of plans, in the event that the LTPP continues to be a primary vehicle for acquiring new generation. It would be imprudent to assume at this time that other market structures will obviate the need for LTPP-authorized procurement and delay the timely development 2010 LTPP

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[2] See August 28, 2008 *ACR/Scoping Memo*, at p. 8, quoting D.07-12-052, at p. 76.

[3] For a glossary of defined terms, see Appendix F.

[4] August 28, 2008 *ACR/Scoping Memo*, at pp. 1-3.

> policy guidance. Finally, regardless of what the Commission decides on market mechanisms in other proceedings, the IOUs will still need a robust planning process to effectively implement various policy mandates for their bundled customers.[5]

With this context in mind, this report proposes the next step in resource planning, i.e., requiring standardized, in-depth resource planning analyses in order to achieve California's procurement targets through an integrated resource portfolio approach. With these tools, the Commission will have what it needs to (a) inform policy decisions that impact markets, (b) fill gaps where market solutions do not exist, and (c) provide oversight as market solutions progress to ensure that outcomes are within reasonable bounds.

This approach is consistent with the OIR's requirement that policies be aligned with four guiding principles: ensuring reliability, ensuring the lowest reasonable rates by continuing to encourage the development of functional competitive markets (or other market structures), adhering to the EAP loading order, and anticipating AB 32 constraints on IOU electricity portfolios ("Guiding Principles").[6]

Based on these Guiding Principles, Energy Division staff ("staff") has developed a set of Working Principles that refer specifically to the Planning Standards for LTPP to ensure that the goals of the Guiding Principles are met ("Working Principles"):

A. Resource plans should take a realistic view of expected policy-driven resource achievements in order to ensure reliability and track progress toward goals;

B. Resource plans should be compatible with the Commission's goals of advancing markets;

C. Resource plans should be comparable and informative;

D. The Commission should use common assumptions and consistent methodologies across all resource-related proceedings;

E. Resource plans should be informed by an open and transparent process; and

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[5] Id., at p. 6.

[6] *R.08-02-007 OIR*, at p. 8.

F. Resource Plans should consider whether substantial new investment in transmission and flexible fossil generation would be needed to integrate and deliver new resources to loads

Based on these principles, staff recommends the Proposed Planning Standards should have six Foundational Elements:

1. Indicative [7] Resource Plans;
2. Portfolio Analysis;
3. A Renewables and Transmission Study;*
4. A Renewables Integration Study;*
5. A Deliverability Risk Assessment;* and
6. Coordination of Resource Planning.

Building from these Foundational Elements, staff proposes detailed Planning Standards in the following areas: resource planning process, scenarios, metrics, loads and resources tables, assumptions and presentation of information. In general, the detailed Proposed Planning Standards emphasize process and procedure, and to a lesser degree, specific data sources, rather than specify data values or methodologies, which are subject to change. Against this backdrop, staff does recommend specific values on several key Proposed Planning Standards, but only for the imminent 2010 LTPP. This is to memorialize and validate the great body of upfront work that has occurred in the 2008 LTPP, so that the scope (and length) of the 2010 LTPP can be minimized, as much as possible.

One element that is emphasized strongly throughout the Proposed Planning Standards is the need for close coordination both among the Commission's various resource-related proceedings and among the IOUs in developing the system[8] portion of their LTPP analysis. Close coordination is

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[7] In the context of a Commission-adopted Indicative Resource Plan, "indicative" means the detailed, resource- and location-specific data in the resource plan represents a reasonable forecast of a future resource mix, based on the Commission's judgment of the best available information. Like any forecast, interpretation of the results is subject to change as the underlying assumptions and market conditions change over time. The term "indicative" is used in contrast to "prescriptive," which implies that utility procurement is constrained by prescribed types, quantities, and locations of resources set forth in the approved plan. For further discussion, see Section 3.2.1.

[8] "System" refers, individually, to loads and resources within (or deliver to) an IOU's service area or, jointly, to the combined service areas of PG&E, SCE and SDG&E. For a complete definition, see Section 1.3.

* According to the staff proposal, these elements would be partially or wholly completed, for the 2010 LTPP, by entities other than the IOUs, prior to the commencement of 2010 LTPP analyses (See Section 3.8.4).

needed in order to ensure that the Commission has consistent information with which to make important decisions about implementing state policy. Although staff does not propose it at this time, this report discusses the potential benefits and costs of a jointly-filed System Plan. A Joint System Plan could facilitate coordination by presenting a single, system-level analysis developed using a set of stakeholder-vetted inputs and assumptions.

Finally, the report explores possible linkages between the LTPP proceeding and other Commission proceedings and external processes. Staff also offers more specific ideas about conceivable ways that detailed information and analysis from the LTPP System Plan(s) could be used in other forums. Staff purposefully did not limit the scope of these potential linkages to current program designs; indeed, most linkages would require program changes, and in some cases (e.g. RPS), enabling changes to legislation. Further investigation and the ultimate decision whether to actualize these linkages is deferred to the procurement-related dockets themselves, as set forth in the Scoping Memo.[9]

[9] August 28, 2008 *ACR/Scoping Memo*, at p. 4 and footnote #4.

1 Introduction

This report provides staff recommendations for a framework for resource and procurement planning in the 2010 and subsequent LTPP proceedings. The proposed framework is developed to ensure the Commission receives high-quality information from California IOUs, so that Commission can make informed decisions in the 2010 LTPP and other procurement-related proceedings. The proposed framework also improves the processes by which the IOUs plan for and procure new electric generating resources to meet the future needs of electricity users and retail customers in their service areas.

This report is organized as follows. Section 1 provides background and context for the proposal in this report. Section 2 reviews and clarifies basic principles for the Planning Standards proposal, pursuant to the Commission's direction. Section 3 describes the detailed Planning Standards that are proposed for the 2010 and successor LTPP proceedings, beginning with Foundational Elements derived from established principles. Section 4 describes a jointly-filed System Plan as an alternative method of implementing the System Plans that are described in Section 3. Section 5 explores possible linkages between LTPP and other procurement-related proceedings that could be enable by the Planning Standards proposal. Section 6 concludes the report.

1.1 Background

The 2008 LTPP Rulemaking (R.) 08-02-007 will not result in the review and approval of a new set of LTPPs, as has occurred in the past.[10] Instead, the Commission opened the 2008 LTPP proceeding as a means of integrating and refining, "a comprehensive set of procurement policies, practices and procedures underlying long term procurement plans."[11] The recommendations in this report build from the Commission's direction in Phase I of the proceeding to consider, "standardized resource planning practices, assumptions and analytic techniques applied in long-

[10] Since the IOUs' 2006 LTPPs were not approved until December 2007, the Commission concluded that it was not necessary for the IOUs to file a new set of LTPPs in 2008.

[11] *Order Instituting Rulemaking to Integrate and Refine Procurement Policies Underlying Long-Term Procurement Plans*, R.08-02-007, February 2, 2008, at p. 1.

term procurement plans, based on an integrated resource planning framework ("Planning Standards")."[12]

In addition to considering procurement plans for serving bundled load ("Bundled Plans"), the scope of this Rulemaking specifically considers long-term resource policy questions which call for an "integrated portfolio approach"[13] to resource planning. Indeed, the major challenges facing the IOUs today relate to issues that affect the interests of all electric ratepayers in the state, not just the bundled ratepayers of the IOUs. As established in the Scoping Memo for this proceeding:

> Other than the IEPR, which conducts a statewide assessment, the LTPP is at present the only proceeding in which the load serving entities ("LSEs") themselves are required to develop a resource plan, using the best available (including proprietary) data, and evaluate alternative plans under the constraints of current, and future, policy regimes. With proper Commission oversight and public participation, these plans offer California ratepayers and citizens the best opportunity to explicitly evaluate, in an integrated fashion, inherent trade-offs such as cost, risk, reliability, and environmental impact.[14]

The Commission's long-established and primary goals in electric resource planning are to ensure the availability of safe, reliable, and environmentally sensitive electricity service at just and reasonable rates. [15] In addition, climate change is identified as a serious environmental threat that requires immediate and effective action. The Global Warming Solutions Act of 2006 (Assembly Bill ("AB") 32) caps California's GHG emissions at the 1990 level by 2020. Meeting this target will require an 11% reduction from current emissions levels and about a 29% cut in emissions from projected 2020 levels on a statewide basis.[16] Consistent with the EAP "loading order" policy for meeting California's energy needs, increasing EE, Demand Response ("DR"),

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[12] *R.08-02-007 OIR*, at p. 10.

[13] See August 28, 2008 *ACR/Scoping Memo*, at p. 8, quoting D.07-12-052, at p. 76.

[14] August 28, 2008, *ACR/Scoping Memo*, at p. 4.

[15] See *Energy Action Plan II*, October 2005 at p. 2. The CEC, CPUC, and the (now defunct) Consumer Power and Conservation Financing Authority, approved the final Energy Action Plan (EAP I) in 2003. The EAP establishes shared goals and specific actions to ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers. In 2005, a second Energy Action Plan (EAP II) was adopted by both the CEC and the CPUC to reflect the policy changes and actions of the ensuing two years.

[16] D.08-10-037, at p.2.

Distributed Generation ("DG"), Combined Heat and Power ("CHP"), and renewable resources, to the extent possible, and ensuring that these resources are considered appropriately in the long-term procurement process, will reduce California's contribution to climate change. The Commission recently affirmed this approach in D.08-10-037, issued in R.06-04-009, a collaborative proceeding by the Commission and the California Energy Commission ("CEC") to develop and provide recommendations to the CARB on strategies to reduce GHG emissions in the electricity and natural gas sectors. Further, the EAP II explicitly recognized that all cost-effective EE resources should be integrated into the IOU's resource plans on an equal basis with supply-side resource options and that DR programs should be integrated with EE programs.[17]

In EAP I, the Commission and the CEC set a goal of accelerating the 20 percent Renewable Portfolio Standard ("RPS") target from 2017 to 2010. Senate Bill 107 (Stats. 2006, Ch. 464) codified this accelerated goal into law in 2006. In EAP II, the Commission and the CEC targeted steps necessary to achieve higher goals beyond 2010, such as Governor Schwarzenegger's proposed goal of 33 percent of electricity sales by 2020.[18] As the EAP II recognized, "[w]e intend that our increasing reliance on renewable resources within California and from the western region will help mitigate energy impacts on climate change and the environment."[19] Among other actions, the Commission has committed to evaluating and developing implementation paths for achieving renewable resource goals beyond 2010, including 33 percent renewables by 2020 in light of cost-benefit and risk analysis.[20]

1.2 Proceeding History

The 2006 LTPP Decision (D.) 07-12-052 found that the IOUs' LTPPs were (1) deficient in planning for a GHG-constrained world,[21] (2) insufficient in planning for aggressive renewables goals,[22] and (2) so inconsistent in their structures and assumptions that they could not be

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[17] *EAP II*, at p. 3.

[18] Governor Schwarzenegger's Executive Order S-14-08.

[19] *EAP II*, at p. 8.

[20] Id..

[21] See D.07-12-052, at p. 3.

[22] See Id., at pp. 255-256.

compared to one another.[23] In response, the 2008 LTPP OIR directed Energy Division to develop a standardized planning framework in advance of IOU development of the 2010 LTPPs.

The August 28, 2008 Assigned Commissioner's scoping ruling ("Scoping Memo")[24] set the scope for Phase I of the proceeding, including the Planning Standards issue, which is the subject this report. The ruling recounted several milestones that began the process, prior to engaging the assistance of a consulting team, Aspen Environmental Group ("Aspen") and Energy and Environmental Economics, Inc. ("E3") (collectively "Aspen/E3" or "Consultant"). Following is a recap of these and other key milestones leading up to this report.[25]

On May 14, 2008, Pacific Gas & Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E") produced a pre-workshop report on Planning Standards ("*Joint-IOU Report*")[26] summarizing work accomplished in the Planning Standards Working Group[27] to identify opportunities for standardization and seek consensus on specific Planning Standards. A staff summary of the report is provided in Appendix A. The *Joint-IOU Report* and parties' comments heard at a May 21, 2008 workshop to discuss it, form a foundation for further development of Planning Standards.

On June 30, 2008 the Commission's Energy Division retained Aspen/E3 to carry the work forward, under staff direction, ultimately culminating in this report. The consultant's role was to provide technical assistance and facilitate stakeholder involvement leading to a Planning Standards proposal.

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[23] See Id., at pp. 116-117.

[24] See *Assigned Commissioner's Ruling and Scoping Memo on the 2008 Long-Term Procurement Proceeding, Phase I,* dated August 28, 2008.

[25] For a complete reference on 2008 LTPP proceeding activities, see the Commission's procurement website at www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2008/ltpp_schedule.htm.

[26] See *Pre-Workshop Report on Standardized Resource Planning Assumptions and Analytical Techniques for the 2010 Long-Term Procurement Plan* (R.08-02-007), May 14, 2008. The report was served on the service list and is available at ftp://ftp.cpuc.ca.gov/LTPP%20Webposting/Joint%20IOU%20Pre-Workshop%20Report%20on%20Planning%20Standards.pdf.

[27] This working group was comprised of members from PG&E, SCE, SDG&E, Energy Division, and CEC staffs.

On July 10, 2008, Energy Division held a workshop on GHG uncertainty,[28] where the risks associated with various models of GHG regulation emerged as a pivotal theme. Parties agreed to incorporate consideration of these risks into the Planning Standards track, rather than on a separate track. At the workshop, Energy Division described how the Planning Standards track would be subdivided into three sub-tracks, each informed by its own working group: (1) Scenarios and Metrics Working Group, (2) Assumptions and Data Working Group, and (3) 33% RPS Implementation Analysis Working Group.[29] Working groups saw robust participation from over 20 parties to the proceeding, who dedicated dozens of hours to the process.[30] Work group input contributed substantially to this report.

On August 28, 2008, Energy Division held a workshop to begin developing standardized scenarios and metrics.[31] The workshop discussed parties' input, served in response to an August 18, 2008 Energy Division data request, on specific scenarios they contend the IOUs should be required to analyze in the 2010 LTPP. The workshop also established guiding principles for scenario development, defined key terminology, and held preliminary discussions on portfolio metrics. Subsequently, Energy Division and Aspen/E3 facilitated a number of working group

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[28] See *Administrative Law Judge's Ruling Scheduling a July 10, 2008 Workshop on Greenhouse Gas Uncertainty and Requesting Comments*, dated June 6, 2008.

[29] Subsequently, a subgroup, the Electrification Working Group, was formed to consider potential impacts of transportation electrification on resource portfolios; and another subgroup, the Transmission-Constrained Working Group was formed to generate data and analysis in support of a hypothetical 33% RPS case in which long-line transmission cannot be built due to public opposition.

[30] In addition to Energy Division staff and consultants, membership included representatives of the three major IOUs: PG&E, SCE, and SDG&E; environmental groups: Natural Resource Defense Council (NRDC), Union of Concerned Scientists (UCS), Green Power Institute (GPI), and Community Environmental Council (CE Council); ratepayer groups: Division of Ratepayer Advocates (DRA), California Large Energy Consumers Association (CLECA); qualifying facility associations: California Association of Co-generators (CAC), and Energy Producers and Users Coalition (EPUC); renewable developers: BrightSource, Large-Scale Solar Association (LSA), California Wind Energy Association (CalWEA), and GreenVolts; other advocacy groups: Californian's for Renewable Energy (CARE), and the Center for Energy Efficiency and Renewable Technology (CEERT); and state energy agencies: California Energy Commission, and California Independent System Operator.

[31] See *Notice of August 28, 2008 Workshop on Planning Scenarios and Metrics and Data Request*, available at ftp://ftp.cpuc.ca.gov/LTPP%20Webposting/Scenarios%20%26%20Metrics/Scenarios%20%26%20Metrics%20Workshop%20Data%20Request_08-11-08_v2.pdf

meetings to discuss questions and issues surrounding the details of implementing Planning Standards in California. Working group activities continued through March 2009.[32]

As part of this proceeding, Aspen/E3 also conducted a survey of resource planning and procurement practices in other jurisdictions throughout North America ("*Best Practices Report*," see Section 1.5.2).[33] The report included information about both regulated and deregulated jurisdictions, covering vertically integrated and restructured investor-owned utilities, municipal utilities and regional transmission organizations. On September 17, 2008, the draft survey report was circulated to the service list, and comments were served on October 1, 2008.

In parallel, Aspen/E3 worked with Energy Division staff to analyze the cost of and barriers to achieving a 33% Renewables Portfolio Standard ("RPS") by 2020 under different resource portfolio assumptions. On August 26, 2008, the Energy Division held a workshop to kick off the initiative.[34] The 33% RPS Implementation Analysis was launched to satisfy the Commission's requirement that the Energy Division "refine a methodology for resource planning and analysis that will allow [the IOUs] to adequately address the issue of a 33% RPS renewable target in subsequent LTPPs."[35] Preliminary results were presented to the 33% RPS Implementation Analysis Working Group, comments were solicited and incorporated, and a draft report was circulated to the service list on June 12, 2009 ("*Preliminary 33% RPS Report*").[36] All of these efforts have helped to inform the recommendations included in this report.

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[32] Scenarios and Metrics Working Group meetings were held on September 9 and 23, 2008; Assumptions and Data Working Group meetings were held on September 17 and October 7, 2008; 33% RPS Implementation Analysis Working Group meetings were held on December 16, 2008 and February 9, 2009; and an Electrification Working Group meeting was held on March 10, 2009.

[33] Aspen/E3. (2008). *Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California: Draft Report*, September 2008.

[34] See *Energy Division Data Request for Pre-workshop Comments Regarding 33% RPS Implementation Analysis*, www.cpuc.ca.gov/PUC/energy/Renewables/33percentworkshop.htm.

[35] D.07-12-052, at p. 256.

[36] CPUC. (2008). *33% Renewables Portfolio Standard: Preliminary Results*, June 2008. http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/102354.PDF.

1.3 Progress Made to Date and the Broad View of LTPP

Prior to this report, the IOUs came to some important points of agreement which were represented in the May 14, 2008 *Joint-IOU Report* (See Appendix B). These agreements primarily centered on "bundled" aspects of procurement planning, although the IOUs did agree to some aspects of planning for "system," including a uniform set of load and resource tables for physical capacity in the NP-26 and SP-26 regions (See Appendix C). The IOUs are to be commended for these accomplishments, which set the Planning Standards track on solid footing from which to build.

> **Key definitions:** In the context of this report, "**bundled**" refers to loads and resources of the IOU as a Load Serving Entity (LSE). "**System**" refers, individually, to loads and resources within (or deliver to) an IOU's service area or, jointly, to the combined service areas of PG&E, SCE and SDG&E. "**Service area**" is, as defined in D.07-12-052, Tables PGE-1, SCE-1, and SDGE-1, inclusive of bundled, Direct Access and CCA customer load and exclusive of publicly-owned utility load.

While the Joint-IOU agreements are *necessary*, staff believes they are not *sufficient* to satisfy the Commission's stated intent in the Scoping Memo, OIR and recent LTPP decisions, which underscore 33% renewables and AB 32 as key drivers for robust planning. The OIR clearly spells out "one area in particular that the Commission intends to highlight and address in this process is building analytical capability to assess the [EAP] goal of 33% renewables by 2020."[37] Decision 07-12-052 states: "Even in a GHG-constrained world, fossil resources are likely to play a vital role, due to flexibility and reliability attributes; but the IOUs' plans do not demonstrate the analytical rigor to draw this conclusion."[38] These statements suggest broadening the scope of analysis in the LTPP.

This broad view represents an ongoing expansion of the LTPP proceeding's role to include system-wide assessments, which began in R.06-12-13 with D.06-07-029 when the IOUs took

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[37] *R.08-02-007 OIR*, at p. A-9.

[38] D.07-12-052, at p. 6.

responsibility for the backstop procurement function for system reliability, and continues in the R.08-02-007.

Key definitions: This report makes a distinction between "***resource plans***" to ensure system reliability and address policy issues ("System Plans") and "***procurement plans***" to serve bundled customer load ("Bundled Plans"). Whereas resource planning is most relevant *at the system level*; procurement planning is relevant *at the bundled level*. Another important distinction is that resource planning requires long lead-times (5-7 years) to fill net short positions with new resources, while procurement planning occurs on a much shorter timeframe since required resources are already built. ***The bulk (though not all) of this report pertains to standardization of system-wide resource planning practices.***

In the working group process it became quite clear that the issues the majority of parties were most focused on were issues that affect the interests of all electric ratepayers in the state, not just the bundled ratepayers of the IOUs. Parties expressed a desire to see analysis that would reveal information about preferred and feasible resource mixes in alternative future states of the world depending on market and policy uncertainty. For example, EE program costs are recovered through wires charges to all distribution ratepayers (excluding POUs), as are California Solar Initiative ("CSI") and most DR program costs. Further, RPS procurement increasingly requires jurisdictional (or preferably, statewide) coordination, such as the Renewable Energy Transmission Initiative ("RETI"), due to the need for prospective transmission planning and development to access renewables. Finally, the need to identify operating characteristics of new fossil generation required to reliably integrate increasing amounts of intermittent renewables, and replace retiring plants using OTC, has implications that extend beyond the bundled customers. San Diego Gas & Electric's comments reflected a widespread view among parties: "to the extent the Commission is looking at scenario analysis to help guide overall policy direction, an analysis of each scenario looking at the impacts on the *state-wide* portfolio would be beneficial."[39] Thus, staff concludes that scenario analysis should be conducted from the broadest possible perspective.

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[39] *Responses of San Diego Gas & Electric to Data Requests Regarding Planning Scenarios and Metrics*, served August 22, 2008, at pp. 1-2. www.cpuc.ca.gov/NR/rdonlyres/A47CD967-B843-4294-B74A-EFA0B0F270E7/0/SDGEPreWorkshopCommentsScenariosandMetrics.pdf

Staff notes that, in the working groups, IOUs expressed concern that placing too much emphasis on the System Plan could distract attention from the Bundled Plan, which grants the IOUs authority to procure and ensures cost recovery of resources procured on behalf of their bundled customers. A delay in the approval of Bundled Plans could put the IOUs in the undesirable position of procuring from an outdated plan. While these are valid concerns, staff believes the Commission has procedural tools at its disposal to expedite, if necessary, updates to approved Bundled Plans and to grant IOUs provisional authority in the event that significant delays occur.[40] It is also anticipated that the approval phase of the IOUs' Bundled Plans will be substantially reduced by having system planning issues dealt with in a dedicated portion of the LTPP proceeding.

Figure 1 summarizes the discussion above and refers to the May 14, 2008 *Joint-IOU Report* as the starting point for further development of Planning Standards based on the broad view of LTPP. The *Joint-IOU Report* provides a complete set of recommendations to implement the broad view. In sum, while a narrow view of the LTPP proceeding may represent the Commission's explicit direction in past LTPP cycles, a broader view is clearly supported by the Commission's current objectives set forth in the OIR and Scoping Memo.

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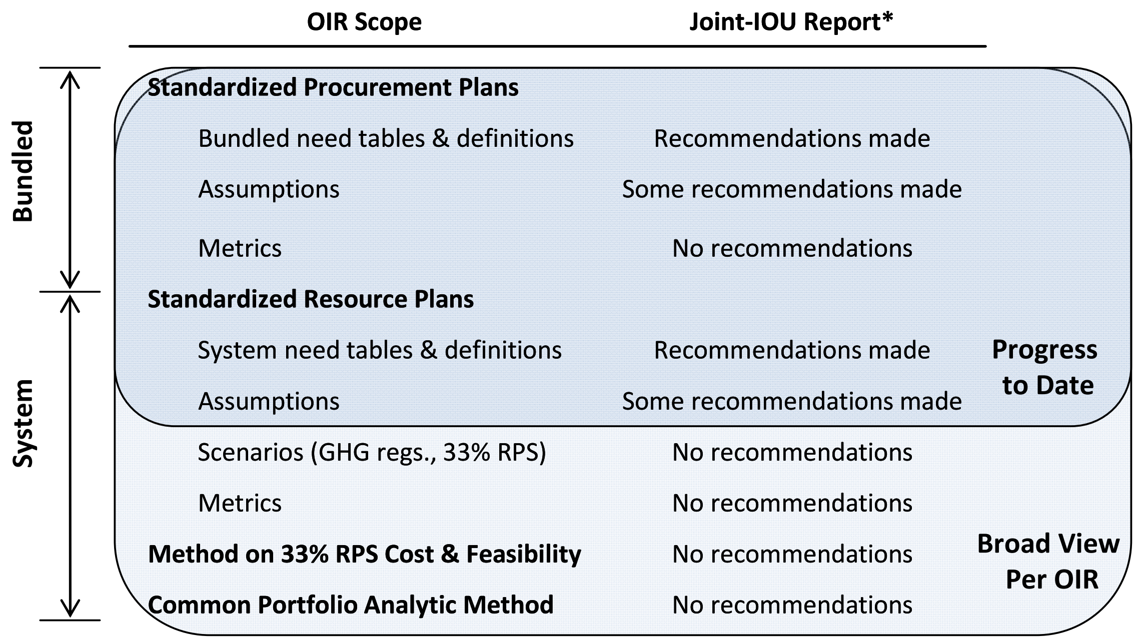
[40] See, for example, provisions for "granting interim procurement authority" in *R.08-02-007 OIR*, at p. 6.



* The Commission has yet to rule on Joint-IOU Report recommendations

Figure 1. Scope of standardization and progress to date prior to this report

1.4 California's Aggressive Energy Policy Goals

California policymakers have established very aggressive goals for the state's electricity sector. The state has established goals for GHG reductions, resource adequacy ("RA"), EE, DR, DG, renewable energy development, combined heat and power ("CHP") systems, and others. Achieving these goals will require the coordinated efforts of policymakers, utilities, regulators, developers, the CAISO, and many others. This section summarizes California's policy goals and describes their impact on utility resource planning. [41]

- **Greenhouse Gas Regulations**: Assembly Bill 32 ("AB 32"), the California's Global Warming Solutions Act of 2006 set binding targets to reduce statewide GHG emissions to 1990 levels by 2020. Governor Schwarzenegger's Executive Order S-3-05 established an even more stringent 2050 target at 80% below 1990 levels.[42] The

[41] See Appendix A of the *Best Practices Report* for a complete summary of the state's relevant energy policies and proposals impacting the LTPP.

[42] Available at http://gov.ca.gov/executive-order/1861/.

CARB, which is tasked with implementing AB 32, has laid out a strategy, informed by recommendations from the CPUC and CEC,[43] to achieve GHG reductions that incorporates many of the electricity policy goals described below to de-carbonize the state's electricity mix.[44] Senate Bill 1368, the Emissions Performance Standard, is another landmark piece of GHG legislation California passed to restrict GHG emissions rates from power plants.

- **Resource Adequacy ("RA"):** The Commission's RA program, adopted pursuant to PUB. UTIL. Code § 380,[45] obligates all jurisdictional LSEs to demonstrate, in year-ahead and month-ahead showings, that they have procured sufficient capacity, including reserves, needed to serve system and local load requirements.
- **Energy efficiency ("EE"):** The Commission's adopted EE goals for the three IOUs estimate savings of over 4,500 MW and 16,000 GWh between 2009 and 2020, the equivalent of nine power plants. The decision also notes that the IOU EE goals broadly align with CARB's statewide goal of achieving 32,000 GWh of EE by 2020.[46] If achieved, this level of EE could nearly eliminate expected growth in statewide electricity demand.
- **Demand response ("DR"):** The state's first Energy Action Plan (EAP) set a goal of reducing peak demand by 5 percent (between 1,500 and 2,000 MW) with price-responsive DR by 2007.[47] The state has not yet achieved this goal. However, the state is still aggressively moving forward to meet the DR goals directly through IOU programs and indirectly through funding Automated Metering Infrastructure ("AMI" or "smart meters").
- **California Solar Initiative ("CSI"):** The million solar roofs initiative, passed in Senate Bill 1 in 2006, seeks to encourage the state to install 3,000 MW of rooftop

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[43] D.08-10-037.

[44] See CARB. (2008). Climate Change Scoping Plan, adopted October 2008.

[45] Assembly Bill 380 (Nunez, Stats 2005, Ch 367); CPUC Rulemaking (R.) 08-01-025 and its successor(s).

[46] D. 08-07-047, at p. 1.

[47] CPUC, CEC, and CPCFA. (2003). *Energy Action Plan I,* at p. 5. Available at: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

solar PV by 2017. For the state's three large IOUs, this translates to a goal of 1,940 MW of new rooftop solar PV by 2017.

- **Combined Heat and Power ("CHP"):** The CARB *Scoping Plan* set a goal of reducing 6.7 million metric tons of CO_2 by 2020 through the expanded use of CHP units.[48] CARB estimates this figure to represent approximately 4,000 MW of new installed CHP generation capacity. The Commission is undergoing an evaluation of this target to match GHG goals and to optimize the existing CHP portfolio.

- **33% Renewables Portfolio Standard ("RPS"):** California law is to meet 20% of retail sales from qualifying renewable energy by 2010. In 2005, California adopted an even higher goal of 33% renewables by 2020.[49] Achieving a statewide target of 33% RPS is estimated to require 75 terawatt-hours ("TWh") of renewable energy,[50] a three-fold increase from the 27 TWh of renewable energy that is claimed by California utilities today.[51] In 2007, California IOUs met about 13% of retail sales with renewable energy.

- **Once-Through-Cooling Mitigation ("OTC"):** Pursuant to the federal Clean Water Act of 1972, the State Water Resources Control Board ("SWRCB") is promulgating new rules to mitigate harm from plants that use OTC technology, which could impact over 20,600 MWs of in-state generation, 19 plants located mostly in transmission-constrained load pockets.[52]

Meeting California's aggressive policy goals will require significant infrastructure planning and coordination at a pace and scale unprecedented for the electricity sector. The Scoping Memo underscores the immense challenge this represents: "Under AB 32, California's electric system is

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[48] CARB. (2008). *Climate Change Scoping Plan*, adopted November 2008.

[49] The 33% RPS by 2020 goal was established by California Gov. Schwarzenegger in Executive Order S-14-08, and has been supported by the CEC and the CPUC in their joint final opinion on strategies to reduce greenhouse gas emissions and meet AB 32 goals (D.08-10-037/#07-OIIP-1) and by CARB in its 2008 *Climate Change Scoping Plan*. Staff also notes that SDG&E committed to 33% RPS as a condition of approval of the Sunrise transmission project, and the Commission accepted that commitment (See D.09-06-018, footnote #8, at p.260).

[50] *Preliminary 33% RPS Report*, at p. 19.

[51] CEC. (2008). *2007 Net System Power Report*, April 2008, CEC-200-2008-002-CMF.

[52] See SWRCB's proposed regulation at www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml.

transitioning rapidly towards a radically different paradigm of planning and procurement in which intermittent renewables, such as wind and solar, become a major driver for growth in energy supply, supported by capacity from flexible fossil-fired resources."[53] Meanwhile, OTC mitigation rules may force the retirement of aging coastal plants that provide grid stability and flexible operations to support intermittent renewables, even as 33% renewables policy expects to bring more wind and solar on-line.

Achieving California's aggressive energy policy goals will require careful planning and coordination among the multiple entities with responsibility for various aspects of electric service.

1.5 Best Practices Approach to Resource Planning

Since the Energy Crisis of 2000-2001, the Commission has continuously improved its oversight of resource planning and procurement to ensure reliable electricity supply at just and reasonable rates, while advancing environmental leadership. Beginning in 2003, for the first time since 1998, the IOUs resumed full responsibility for procurement and "obligation to serve" under Pub. Util. Code § 454.5. The statute requires the IOUs to integrate all-cost effective EE and RPS procurement obligations into general procurement plans, approved by the Commission. The procurement proceeding was originally launched as an "umbrella" proceeding, designed to bring together into one set of analyses the various procurement-related policies that had been handled separately earlier, such as EE, renewables, and load management. Other programs, such as RA, which came later, began in the procurement proceeding (R.04-04-003), but became robust and detailed enough to be split off into its own proceeding as a separate program. This pattern of decentralization in separate proceedings is chiefly one of administrative necessity – the many detailed issues in each resource area cannot be readily accommodated in one "umbrella" proceeding due to the workload implications for both the Commission and parties. Maintaining proceedings with distinct focus on a particular resource has also supported the rapid advancement of policy implementation in each of these areas, such that many of California's policies have earned standing as "best practices." However, there is still a need, at least periodically, to bring all of the resources and policies together to be considered in a

[53] August 28, 2008 ACR/Scoping Memo, at p. 7.

comprehensive way. This is particularly important as it becomes more obvious that the interactions among various policy priorities have the potential to create duplication and potential for excess consumer costs if policies are not closely planned and coordinated.

An integrated portfolio approach is consistent with recommendations of the EAP, as well as CEC's 2007 Integrated Energy Policy Report ("IEPR").[54] The 2007 IEPR undertook scenario analysis studies and portfolio analysis investigations, leading to the Commission's inclusion of these concepts in the OIR. The Commission is collaborating with the CEC in the 2008 LTPP proceeding to implement the 2007 IEPR recommendations on consistency and integration of planning information. Going forward, staff sees the IEPR process continuing to play an important role in providing inputs (e.g., demand forecast) and policy recommendations (e.g., portfolio analysis) to the integrated analysis in the LTPP. Similarly, portfolios adopted or assessed in the LTPP may be usefully integrated into subsequent IEPR studies to draw further conclusions based on common assumptions.

In this proceeding, the Commission set an expectation that the IOUs' resource planning methods should "meet and exceed the high standards Californians expect as pacesetters on energy and environmental issues."[55] Climate change issues and increasingly aggressive "preferred resource"[56] goals have only amplified the need to demonstrate how all these resources fit together to produce a low-carbon energy portfolio that is best for California ratepayers. In short, now is an opportune time to establish a more comprehensive, integrated analysis to guide the Commission's policy-making in the climate change era.

As a first step, the Energy Division engaged Aspen/E3 to survey "best practices" in other regulated and deregulated jurisdictions in order to identify appropriate components of a model for integrated resource planning in California's hybrid market. They also took inventory of the IOUs' current planning practices. Another purpose of the survey was to establish a common understanding of the processes and approaches used in long-term planning and procurement by electric utilities in North America to help guide parties' participation in the LTPP proceeding.

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[54] Cite EAP I, II, and Update.

[55] *R. 08-02-007 OIR*, at p. A-1.

[56] "Preferred resources" are defined as cost-effective EE, DR, clean DG, renewables, and CHP. (See EAP II, at pp. 2 and 4).

The *Best Practices Report* provides many insights into the ongoing development of Planning Standards.[57] The sections below summarize these findings.

1.5.1 Current Resource Planning and Procurement Practices in California

California's current resource planning and procurement practices were developed in parallel with the state's shift from a deregulated market to a "hybrid market" structure – in which deregulated, market-based and regulated, cost-based resource procurement paradigms exist side-by-side – in the early 2000s. Prior to 1998, the Commission regulated through integrated utilities. From 1998-2001, California IOUs were required to procure substantially all of their energy through the California Power Exchange's daily and hourly spot markets. This practice ended with the energy crisis of 2000-2001.

California's subsequent policy actions have emphasized resource diversity (i.e., preferred resources) and the role of long-term contracting as a means of providing reliability and rate stability. Beginning in 2001, the California Department of Water Resources entered into a number of long-term contracts to obtain dependable supply at stable prices. In 2002, California passed Assembly Bill 57 ("AB 57"), requiring the Commission to adopt policies and cost recovery mechanisms for long-term procurement by electrical corporations.[58] Public Utilities Code § 454.5 established a procurement framework in which utilities are authorized to enter into long-term contracts as a means to diversify and optimize their supply portfolio on behalf of utility ratepayers. Further, the statute "eliminate(s) the need, with certain exceptions, for after-the-fact reasonableness reviews of an IOU's prospective electricity procurement performed consistent with an approved procurement plan."[59] The Commission established the LTPP proceeding in response to implement Pub. Util. Code § 454.5.

While Pub. Util. Code § 454.5 originally focused on the procurement needs of the IOUs' bundled customers, the scope of the LTPP proceeding was expanded to include identifying system-wide resource needs. This was required as part of the ten-year forward analysis necessary to ensure sufficient capacity is constructed to meet RA needs. The RA program received explicit

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[57] Aspen/E3. (2009).

[58] AB 57 (Stats. 2002, Ch. 850, Effective September 24, 2004), added P.U. Code § 454.5

[59] P.U. Code § 454.5(d)(2)

legislative direction with adoption of Pub. Util. Code § 380 in 2005. In D.06-07-029, the Commission established an "interim role" for IOU procurement in the LTPP, as a backstop for procurement of system reliability resources. In the same decision, the Commission approved a Cost Allocation Mechanism by which LSEs would share the cost of procuring capacity. Decision 07-07-029 introduced a "system-level" analysis – an analysis of the capacity needs of all loads connected to an IOU's system, including loads under DA or Community Choice Aggregation ("CCA"). Discussions about forming a centralized capacity market are ongoing at both the Commission and the CAISO. If and when such a mechanism is adopted, a system-level analysis will be needed to identify needed new generation, including the type, location, and operating characteristic.

Operating under the auspices of LTPP directives, California IOUs have engaged in resource procurement predominantly through the use of market mechanisms such as Requests for Offer ("RFOs").[60] The LTPPs identify a need for baseload, load-following or peaking resources, and the IOUs procure the identified quantity of resources through an RFO. As long as the utility follows the procurement plan that the Commission approves under its AB 57 authority, the utility is entitled to recovery of its procurement costs through rates. The IOUs separately develop "plans" to procure EE, DR, customer-side DG,[61] RPS-qualifying resources, and other resources in response to policy goals. These plans, approved in other Commission proceedings, are treated as inputs in the LTPP's calculation of the IOUs' "net short" positions.

1.5.2 Resource Planning Practices in other Jurisdictions

Aspen/E3's survey found that long-term resource planning practices vary by jurisdiction according to retail market structure. States that have not deregulated their retail markets, i.e., that continue to regulate the provision of bundled retail electric service by vertically-integrated utilities, have returned to resource planning over the last several years as the momentum toward industry restructuring has slowed. A wide variety of practices is exhibited in these jurisdictions, but the common element is a long-term plan that selects a preferred resource portfolio based on

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[60] A significant amount of new generation was constructed through bilateral contracts and utility ownership outside the RFO process. Most of these projects (e.g., unique and fleeting opportunities) were associated with litigation created by the energy crisis.

[61] In the context of CSI, "plans" refers to the CPUC's program administration plans and the IOUs' Marketing and Outreach and Measurement and Evaluation plans to reach CSI goals.

its superior performance in minimizing cost and risk to retail ratepayers, while satisfying regulatory mandates such as EE and renewable energy targets. The plan is typically informed by a stakeholder process and then filed with the state regulators, who rule on the prudency of utility investments and decide which costs are allowed to be collected through retail rates.

In deregulated jurisdictions, energy procurement is typically conducted via market mechanisms, and utilities for the most part no longer engage in long-term resource planning. Some of the planning functions have moved from state-regulated utilities to Regional Transmission Organizations regulated by the Federal Energy Regulatory Commission ("FERC"). For example, PJM, New England ISO, and New York State ISO plan for system need, but need is met by central auction rather than LSE procurement. Others functions in deregulated jurisdictions, such as project development, are now performed by unregulated wholesale energy market participants. Some planning functions may not be performed at all. Indeed, one of the principal intentions of the move toward restructured markets was to reduce the influence of centralized resource planning and acquisition.

Even in deregulated jurisdictions, however, there is an emerging trend of re-introducing longer-term planning and procurement, due in part to state policies that promote the development of renewable and/or low-carbon resources and the associated need for new transmission infrastructure. For example, some states have recently begun to allow longer-term contracting for renewable resources.[62] Since these resources often require investments in long-line transmission, they typically require the assurance of a utility long-term contract to obtain financing. Further, some states have begun to reconsider whether to allow longer-term contracting, and even utility ownership, of conventional generating resources due to concerns over recent rapid increases in retail rates.[63]

While the experience in other states provides a useful reference, California's "hybrid market" and, more importantly, its aggressive policy goals, differentiate it from other jurisdictions. California is charting a new course in reducing carbon emissions from electric resource

[62] Examples include Connecticut, Illinois, and Pennsylvania. See *Best Practices Report*, Table 5, at p. 34.

[63] Examples include Maryland, Connecticut and Illinois.

procurement, and as such needs to consider carefully what type of planning processes can help to achieve the most benefit at the lowest cost.

1.6 Proposal Structure

This report presents Energy Division staff's proposal to require standardized, in-depth, resource planning analyses for the LTPP proceeding. Figure 2 conceptually portrays the structural components that support the proposal, as well as the proposal itself. The Guiding Principles are high-level principles for the LTPP proceeding found in the OIR. From these, staff developed Working Principles drawn from the OIR and other Commission decisions that pertain specifically to LTPP Planning Standards, which in turn support the Guiding Principles. From these principles, staff constructed Proposed Planning Standards, encompassing a broad range of topics from the overall planning process, to the scenarios that the IOUs should consider, the metrics by which plans should be evaluated, and the inputs and assumptions IOUs should use when conducting their analysis. To help frame these detailed Proposed Planning Standards, staff developed six "Foundational Elements" – basic concepts that the resource plans should address, drawn from the OIR Guiding Principles and more refined, Working Principles. Staff envisions the IOUs implementing the proposal primarily through closely coordinated System Plans. As an alternative to this approach, the report investigates the ramifications of implementing the proposal, in part, through a jointly-filed System Plan covering all of the IOU service areas. The Joint System Plan alternative is not a part of the proposal, however. The report treats each of these components in order, beginning with Guiding Principles.

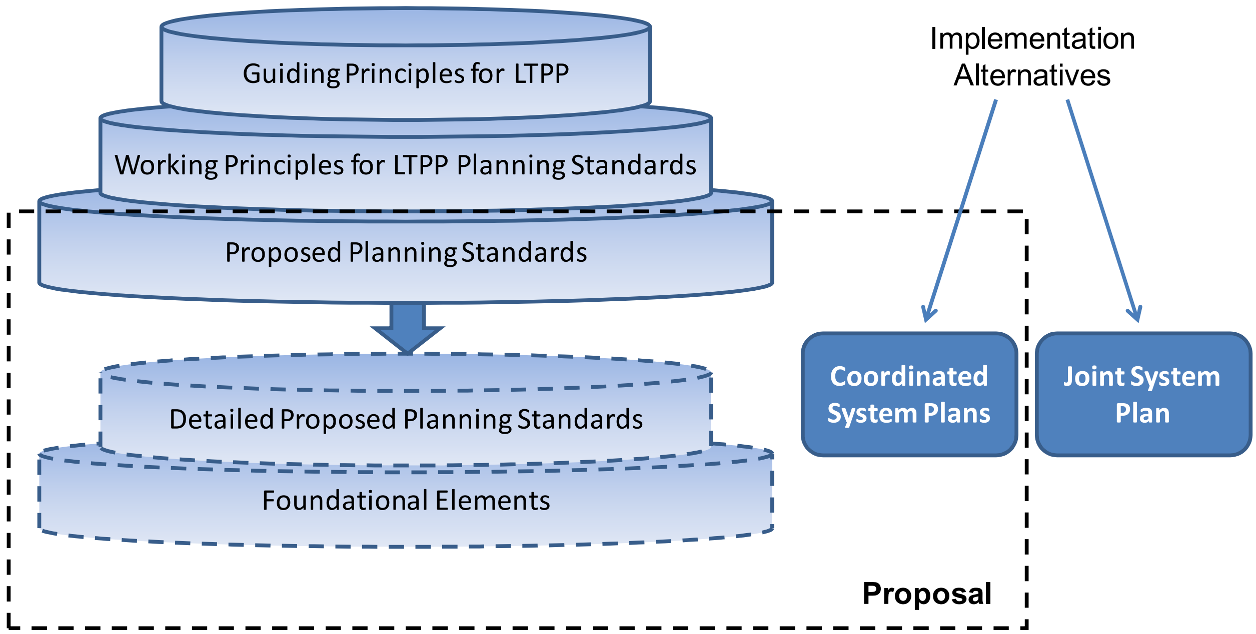

Figure 2. Proposal structure

2 Principles for a Revamped LTPP

The effort to standardize resource planning should be guided by principles set forth by the Commission in the OIR. Staff began by referring to and clarifying these Guiding Principles, as well as directives in the Scoping Memo and Commission decisions, to produce a set of Working Principles for revamping the LTPP planning process. A quick reference table on Guiding Principles and Working Principles is provided in Appendix A. These form the basic underpinnings for the Planning Standards proposal, beginning with Foundational Elements described in Section 3.2.

2.1 Guiding Principles of the LTPP Proceeding

The OIR states that the Commission will focus on policies in the LTPP proceeding that are aligned with four Guiding Principles: "(a) ensuring reliability, (b) ensuring the lowest reasonable rates by continuing to encourage the development of functional competitive markets (or other market structures), (c) adhering to the EAP loading order, and (d) anticipating AB 32 constraints on IOU electricity portfolios."[64] Staff understands these Guiding Principles to refer <u>generically</u> to the overall resource mix and market policies adopted in the LTPP proceeding (e.g., 2010 LTPP).

1. Ensure reliability

Paramount among the Commission's responsibilities is ensuring that sufficient resources are available to maintain system reliability, consistent with the IOUs obligation to serve.[65] Any Planning Standards adopted by the Commission should support this key oversight function.

2. Ensure the lowest reasonable rates

Also important is the Commission's mandate to ensure that public utility rates are "just and reasonable." The Commission has the authority to determine what is "just and reasonable" in the context of other statutory obligations, such as maintaining reliability and protecting the environment. Traditionally, this has meant the cost to efficiently provide power to customers,

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[64] *R.08-02-007 OIR*, at p. 8.
[65] P.U. Code 454.5(d) states: A procurement plan approved by the commission shall…enable the electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates.

including a reasonable return to investors who own the electric infrastructure. In addition, the Commission supports the advancement of competitive markets as a means of reducing costs to ratepayers. Any Planning Standards adopted by the Commission should support the Commission's ability to make effective determinations on cost and encourage least-cost outcomes through the development of competitive markets.

3. Comply with the EAP loading order

The Commission's resource procurement policies are guided by the EAP loading order policy, which calls for filling net short positions, first, with all-cost effective EE, followed by DR, renewables, and DG/CHP. Clean, central-station, fossil generation fills any remaining gap if these resources are insufficient to maintain reliability. The LTPP proceeding is the primary forum to oversee compliance with the loading order, as it is the one place where loading order resource forecasts are combined to determine net short positions for fossil generation. Any Planning Standards adopted by the Commission should enhance its oversight of the loading order policy.

4. Anticipate AB32 constraints on IOU electricity portfolios

With the passage of AB 32, the Commission plays an additional role in overseeing utility procurement in compliance with rules adopted by the CARB limiting GHG emissions to 1990 levels by 2020 and in furtherance of the Governor's 2050 target of 80 percent below 1990 levels.[66] In an October 16, 2008 joint final opinion on strategies to reduce GHG emissions and meet AB 32 goals, the CEC and the Commission recommended accelerating mandatory programs, as well as establishing a market-based emissions trading system (in R.06-04-009). Because GHG regulations will encompass all of the Commission's procurement policies, any Planning Standards adopted by the Commission must enhance its understanding of the complex interactions among short- and long-term GHG reduction strategies.

2.2 Working Principles for LTPP Planning Standards

Staff built from these Guiding Principles using other sources in the OIR, Scoping Memo and Commission decisions in order to establish six "Working Principles." Working Principles refer

[66] Available at http://gov.ca.gov/executive-order/1861/

specifically to the Planning Standards for LTPP that are necessary to ensure Guiding Principles (reliability, cost, loading order, and GHG goals) are met.

A. Resource plans should take a realistic view of expected policy-driven resource achievements in order to ensure reliability and track progress toward goals

The LTPP proceeding is unique from other proceedings because the Commission must judge what is a realistic forecast of delivered resources from policy-driven goals, and then stake system reliability on that forecast through the amount of procurement authority it grants. Indeed, the OIR makes a distinction "between (1) loading order resource goals established in resource-focused proceedings that IOUs must work to achieve and (2) prudent resource planning assumptions that affect need determination, procurement authority, and ultimately system reliability across a six-plus-year time horizon."[67] The fact that LTPP may make more conservative assumptions about resource achievements than the goals themselves does not diminish the goals' value, or indeed, the necessity that the IOUs strive to meet the goals. Rather, the LTPP perspective provides an opportunity for the Commission to take stock of the best available information and track progress towards goals. This principle was consistently applied in the 2006 LTPP, when the Commission adopted the IOUs' own forecasts of DR (which varied from the EAP goal of 5% of peak demand by 2007) and renewables (which varied from the statutorily mandated 20% by 2010). This principle is vital to any Planning Standards adopted by the Commission.

B. Resource planning should be compatible with the Commission's goal of advancing markets

The Commission has signaled its preference for market mechanisms to address industry needs and achieve policy goals. More specifically, the Commission endorses efficient, effective, well-functioning markets with sufficient regulatory oversight. A number of policy initiatives are in play to implement these markets at the Commission and in other venues: e.g., forward capacity markets (R.05-12-013), direct access (R.07-05-025), GHG cap-and-trade (at CARB), Renewable Energy Credits (R.06-02-012), Market Redesign and Technology Upgrade (at CAISO). Thus, any Planning Standards adopted by the Commission should provide information to support a

[67] *R.08-02-007 OIR*, at p. A-21.

variety of market-design end-states. They should not embark on a return to complete regulation. Finally, Planning Standards should be relevant and useful, even when (or if) the current system is replaced by fully competitive markets.

Rather than supplanting markets, these Planning Standards should assist the Commission in making planning decisions where barriers to market mechanisms currently exist. Markets need information to operate efficiently; and current markets do not have sufficient information to respond to multiple regulatory mandates. For example, investors in generation are uncertain where transmission will be built and when; investors in transmission are uncertain which renewable areas will be developed and what effect new generation will have on congestion revenue. In sum, the Commission needs a tool to (1) inform policy decisions that create markets, (2) fill gaps where market solutions do not yet exist, and (3) provide oversight as market solutions progress to ensure that outcomes are within reasonable bounds.

C. Resource plans should be comparable and informative

One of the goals for the LTPP proceeding is to "serve as the forum for comparing resource alternatives against each other, in terms of uniform criteria such as cost, risk, reliability, and environmental impact, in order to optimize California's electric resource portfolio."[68] In a most basic sense, this means that IOU plans should be based on the same forecasting assumptions, such as 1-in-2 load forecast, to prevent inconsistent analyses and reliability levels. This also implies that the LTPP planning process should strive to set resource alternatives on an equal footing with regard to all-in cost, location- and time-dependent energy value, capacity value, grid operability, delivery risk, emissions, and other attributes. In general, the Commission supports "developing tools that allow stakeholders […] to better understand the economic, reliability, and environmental trade-offs between different resource choices – both across different types of supply- and demand-side 'generation' and between generation and transmission."[69] With these tools, the Commission and parties are empowered to protect ratepayers from potential stranded costs due to obsolete fossil generation or underutilized transmission infrastructure, and avoid "crowding out" of preferred resources by fossil procurement.

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[68] *R.08-02-007 OIR*, at p. 8.

[69] *R.08-02-007 OIR*, at p. A-4–A-5.

The ability to compare the IOUs' LTPPs "to each other and work products from other proceedings"[70] is another important rationale for standardization. The *2008 IEPR Update* also emphasized this point when it recommended the 2010 LTPPs "should use standardized inputs (where appropriate)…so that plans … can be easily compared and aggregated".[71] Thus, any Planning Standards adopted by the Commission should facilitate the production of comparable and informative resource plans.

D. The Commission should use common assumptions and consistent methodologies across all resource-related proceedings

One of the goals of the LTPP proceeding is to "coordinate between the various […] policy proceedings (e.g., EE, DR, RPS) and to ensure that they are consistent and coherent."[72] Coordination has two sides in this context: (1) outputs from the LTPP, and (2) inputs to the LTPP. On the outputs side, a number of proceedings at the Commission (as well as external processes at other state agencies) have a need for information about the cost and performance of expected future additions to California's resource mix. To the extent that LTPP is able to unify planning assumptions in a single venue, based on internally consistent methodology, these datasets would be potentially useful to other proceedings and processes.

The LTPP proceeding should not, however, attempt to make determinations about resource goals based upon this information, lest the scope of litigation become unmanageable. Instead, the LTPP should encourage use of the same planning-level data and methodology in other venues, to the extent reasonable. These nuances were clearly described in the Scoping Memo which states: "To the extent that integrated analysis in the LTPP establishes a record and makes significant findings with regard to specific [resource] policies, then the Commission may consider this information in corresponding dockets…The decision of whether to use findings from the LTPP proceeding in another docket is at the discretion of the assigned Commissioner and Administrative Law Judge ("ALJ") for that docket."[73]

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[70] *R.08-02-007 OIR*, at p. A-6.

[71] CEC. (2007). *2008 Integrated Energy Policy Report Update*, CEC-100-2007-008-CMF, February 2, 2008, at p. 57

[72] *R.08-02-007 OIR*, at p. 8.

[73] August 28, 2008 *ACR/Scoping Memo*, at p. 4 and footnote #4.

Similarly, on the inputs side, it makes sense for the Commission to adopt as many assumptions and methodologies from other venues, as is practicable and consistent with the LTPP proceeding's focus on reliability. This has benefits of reducing the LTPP's scope of litigation, and fostering a gradual convergence to a common set of planning-level data. Therefore, any Planning Standards adopted by the Commission should encourage use of common assumptions and methodologies across all resource-related proceedings.

E. Resource plans should be informed by an open and transparent process

The Commission is committed to openness and transparency in its decision-making processes.[74] The OIR states: "a primary objective of this effort will be to provide greater transparency with regard to how resource planning decisions are made."[75] A transparent and stakeholder-vetted process results in lower litigation risk for all parties, including lower risk of protest for the Commission. An open and transparent process also helps to inform markets. Energy Division has embraced this principle in the 2008 LTPP through the extensive outreach and participation fostered in the working group process. Likewise, the Planning Standards proposed for the 2010 LTPP should continue the open and transparent process.

F. Resource plans should consider whether substantial new investment in transmission and flexible fossil generation would be needed to integrate and deliver new resources to loads

Finally, resource plans should evaluate at a high level the extent of any additional infrastructure that is required to meet policy goals in order to get a complete picture of the investment required to deliver new, particularly renewable, resources to loads. These investments include, in particular, flexible fossil generation required to ensure reliable system operations in the presence of new intermittent renewables and transmission needed to deliver new resources to loads. In past LTPP cycles, these investments have been taken as a given, rather than a variable to evaluate. In D.04-12-048, the Commission concurred with the CAISO that "transmission elements of the plans were insufficient to meet our goals and accept[ed] their recommendations

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[74] Subject to confidentiality provisions of D.06-06-066 and D.08-04-023, under SB 1488.

[75] *R.08-02-007 OIR,* at p. A-5.

that future plans should include conceptual scenarios that illustrate the impact of potential generator locations."[76] In 2007, the Commission initiated RETI to identify competitive renewable energy zones and prioritize future transmission development. RETI represents an important step towards aligning transmission and resource planning to achieve policy goals. The Commission "expect[s] the data produced out of RETI […] to be utilized in this proceeding."[77] In addition, the Commission opened a renewable transmission proceeding (R.08-03-009) to examine, among other things, "potential approaches to integration of outputs [from the LTPP]"[78] in the Commission's transmission approval processes.

While R.08-03-009 is investigating possible new linkages between LTPP and transmission permitting based on access to renewables, linkages already exist today. In D.06-11-018 approving the CAISO's Transmission Economic Assessment Methodology ("TEAM") for use in transmission need determinations, the Commission adopted "Principles and Minimum Requirements for the Economic Evaluation of Proposed Transmission Projects […including use of] baseline resource plans and assumptions […] that are consistent with resource plans and system assumptions *used in procurement […] proceedings* (emphasis added)."[79] Any Planning Standards adopted by the Commission in LTPP should facilitate the inclusion of high-level transmission assessments.

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[76] D.04-12-048, FOF 24, at p. 200.

[77] *R.08-02-007 OIR*, at p. A-9.

[78] February 5, 2009 *Administrative Law Judge's Ruling Scheduling a Prehearing Conference and Workshop*, R.08-03-009/I.08-03-10, at p. 5.

[79] D.06-11-018, OP 1 and p. A-2.

3 Proposed Planning Standards

3.1 Introduction

This section describes Planning Standards that staff proposes for IOU system resource plans, and to a lesser extent, bundled procurement plans, including the resource planning process, scenarios and sensitivities, metrics and assessments, data tables and input assumptions, and presentation of information. These standards are informed by stakeholder participation in the workshops and working group meetings and the CPUC's 33% RPS Implementation Analysis, in addition to the Guiding Principles and Working Principles. The standards presented here are proposed *requirements* for IOU plans, unless noted otherwise in this section. The focus in developing these Proposed Planning Standards was on developing a reasonable, long-term approach to resource planning for California. At the same time, staff recognizes that the time to develop the 2010 LTPPs is limited. Hence, in many cases, staff presents two recommendations: a conceptual recommendation for future LTPPs, and a specific recommendation for the 2010 LTPPs. In each case, the recommendation for the 2010 LTPPs represents a specific method of implementing the long-term, conceptual recommendation.

3.2 Foundational Elements for Resource Planning

Before presenting the proposals for detailed Planning Standards, it is useful to consider several key elements that should be incorporated into the IOU resource plans going forward. These are "Foundational Elements," because they form the foundation upon which to construct robust resource planning for California. Derived from the Guiding Principles and Working Principles described above, the Foundational Elements include:

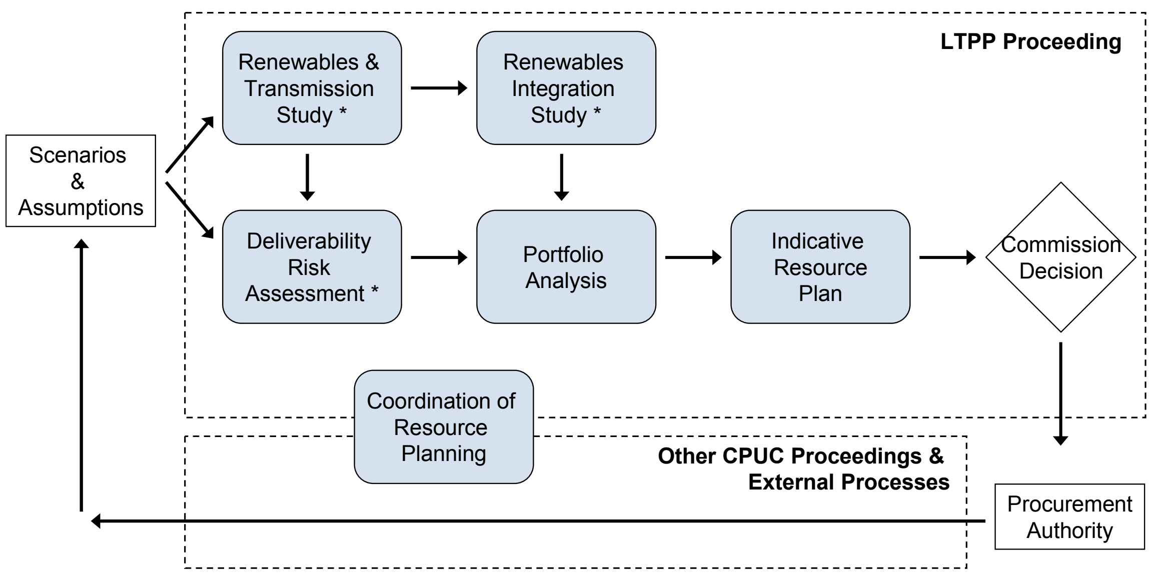
1. Indicative [80] Resource Plans;
2. Portfolio Analysis;
3. A Renewables and Transmission Study;*
4. A Renewables Integration Study; *
5. A Deliverability Risk Assessment;* and

[80] See definition box in Section 3.2.1 below.

* According to the staff proposal, these elements would be partially or wholly completed, for the 2010 LTPP, by entities other than the IOUs, prior to the commencement of 2010 LTPP analyses (See Section 3.8.4).

6. Coordination of Resource Planning.

Figure 3 illustrates the relationships between these Foundational Elements, which are described in further detail in the sections below. Based on defined scenarios and assumptions (see Sections 3.4 and 3.8), a Renewables and Transmission Study (see Section 3.2.3) is conducted to identify and rank cost-effective renewable energy zones in parallel with Deliverability Risk Assessments (see Section 3.2.5) of all resource alternatives. Once the cost of intermittent renewables (wind and solar) is fully quantified through a Renewables Integration Study (see Section 3.2.4), the complete datasets are fed into Portfolio Analysis (see Section 3.2.2), which forms the analytical basis for Indicative Resource Plans (see Section 3.2.1), which the Commission would consider in its decision granting the IOUs' procurement authority. Coordination of Resource Planning (see Section 3.2.6) in other Commission proceedings and external processes is facilitated through Commission adoption of an Indicative Resource Plan.



* Per the Proposed Planning Standards for the 2010 LTPP, these Foundational Elements would be partially or wholly conducted by non-IOU entities and completed in advance of the proceeding; e.g., Energy Division's 33% RPS Implementation Analysis and CAISO's 33% RPS integration study.

Figure 3. Foundational Elements for resource planning

These Foundational Elements form the highest level element of the Proposed Planning Standards presented in this section. Staff proposes that each of the IOUs' system-level resource plans incorporate each of these Foundational Elements. The detailed Proposed Planning Standards that follow are formulated, in part, to ensure adherence to these Foundational Elements. Staff also proposes that Portfolio Analysis and Coordination of Resource Planning occur at the bundled level, as well.

3.2.1 Indicative Resource Plans

Description

Key Definitions: An ***Indicative Resource Plan*** is one in which projected future resource mixes are informational or illustrative only. In this context, "indicative" means the detailed, resource- and location-specific data in the resource plan represent a reasonable forecast of a future resource mix, based on the Commission's judgment of the best available information at the time. Like any forecast, interpretation of the results is subject to change as the underlying assumptions and market conditions change over time. Commission approval of an Indicative Resource Plan does not grant pre-approval or advance rate treatment of resource procurement actions (other than for new resources to meet system and/or local RA requirements); rather, Commission approval indicates that the Commission understands and agrees with the utility's forecast and general resource procurement strategy. Most utility integrated resource plans are indicative plans. Commission approval of a ***Prescriptive Procurement Plan*** authorizes and directs the utility to procure pursuant to specified quantities (or within specified limits) of a specified resource in a specified time frame. IOU bundled procurement plans conducted under the auspices of Pub. Util. Code § 454.5 are prescriptive procurement plans.

California relies on market mechanisms for the bulk of its electric resource procurement. IOUs typically issue renewables solicitations to procure resources to meet RPS targets and all-source solicitations to procure resources needed to meet RA targets. Utilities sign contracts with third-party suppliers based on bids received in the solicitations, and the resulting contract costs are passed through to ratepayers with no utility markup. Utilities have limited control over the bids that they receive in the solicitations, and they earn no profits on the sale of energy procured. In this sense, California utilities are in a different position from utilities in regulated jurisdictions in which utilities have more control over the kinds of resources they procure, whether through building the resources themselves or through targeted wholesale solicitations.

While California utilities cannot know the outcome of a solicitation in advance, the utilities, the Commission, the CAISO, the CEC and other parties need to have a *working forecast* of electric resources available over time to use for planning purposes. This forecast is necessary to ensure that enough system resources are available to provide reliable service to loads, to forecast the demand for new transmission capability, to analyze the potential effects of new policy initiatives such as aggressive RPS requirements, GHG reductions, or retirement of thermal units using OTC, and for a number of other purposes. California must make decisions about what kind of electric infrastructure to build, decisions that depend very much on the kinds of resources that are expected to be connected to the system. Transmission investments, in particular, have a longer lead time than generation investments. The substantial need for investment in electric utility infrastructure requires the best available information about the likely outcomes of market solicitations. Hence, staff recommends that the IOUs develop such information as part of the LTPP process.

In addition, the IOUs have begun to sign contracts outside of the formal solicitation process. All three IOUs have proposed to install hundreds of MW of rooftop solar PV. For example, PG&E has recently stated that it intends to meet 70% of its renewable generation targets with solar resources.[81] Staff believes it is important for the IOUs to demonstrate how these programs fit into their total resource portfolios. This can be accomplished in the LTPP.

Therefore, staff recommends that the California IOUs be required to develop *Indicative Resource Plans* – indicative schedules of resources that are interconnected and on-line by resource type and location for each year of the study period. Resource-type information would include the generator type for supply-side resources (e.g., gas-fired CCGT, wind, solar-parabolic trough, solar PV) as well as the program type for demand-side resources (e.g., customer-side DG, price-responsive DR, EE and CHP). Resources would be characterized by their expected energy production (or savings) by time period and their expected contribution to system peak (net qualifying capacity ("NQC") value). Resources would be identified with sufficient geographical

[81] *PG&E's 2009 RPS Procurement Plan*, filed September 15, 2008 at p. 4; D.09-06-018, Appendix C, at p. C-2.

"granularity" to enable production simulation modeling to identify potential transmission bottlenecks and with sufficient temporal granularity to identify potential over-generation conditions. This level of granularity would also enable new resources to be screened for environmental considerations.

Most working group members supported requiring a level of granularity that is technology-specific with coarse geographic locations; but not project-specific, which parties asserted would be highly uncertain and overly burdensome.[82] Environmental groups (NRDC/UCS, CEERT, and CE Council) were almost universally supportive; e.g., NRDC/UCS argued that this level of information is required to produce "accurate GHG emission estimates for each candidate portfolio" and address "grid operation issues." [83] PG&E supported focusing on "relative [environmental] impacts from resources in broad geographical areas."[84] SDG&E noted that this level of granularity would enable plans to measure the "amount and type of new construction that will be required."[85] Principal opponents of this approach were renewable developers, LSA and CalWEA,[86] and SCE, which went on to say that "if the Commission does identify preferences for geographical locations, it may rank-order [them] to…signal to market participants which areas may be preferred for renewable resource development.[87]

Under this staff proposal, the IOUs would produce Indicative Resource Plans for each of the portfolios analyzed in their LTPPs. The plans would include high-level analyses of system integration and transmission needs associated with each portfolio, in addition to a detailed analysis of the residual system needs. The Commission would adopt these resource plans as "indicative," with one important exception: the Commission's approval would grant IOU authorization to procure (build, contract for, or otherwise cause to be constructed) new resources to meet system and/or local RA requirements. However, Commission approval of other aspects

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[82] These informal comments were made in response to a September 19, 2008 Energy Division discussion paper on environmental issues in the LTPP, served October 3, 2008. www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2008/ltpp_schedule.htm

[83] *NRDC/UCS Comments in Response to Energy Division "Homework Questions,"* at p.1 and 3.

[84] *PG&E's Informal Comments on the LTPP Environmental Issues Paper*, at p. 1.

[85] *SDG&E Response to Questions on Environmental Metrics*, at p. 1.

[86] *LSA and CalWEA Response to "Homework Questions,"* at p. 2.

[87] *SCE's Response to Questions Concerning LTPP Environmental Issues*, at p. 2.

of the plans are not expected to be binding on the IOUs. For example, Commission approval of the LTPPs, based on assumed renewable resource build-outs, would not result in a regulatory requirement to procure the specific quantity of specific resource types at specific locations described in the plan. Rather, the Commission order would constitute an acknowledgement that the resource plan comprises a reasonable forecast of the outcome of utility renewable solicitations and demand-side program achievements, and approval of the possible use of the forecast for other purposes such as determining system need, providing information to other Commission proceedings,[88] and providing information to other planning efforts such as system integration and transmission requirements conducted by the CEC and CAISO.

Approval of indicative planning documents by state utility regulatory commissions is the norm among states that are not deregulated, as the *Best Practices Report* attests. State commissions review and approve utility plans, but this approval does not constitute pre-authorization to procure specific resources in specific amounts. Moreover, utility resource procurement must still undergo a Commission proceeding to determine prudency and establish rate treatment of the investments. California's LTPP process is different in the sense that it *does* result in pre-approval of procurement actions. However, this authorization is only for residual energy and capacity needs. Procurement of renewables and demand-side resources are authorized in different proceedings.

Potential Benefits

There are four primary benefits of developing Indicative Resource Plans as described above.

1. **Accurately identify need for new system resources.** The Indicative Resource Plans would provide information about the expected types and locations of new renewable resources that is necessary to determine resource need. Different renewable resource types perform very differently during system peaks when capacity is needed most. For example, wind resources that produce energy primarily during the night would provide very little reliable capacity for meeting system peaks. A solar thermal resource with thermal storage, by contrast, might be able to produce power at its nameplate rating during system peaks. Since RPS

[88] Other proceedings would make the determination whether/how to use LTPP-related information and analysis.

targets are denominated in energy, rather than capacity, the capacity provided by the RPS portfolio can vary substantially depending on the resources selected. This means that the residual capacity needed to meet forecasted peak demand would also vary substantially. Hence, consistent with Working Principle A, a forecast of the expected outcome of RPS solicitations is a critical input to the calculation of residual resource need.

2. **Identify transmission bottlenecks.** Renewable energy generating facilities must be sited in areas where high-quality resources exist. While California has a number of areas with concentrations of high-quality wind, solar or geothermal resources, most of these areas are located far from load centers. Hence, delivering these resources to California loads will require transmission infrastructure. Resource areas that are located "upstream" of existing transmission constraints may require substantial new transmission construction, while resources that are favorably located might not require any new transmission at all. The issue is complicated by the fact that renewable resources are likely to displace existing fossil resources in the dispatch order due to their very low operating costs; however, the operating characteristics of the renewables would determine how much fossil is displaced in any given hour. While it is difficult to know with any precision what transmission facilities would be needed to deliver a specific resource to load without conducting detailed system impact studies, any study of transmission system needs requires an assumption of specific resources in specific locations. Consistent with Working Principle F, staff believes that the LTPPs are the best vehicle to produce this information for use in transmission planning processes conducted by the IOUs at the Commission, and potentially, by CAISO, Western Electricity Coordinating Council ("WECC"), CEC, and other entities.[89] The LTPPs would take advantage of the best information produced through the

[89] For example, the CAISO's current transmission planning protocol states that "the ISO intends to conduct a more detailed analysis, using the planning assumptions outlined in this Study Plan and the RETI Phase 2 conceptual transmission design, along *with renewables scenarios developed for the California Public Utilities Commission in its current long-term procurement proceeding*, to identify the need for specific transmission upgrades that will enable California LSEs to meet the 33% RPS goals (*emphasis added*)." See *2010 ISO Transmission Plan Final Study Plan*, at p.37. www.caiso.com/2374/2374ed1b83d0.pdf

RETI process, but unlike RETI, the LTPPs would produce specific resource builds to meet specific load targets during each year of the study period. The resources would be specified with sufficient granularity to provide useful information for transmission planning, but must not be so specific as to trigger California Environmental Quality Act ("CEQA") requirements for a given site or corridor.

3. **Identify resources needed for system integration.** In addition to their very different performance during system peaks, different renewable resource types also have different impacts on system operations due to factors such as intermittency, unpredictability and output profiles. It will be increasingly important for utilities, the CAISO and other entities to be aware of the cost of integrating different types of renewable resources and to use that information to inform RPS procurement planning as well as procurement of resources needed for integration such as flexible fossil resources. Indicative Resource Plans could contain operability requirements for resources (fossil, storage, etc) needed to integrate intermittent renewables, such as ramp rate, response time to signal, capacity for a specific duration, etc. This idea is consistent Working Principle C, on informative plans, and Working Principle D, on common assumptions and consistent methodologies. It is discussed in more detail in Section 3.2.4.

4. **Identifying resources potentially avoided through demand-side programs.** Analysis of demand-side programs typically relies on static estimates of avoided resources based on rules of thumb. For example, the Commission's EE proceeding uses the levelized cost of energy from a CCGT (with Time-of-Day valuation factors) as the basis for estimating avoided energy costs, while other proceedings use the net annual carrying cost of a CT as the basis for estimating avoided capacity costs. However, these proceedings might benefit from more detailed information about the resources that are expected to come online during the study period. For example, EE programs would result in avoided procurement of renewable resources, with the accompanying integration and transmission needs, in addition to fossil resources.

5. **Identify need for new local resources.** Geographic specificity of resources will enable the utilities to conduct assessments of need for new resources in local reliability areas. In the 2006 LTPP, SDG&E was granted authority to procure new resources based on local need (and counted it towards the SP-26 zonal need), because their service area is located within a load pocket. Similarly, in the 2010 and subsequent LTPPs, staff anticipates that procurement authority will be based on local as well as system needs; not only for SDG&E, but also for SCE and PG&E. Because SWRCB policies to mitigate OTC are expected to impact reliability in local areas, the LTPP analyses will need to identify appropriate solutions. Using the CAISO's Local Capacity Requirements ("LCR") studies as an input, the IOUs' Indicative Resource Plans would have sufficient geographic granularity to enable determinations of local need and assessments of replacement infrastructure needed to maintain reliability, whilst phasing out OTC plants.

Potential Costs and Risks

Staff has identified the following costs and risks associated with incorporating the concept of Indicative Resource Plans into the LTPP process:

- **Markets-versus-planning debate.** Certain parties (SCE and Competitive Market Advocates) assert that integrated resource planning is incompatible with advancing competitive markets.[90] To be clear, staff sees, at least two continuums on which the markets-planning dichotomy exists: (1) private- versus utility-ownership of generation; and (2) market-based versus planning-induced investment signals. Having the IOUs develop detailed Indicative Resource Plans, affects only the latter by inducing infrastructure investment where market-based price signals do not (yet) exist. Indicative Resource Plans would not dictate *who* (i.e., IPP vs. IOU) should be investing in new resources. Rather, it would signal a need, which the market would continue to provide through competitive solicitations. Until sufficient regulatory certainty exists (on GHG regulations, OTC policies, etc.), private investors will be unable to adequately hedge risks and make investment decision based on reasonable

[90] See, for example, *SCE Comments on Preliminary Scoping Memo*, filed March 17, 2008; and *Comments of the Competitive Market Advocates on the Preliminary Scoping Memo*, filed March 17, 2008.

forecasts. The result is that new generation is primarily being financed by ratepayer-backed long-term contracts. As long as this model persists, the ratepayers need robust planning to ensure that investment decisions made on their behalf are just and reasonable.

- **Added workload and complexity.** Developing Indicative Resource Plans as described above requires additional work and time for Commission staff, IOUs and parties, potentially adding length and complexity to the planning cycle.

- **Misinterpretation.** There is some risk that an Indicative Resource Plan may be viewed as more meaningful than it was intended to be. For example, exclusion of renewable projects in a renewable resource zone may be taken by financiers as evidence about the viability of a given project in that area.

- **Consolidation of decision-making.** Some may be concerned that the Commission would place too much emphasis on the Indicative Resource Plans developed for the LTPPs. If the LTPP generates useful information bearing on other procurement-related dockets, a "slippery slope" argument could be made that the Commission may be tempted to consolidate decision-making power in the LTPP proceeding. However, staff believes that would not occur, since the Commission clearly intends for the umbrella proceeding to "handl[e] procurement policy issues that do not warrant a separate rulemaking"[91] and the Commission currently has separate rulemakings for the other procurement-related issues (e.g., RA, EE, RPS, etc.)

Staff believe that, on balance, the potential benefits outweigh the risks of pursuing Indicative Resource Plans in the LTPP.

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[91] *R.08-02-007 OIR*, at p. 6. See, also, the Commission-adopted "LTPP Scoping Standard" that specifically precludes this from happening: "Any procurement-related issue(s) not already considered in other procurement-related […] may be considered [in the LTPP proceeding] (*Id*., at p. 12)."

3.2.2 Portfolio Analysis

Description

Electric generating resources of different types have different performance profiles. Coal, nuclear (and in California) gas-fired resources produce baseload energy, while hydro and gas-fired units are frequently used for peaking. Gas-fired resources require reliance on volatile natural gas markets, while most renewable resources do not require any fuel. Wind and solar resources have intermittent output profiles, while conventional resources are dispatchable. There is no universal rule about which resource type is more desirable, and the "optimal" resource to add to a given portfolio depends on the resources that are already in the portfolio. This is true especially of a portfolio's performance with respect to risk metrics. For example, renewables may be more desirable for a region that is heavily dependent on gas-fired resources, because a new CCGT would compound the region's existing fuel price risk.

Different portfolios of resources may also perform differently with respect to the cost of firming and integrating intermittent renewable resources. Solar resources produce energy only during the daytime hours, while wind resources in California tend to produce more energy during the nighttime hours. In addition, wind and solar resources that are dispersed across a wide area may result in a combined output that is considerably less variable than a resource base that is concentrated at a single location. Hence, a diverse portfolio of different types of renewable resources at different locations may be less costly to integrate than a less diverse portfolio. However, this reduced integration cost must be weighed against the cost of potentially relying on resources of lower capacity factors in dispersed locations.

As a result of these interactions, the desirability of a particular new resource cannot be analyzed outside the context of an existing resource portfolio. Hence, staff believes that *Portfolio Analysis* must be a Foundational Element of utility resource plans. Portfolio Analysis evaluates the performance of an entire portfolio of resources – including both existing and new resources – under a variety of alternative futures. Portfolio Analysis incorporates multiple elements of resource performance including output profile, on-peak capacity, dispatchability, fuel price volatility, and others. Thus, Portfolio Analysis is essential for producing a "least-cost, best-fit" resource portfolio.

<u>Key Definition:</u> A ***Resource Portfolio*** is a mix of existing and proposed resources that would be constructed to serve a particular group of electric end-users. In the context of System Plans, the resource portfolio serves all customers in an IOU service area. A Resource Portfolio can also be a portfolio of utility-owned or contracted resources procured on behalf of bundled ratepayers. Staff uses this definition when referring to the Bundled Plans.

In utility resource planning, Portfolio Analysis is typically conducted by a utility on behalf of the ratepayers that must ultimately bear the cost of the resources the utility acquires. The utility is interested in procuring a resource mix that provides a reasonable balance between the lowest possible cost and cost stability. While staff recommends that the IOUs conduct Portfolio Analysis on behalf of bundled customers as part of the Bundled Plan, staff also believes that Portfolio Analysis is a useful tool for the System Plan. Specifically, staff recommends that utilities model multiple portfolios of different types of renewable resources at different locations in the state. The Portfolio Analysis should be conducted and metrics calculated from the perspective of all ratepayers in the IOU service area (even though not all ratepayers will bear the costs associated with new IOU resource procurement).

Portfolio Analysis should incorporate the expected performance of demand-side resources as well as supply-side resources because of potential interactions between supply-side and demand-side resources. California's current system of developing targets for different types of resources in different proceedings presents a challenge in ensuring that the resulting resource portfolio is coherent and consistent. For example, as described above, an overabundance of wind resources in a utility portfolio may result in surplus energy during nighttime hours, particularly when combined with programs that reduce nighttime demand such as outdoor or residential lighting programs. High penetration of solar PV resources might result in too much energy during daytime hours, particularly during the late morning when the sun is high in the sky but air conditioning demand has not yet reached its peak level. A balanced portfolio of wind, solar and appropriate demand-side programs – in combination with conventional resources – could avoid many of these issues and result in lower costs for ratepayers. However, program designers need information about the ideal combinations of resources in order to design programs that are consistent with the "expected" portfolio in an Indicative Resource Plan.

Portfolio Analysis is supported by Guiding Principle B, which seeks the lowest reasonable rates, Guiding Principle C, which seeks portfolios that are compliant with the Energy Action Plan loading order, Guiding Principle D, which seeks portfolios that anticipate AB 32 constraints on resource procurement, and Working Principle C, which seeks to ensure that the plans are informative.

Potential Benefits

The principal benefit of Portfolio Analysis is to identify a preferred mix of renewable, conventional, and demand-side resources on both the System and the Bundled levels.

- **Generation portfolio balancing.** Portfolio Analysis for the System Plans will identify a mix of renewable and conventional resources that results in the lowest total portfolio cost including resource capital costs, fuel and O&M costs, intermittent renewable resource integration costs, transmission costs, and all other costs associated with new resource procurement. This will help to ensure that utilities do not over-procure a given type of renewable resources in a given location, driving up the cost of integrating those resources.

- **Supply- and demand-side interactions.** Portfolio Analysis for the System Plans will identify interactions between demand- and supply-side resource programs and provide useful information to other resource-related proceedings about the effect of these interactions on program design and valuation. For example, the System Plans could provide information about time periods in which procurement of RPS resources is expected to result in over-generation conditions, a potentially useful input in EE program design. The System Plans could also indicate whether procurement of RPS resources along with resources needed for integration is likely to result in a surplus of peaking capacity, a potentially useful input into DR program design.

- **"Least cost-best fit" Bundled Plans.** Portfolio Analysis for the Bundled Plans will identify a portfolio of resources that results in a balance of low and stable rates on behalf of bundled customers. Staff notes that the IOUs already do this, as standard practices to manage their bundled resource portfolios, but the Commission sees a need to standardize certain approaches, across the three IOUs, where it makes sense to do so.

Potential Costs and Risks

- **Added workload and complexity.** Conducting Portfolio Analysis in support of the Indicative Resource Plans as described above requires additional work and time for Commission staff, IOUs and parties, potentially adding length and complexity to the planning cycle. Notably, the IOUs conducted Portfolio Analysis, albeit in a more limited form, as part of their 2006 LTPPs.

Staff believe that, on balance, the potential benefits outweigh the risks of requiring Portfolio Analysis in the LTPP.

3.2.3 Renewables and Transmission Study

Description

Meeting RPS targets will be a principal focus of IOU resource planning efforts for many years to come. Meeting a possible 33% RPS target by 2020 will require the development of between 64 TWh[92] and 75 TWh[93] of new renewable energy projects, depending on load growth assumptions. With the exception of distributed resources such as rooftop solar PV, renewable electric generating facilities must be sited in locations with high-quality resources. This means that high-voltage transmission facilities will be required to deliver these new renewable resources to loads. However, new transmission facilities are difficult to site and very expensive to build.

The CPUC and CEC launched RETI in 2008 in order to help identify the transmission projects needed to accommodate state renewable energy goals and facilitate the siting and permitting of transmission and generation facilities.[94] RETI has developed information about the location of high-quality renewable resources in California and neighboring states and potential transmission

[92] *Preliminary 33% RPS Report*, at p. 28

[93] Id., at p. 19

[94] For more information about the Renewable Energy Transmission Initiative, see: http://www.energy.ca.gov/reti/index.html

projects to deliver those resources to California load. However, RETI will not produce a plan for developing the specific quantity of renewable and conventional generating resources and accompanying transmission facilities that are necessary to meet RPS targets while providing reliable service to electric loads at any particular point in time. RETI will, by design, identify more projects than are strictly needed to meet RPS targets at a given point in time. This provides flexibility to account for uncertainty in the ranking methodology and potential environmental and siting hurdles associated with a given transmission project.

The Commission has directed the IOUs to use RETI information in a robust planning analysis of the cost and feasibility of RPS targets.[95] Staff believes that there is a need for a process that compliments RETI and develops a set of alternative plans for simultaneously meeting RPS and other policy goals that can inform the state's transmission planning and siting processes.

Hence, staff concludes that a *Renewables and Transmission Study* should be a Foundational Element of IOU resource plans. The Renewables and Transmission Study would provide information that would be used to develop Indicative Resource Plans. The resource plans could use the information developed through RETI and other processes about the locations of concentrations of high-quality renewable resources and incorporate high-level estimates of the cost of constructing new Transmission Links to a given area. The need for new transmission will depend greatly on the location of new renewable resources.

The primary outputs of the Renewables and Transmission Study would be:

- The location (e.g. by renewable energy zone (REZ)) of high-quality renewable resources in California and neighboring states
- The cost of developing those resources relative to alternatives (i.e.. a renewable supply curve)
- The transmission needs for delivering renewable resources to load for a given location
- The risk factors affecting whether the projects in a REZ would fail or be delayed (e.g. regulatory and market conditions)

[95] D.07-12.052, at p.256.

<u>Key Definition:</u> A ***Conceptual Transmission Link*** is a high-level approximation of a potential transmission project that is useful for investigating whether or not more detailed transmission engineering work is warranted. A Conceptual Transmission Link is *<u>not</u>* a transmission project with a specific route or set of facilities that a utility has proposed or may propose to construct. The Renewables and Transmission Study would investigate Conceptual Transmission Links, but would not get into detailed facility specifications, plans of service, or routes.

The plans would compare the delivered cost of renewable energy from resources in each area and select an illustrative set of resources that results in a resource mix with the best balance of costs and benefits to California ratepayers for each scenario. The study should be coordinated among the IOUs so that IOUs are not implicitly or explicitly assuming reliance on the same set of resources to meet their RPS needs. The study should also incorporate information about POU plans to develop specific renewable resources, to the extent available, to further avoid "double-counting" of available resources. The CPUC's recently-completed 33% RPS Implementation Analysis provides one example for how location-specific resource information could be used to develop an indicative, statewide renewable energy plan. The IOUs could use this methodology or could develop a new methodology relying on newer and better data sources. As discussed above, the resource plans would be indicative in nature. However, the Renewables and Transmission Study would provide valuable information to the CAISO and other parties regarding the location of high-quality, commercially-viable renewable energy resources.

In addition to the CAISO planning process, the Renewables and Transmission Study could also be useful for the Needs Determination aspect of Commission's Certificate of Public Convenience and Necessity ("CPCN") process (See Section 5.1.5). While the CAISO is the lead entity for planning additions to the IOU-owned transmission system, the CPUC has jurisdiction over the permitting of new transmission facilities through its process of issuing a CPCN. These processes generally consider each new transmission project in isolation from any other proposed new projects. However, it is difficult to develop credible, comprehensive assessments of the costs and benefits of a particular transmission project in the absence of any context about how the state would otherwise meet its aggressive RPS and GHG goals. Because it would consider many possible resource areas and methods of meeting aggressive RPS and GHG targets, the Renewable and Transmission Study would provide a context for considering the need for any particular transmission line.

While the CEQA process requires a specific, proposed transmission project to be analyzed in great detail, the Renewables and Transmission Study would be conducted at a much higher level. In working groups, parties almost universally rejected the notion of doing CEQA analysis in the LTPP.[96] Rather than evaluating specific transmission lines with specific configurations along specified routes, the study would analyze Conceptual Transmission Links at much higher level, using stylized assumptions about transmission configuration and about the resources that the transmission line would develop. This high-level approach is necessitated by the lack of firm information about viable projects in a given area and the time and resources that would be required to conduct detailed assessments of the transmission needs associated with a given project or set of projects.

Figure 4 illustrates the distinction between a Conceptual Transmission Link, as proposed here, and an actual transmission project. The Conceptual Transmission Link identifies a general need to transfer energy from a renewables-rich area such as the Imperial Valley to a load center such as San Diego. Some high-level assumptions could be used to develop cost estimates for a Conceptual Transmission Link, but these would not be informed by any decisions about specific routes or line configurations. A CPCN application for a real transmission project such as the Sunrise Powerlink, by contrast, must have very specific information about routing in order to address the environmental impacts associated with the proposed route as well as several alternative routes.

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[96] Californians for Renewable Energy (CARE) was the one exception. See *CARE Response to LTPP Environmental Issues "Homework Questions",* at p. 2.

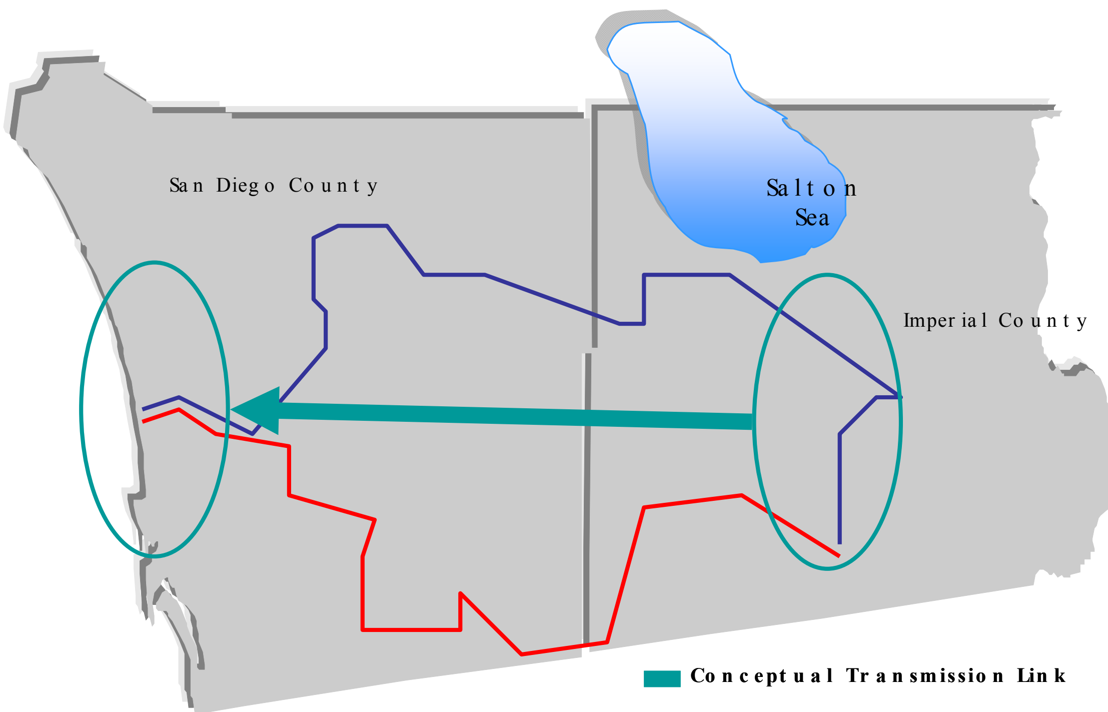

Figure 4. Conceptual Transmission Link between Imperial County and San Diego and alternative routes for the Sunrise Powerlink Transmission Project

A Renewables and Transmission Study is supported by Guiding Principle B, which seeks the lowest reasonable rates, Guiding Principle C, which seeks portfolios that are compliant with the Energy Action Plan loading order, and Guiding Principle D, which seeks portfolios that anticipate AB 32 constraints on resource procurement. It is also supported by Working Principle F, which states that resource plans should consider the effect of resources selected on the need for new transmission investment.

Potential Benefits

There are three main benefits of requiring a Renewables and Transmission Study:

- **Prioritization of renewable zones**. A Renewables and Transmission Study conducted in conjunction with the LTPP cycle would help to identify areas of high-quality renewable resources with a high level of developer interest, acceptable environmental impacts, and reasonable costs for constructing necessary transmission.

- **Avoidance of double-counting.** A coordinated Renewables and Transmission Study would help to ensure that the Resource Plans identify sufficient quantities of *unique* renewable resources (i.e., they avoid double-counting reliance on a given resource) to meet the specified RPS. Avoidance of double-counting would occur among IOUs, and to the extent possible, and between IOUs and POUs as well.

- **System physical infrastructure needs**. A Renewables and Transmission study would identify conceptual resources that might be needed to serve the renewable resource needs of non-IOU LSEs that operate within IOU service areas, such as DA and CCA providers. This would facilitate the process of planning for these customers' physical infrastructure needs including transmission, integrating resources, and capacity resources.

Potential Costs and Risks

Staff has identified the following costs and risks associated with requiring a Renewables and Transmission Study in the LTPP process:

- **Added workload and complexity.** A Renewables and Transmission Study would require a high level of coordination among the IOUs. This increases the workload and complexity of the LTPP proceeding and presents the risk that the IOUs will be unable to agree on a common methodology and set of input assumptions to use in the study. It is also possible that the IOUs may agree on a methodology that is not rigorous enough to advance the process, in order to produce something in response to the Commission's direction.

- **Misrepresentation of resource selection.** Some parties may perceive the Renewables and Transmission Study as "picking winners" among multiple competing renewable resources that are vying for financing and bidding into IOU solicitations. While in our view the Renewables and Transmission Study would provide indicative, yet useful information as inputs into non-binding, Indicative Resource Plans, there is a risk that the study results could be misinterpreted.

- **Confidentiality issues.** The 33% RPS Implementation Analysis relied on confidential, RPS short-listed bid data, compiled by Energy Division, to produce a plausible mix of future RPS resources based on the best available information. If the IOUs were to conduct an analogous study, sharing of confidential information, whether aggregated or otherwise masked, could be challenging. However, since all the relevant data (generator location, resource type, project size) is public once a contract is approved by the Commission,[97] this issue will probably be minor as ongoing solicitations gradually fill the IOUs' RPS resource needs.

Staff believes that, on balance, the potential benefits outweigh the risks of requiring a Renewables and Transmission Study, particularly for the 2010 LTPP when staff recommends relying on the CPUC's 33% RPS Implementation Analysis to serve the purpose.

3.2.4 Renewables Integration Study

Description

As intermittent renewable resources are interconnected to the California grid at higher and higher levels, operators and users of the transmission grid will need to be increasingly mindful of the potential impacts of renewable resources on system operations. Different renewable resource types have different impacts on system operations due to factors such as intermittency, unpredictability and output profiles. When the penetration of renewable resources is very small, it may be possible to ignore the differing system integration needs of various renewable resource types. However, at penetrations approaching 33% of retail sales, the mix of renewable resources can have a substantial impact on system operations. For example, very high penetration of wind resources can result in higher need for resources that can ramp up and down quickly, as well as a surplus of energy during nighttime hours when demand is the lowest. This might require investment in new resources such as fast-ramping fossil resources or energy storage facilities. This need could be exacerbated by EE programs that reduce demand at night. As a result, staff believes that the LTPPs should take into consideration the potential cost of integrating renewable resources into the grid when considering portfolios of renewable resources as part of the LTPPs.

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[97] See D.06-06-066, Confidentiality Matrix.

Staff recommends that that IOUs conduct (or utilize) a *Renewables Integration Study* to provide information into each cycle of the LTPPs. The study should be closely coordinated with (or in the case of the 2010 LTPP, substantially the same as) the CAISO's 33% integration study. The main outputs of the Renewables Integration Study would be:

- The cost, type, and quantity of dispatchable resources that would be needed to integrate intermittent renewables and maintain system reliability
- Resource options (e.g., storage, CTs, etc.) capable of satisfying operational needs

A Renewables Integration Study directly fulfills Guiding Principle 1, on reliability, and Guiding Principle 2, on cost. It is also consistent with Working Principle C, on informative plans, and Working Principle D, on consistent assumptions and methodologies.

Potential Benefits

Staff finds that conducting a Renewables Integration Study and incorporating the results into the LTPPs would result in the following benefits:

- **"Least-cost best-fit" RPS procurement.** Helping to ensure that the RPS procurement process results in a set of renewable resources that can be integrated at a reasonable cost by identifying integration costs associated with different portfolios of renewable resources (e.g., a "high wind" portfolio, a "high PV" portfolio, a "high solar thermal" portfolio, etc.). This information could be used to develop cost factors to apply to different renewable resources at different levels of penetration. By incorporating this information into Portfolio Analysis, the IOUs could generate useful information about mixes of renewable resources that are less costly to integrate. In addition, the Commission could use this information to ensure that RPS portfolios are evenly distributed among technologies, depending on integration requirements.

- **Fossil needs matched to operability requirements.** If alternative portfolios of renewable resources require very different amounts and types of resources for integration, this information would be useful to the IOUs as they develop their fossil procurement plans. For example, a "high wind" portfolio might require substantially more ramping capability than a "high solar" portfolio. Thus, the fossil procurement plan would emphasize fast-ramping resources.

Potential Costs and Risks

Staff has identified the following costs or risks associated with a Renewables Integration Study:

- **Added workload and complexity.** Conducting a Renewables Integration Study in conjunction with each LTPP cycle requires additional work and time, potentially adding length and complexity to the planning cycle. There may be ways to minimize this by relying on external sources such as the CAISO's 33% integration study (at least for the 2010 LTPP), or developing simplified tools or calculators that could be readily updated, such as PG&E's Intermittent Resource Tool, which was presented to the Planning Standards Working Group.

- **Potential inaccuracies introduced.** Staff does not recommend that the IOUs conduct a detailed Renewables Integration Study for each portfolio that it considers during the LTPPs. Instead, the study would be conducted prior to the LTPP analysis and would provide general information about the quantities of resources need for incremental regulation, ramping, unit commitment and other aspects of renewable resource integration. This information might take the form of rules of thumb based on renewable penetration (e.g., X MW of regulation for every Y MW of wind) that would be incorporated into the LTPP analysis. Because these studies would be indicative and high-level, some inaccuracies may be introduced into the LTPP analysis. However, the overall accuracy will improve relative to past LTPPs.

Staff believe that, on balance, the potential benefits outweigh the risks of requiring a Renewables Integration Study of the sort described above, particularly for the 2010 LTPP when staff recommends incorporating the CAISO's 33% RPS integration study results to serve the purpose.

3.2.5 Deliverability Risk Assessment

Description

California has established increasingly aggressive goals for procurement of clean energy resources such as EE and renewable energy over the past several years. Policy-driven resource acquisitions result in environmental benefits and incremental ratepayer savings when they either displace generation from existing resources or defer investments in new resources. However, as policy goals grow more aggressive, it will become more and more critical to distinguish between desirable *goals* that programs are striving to achieve and estimates of expected *achievements* that are needed for prudent utility planning. The paramount goal of utility operations is to ensure reliable service. Policy-driven resource acquisitions can contribute to that goal by diversifying the resource base (e.g., RPS and EE resources are not reliant on fossil fuel supply) and providing additional resources that can be called upon during system emergencies (e.g., DR). However, safeguarding the reliability of electric service in California requires a sober, arguably conservative assessment of the likely achievements of California utility and state agency programs.

To that end, staff recommends that the IOUs conduct, as part of their LTPPs, a *Deliverability Risk Assessment* for all resources identified in the LTPPs. The Deliverability Risk Assessment would evaluate the likelihood that a given resource or set of resources identified in a resource plan would be online and available to meet peak loads during any given year of the study period. The Deliverability Risk Assessment should consider numerous factors such as:

- Timelines for designing, permitting and constructing new resources including potential and likely sources of project delay;[98]
- Supply chain issues, technological maturity, ability to obtain financing and other factors that may affect the ability of resource developers to meet project milestones;
- Participation rates and net savings associated with demand-side programs; and
- Any other factors that may have a bearing on the likely online date of a given resource or set of resources.

[98] See, for example, the timelines prepared for the 33% RPS Implementation Analysis.

Working group members, particularly the IOUs, showed support for this type of assessment; e.g., PG&E stated that "lead time and feasibility, as affected by environmental impacts of building resources, should be considered in determining the need for resources."[99]

The need for a Deliverability Risk Assessment stems principally from Guiding Principle A, which aims to ensure reliability, and Working Principle A, which states that resource plans should take a realistic view of policy-driven resource achievements in order to ensure reliability. As previously noted, this is also consistent with the Commission's approach to the 2006 LTPPs.

Potential Benefits

There are several benefits to requiring a Deliverability Risk Assessment:

- **Increased reliability.** The principal benefit associated with a Deliverability Risk Assessment is increased reliability, that is, a reduced likelihood that there would be insufficient resources available to serve electric loads in the combined IOU service area during every hour of the year. By incorporating realistic, conservative assumptions about resource deliverability, the System Plan will develop evidence that the Commission may elect to rely upon to provide authorization to procure additional resources.

- **Less reliance on uncompetitive procurement.** When resources are short, the Commission may be in the unwelcome position of ordering emergency procurement of new resources through uncompetitive processes. A Deliverability Risk Assessment can help to avoid "just-in-time" procurement, which is not only costly, but also impedes progress towards competitive markets.

Potential Costs and Risks

Staff has identified three primary costs or risks associated with a Deliverability Risk Assessment:

- **Added workload and complexity.** Conducting a Deliverability Risk Assessment requires additional work and time, potentially adding length and complexity to the

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[99] *PG&E's Informal Comments on the LTPP Environmental Issues Paper,* at p. 3.

planning cycle. Assumptions about the efficacy of policy-driven programs may be especially controversial, increasing the risk of contentious litigation.

- **Over-procurement.** A conservative Deliverability Risk Assessment may result in procurement of more resources than are necessary if the policy-driven resource programs are able to deliver at a higher rate than assumed in the study. This would result in higher costs for ratepayers. This risk is endemic in all utility planning processes; there is always a tension between providing reliable electric service and minimizing costs to ratepayers. However, staff believes it is better to assess this risk *explicitly* through a study of resource deliverability than to incorporate it *implicitly* by ignoring deliverability risk.

- **Implied re-litigation of policy goals.** A Deliverability Risk Assessment runs the risk of igniting a debate about the efficacy of state policy within the LTPP proceeding. While staff views a sober, conservative assessment of resource deliverability risk as essential for safeguarding reliability, others may view this as a pessimistic, negative judgment of hard-won policy goals. These disagreements between parties about the achievements of state policy are legitimate and a thorough airing of them should occur as part of the process of setting policy goals. The Deliverability Risk Assessment will not debate the merits of specific policy goals; rather, it will develop a schedule of expected achievements that accounts for uncertainty and risk of non-delivery. However, this distinction may prove too fine to avoid engaging in policy debates during the LTPP proceeding.

Staff believe that, on balance, the potential benefits outweigh the risks of requiring a Deliverability Risk Assessment as described above.

3.2.6 Coordination of Resource Planning

Description

There are a number of proceedings that are ongoing at the CPUC and other state agencies that have a need for information about the cost and performance of expected future additions to

California's resource mix.[100] While each of these proceedings has a need for planning-level data and assumptions, there is currently no single place in which an internally consistent set of planning assumptions is developed and vetted. Rather, each proceeding develops data and inputs as needed. There have been previous efforts at standardization of planning assumptions; for example, many proceedings rely on the natural gas and CO_2 price assumptions developed for the Market Price Referent ("MPR") in the RPS proceeding (R.04-04-026 and successors). Others rely on the avoided cost methodology developed in the Avoided Cost proceeding (R.04-04-025).

Working Principle D states that all of the CPUC's resource-related proceedings should use a consistent set of planning assumptions. As discussed in Section 3.8.1, an Indicative Resource Plan would allow information about the forecasted resource build-out schedule to propagate in a consistent manner through all CPUC proceedings. Staff recommends that the resource planning process take on the task of developing a standard set of planning assumptions that can be propagated to each of the above proceedings, as deemed appropriate in each procurement-related proceeding.

In addition to coordination among the Commission's resource-related proceedings, coordination among the IOUs will result in plans that can be meaningfully compared and aggregated, in keeping with Working Principle C. Such coordination is essential in a number of areas outlined in this proposal. For example, staff believes that the IOUs should use a consistent methodology for evaluating the delivery risk associated with policy-driven resources in order to provide the Commission with consistent information with which to decide the level of procurement authority to grant to each IOU. Staff also recommends that the IOUs develop a coordinated methodology for the Renewables and Transmission Study to ensure that each IOU's plan contains a unique set of renewable resources, i.e., that specific resources such as Tehachapi wind are not counted in more than one IOU plan. And there are a number of other areas in which coordination among IOU plans would provide benefits.

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[100] For example, energy efficiency (R.06-04-010), resource adequacy (R.08-01-025 and R.05-12-013), planning reserve margin (R.08-04-012), renewables portfolio standard (R.08-08-009 and R.06-02-012), California Solar Initiative (R.08-03-008), demand response and advanced metering (R.07-04-041), combined heat and power/AB 1613 implementation (R.08-06-024), applications for utility-owned wholesale distributed generation (A.08-03-015, A.08-07-017, A.09-02-019, A.09-02-13), and others.

Thus, *Coordination of Resource Planning* is the sixth and final recommended Foundational Element. This is supported by Guiding Principle B, which seeks the lowest reasonable rates, Guiding Principle C, which seeks portfolios that are compliant with the EAP loading order, and Guiding Principle D, which seeks portfolios that anticipate AB 32 constraints on resource procurement.

Benefits

Coordination among IOU resource plans and among resource-related Commission proceedings could produce a number of benefits including:

- **Consistent assumptions.** Ensure that EE, CSI, DR and other resource-related Commission proceedings are all working from the same set of assumptions with respect to natural gas prices, CO_2 allowance prices, and other key inputs. This improves the quality of all analyses and helps to ensure that program goals do not conflict.

- **Information feedback.** Provide a feedback loop from the LTPP analysis to the other resource proceedings, informing those proceedings about the potential benefits associated with alternative program designs. Examples of this feedback include the possibility of excess generation conditions due to an abundance of wind generation or the potential for surplus capacity to an abundance of solar generation. These examples are discussed in more detailed in the "Portfolio Analysis" section. Portfolio Analysis would help to identify interactions among various demand-side and supply-side resource programs, but coordination is required to ensure that the IOU resource plans provide information that is useful to these other proceedings.

- **Comparable and informative plans.** Coordination among the IOUs ensures that the IOU resource plans result in a consistent and comparable set of resource portfolios that can be aggregated across the IOU service areas to provide useful information at a higher level. This also provides a public benefit as Commission and parties are more able to interpret the data presented and provide meaningful feedback to the IOUs.

- **Useful information for external planning studies.** Coordination among the IOUs plans will ensure the development of cases that are useful for other planning purposes such as the CAISO's Transmission Planning Protocol, CEC studies of retirement of generators using OTC, and the CARB's implementation of AB 32.

- **Economize intervenor resources.** Parties representing smaller organizations have expressed frustration with the resource requirements of participating in multiple resource and procurement-related proceedings. To the extent that Coordination of Resource Planning facilitates convergence of planning assumptions in procurement-related dockets, their efforts can be economized.

<u>**Costs and Risks**</u>

Potential costs and risks of additional coordination among IOU plans and among Commission proceedings include:

- **Added workload and complexity.** Coordination requires additional work and time, potentially adding length and complexity to the planning cycle. Assumptions that are propagated to other proceedings from the LTPP may have a relatively small impact on the IOU resource plans, but could have a big impact in the other proceedings. Parties with a large stake in the outcome of those proceedings may be more motivated to intervene in the LTPP proceeding and contest the use of planning assumptions they consider adverse.

- **Failure to reach IOU agreement.** Requiring coordination among IOUs invokes the risk that the IOUs may not be able to agree on a study methodology or a set of input assumptions. In this case, the Commission may need to take procedural steps, such as an Assigned Commissioner's Ruling, to resolve any disputes among the IOUs. This might lengthen and complicate the LTPP proceeding, resulting in delayed procurement authorization.

- **Confidentiality issues.** Requiring that IOUs coordinate to develop Indicative Resource Plans that include specific resources coming online at specific times may present potential challenges with respect to safeguarding of confidential data. At any given time, each IOU may be engaged in contract negotiations with a number of potential resource suppliers. While it would be useful to incorporate these proposed projects into the Indicative Resource Plans, care must be taken not to compromise the utility's bargaining position in contract negotiations. On the other hand, Working Principle E, on openness and transparency, suggests that use of public information should be maximized when the IOUs coordinate planning data.

- **Due process challenges.** Commission adoption of an indicative preferred resource plan in the LTPP may make public participation in "downstream" proceedings (e.g., transmission CPCN applications) more difficult. This is the other side of economizing intervenor resources; unsophisticated or one-time intervenors may not come into the LTPP proceeding. But, because resource- or transmission-related findings in the LTPP proceeding would generally not be binding in other proceedings (See Section 3.2.1), intervenors would still have the opportunity to influence outcomes in downstream proceedings.

Staff believe that, on balance, the potential benefits outweigh the risks of requiring a Renewables and Transmission Study.

3.3 Resource Planning Process Overview

The resource planning process, as undertaken in the LTPP proceeding, results in important procurement choices that affect IOUs, ratepayers, the environment, and other stakeholders. Given the importance of the proceeding in helping to shape California's energy future, the LTPP resource planning process requires robust stakeholder input and feedback, guidance from Commission staff and strong participation from the IOUs. The resource planning process recommended here contains each of these elements. Staff recommends that the analysis continue to be led by the IOUs, but that more time be dedicated to the proceeding in order to ensure there is time for high-quality, IOU-led analyses as well as stakeholder feedback and review.

3.3.1 Length of Resource Planning Cycle

California Public Utilities Code requires that, "The commission shall provide for the periodic review and prospective modification of an electrical corporation's procurement plan," but does not specify a required timeline performing this review.[101] Since 2004, the LTPP proceeding has occurred on a biennial basis to ensure coordination with the CEC's IEPR proceeding.[102] While coordination with the IEPR is an important consideration, completing a new LTPP every two years is challenging given the broad scope of issues and the procurement choices at stake. The 2006 LTPP required nearly two years to complete, beginning in early 2006 and concluding at the end of 2007, but only a year or so was devoted to considering IOU plans (the remainder was devoted to the Cost Allocation Mechanism issue). The Proposed Planning Standards would add to the length and complexity of the plans phase of the LTPP, extending to perhaps as much as two years. If planning were to continue on a two-year cycle, the next resource planning process would have had to begin almost immediately. Therefore, staff believes that it may be necessary to move to a three-year planning LTPP cycle; depending on the how the system and bundled analyses are sequenced (see Section 3.3.2 below). It is possible, however, that the Bundled Plan could operate on a more frequent schedule in parallel with the System Plan, if the two were bifurcated. If an IOUs' system net short position significantly changes during the preparation of the LTPP, the Commission could grant interim procurement authority to the IOUs through a publicly vetted compliance update, if necessary. This provision would be similar to the contingency plan built into the current LTPP proceeding (R.08-02-007), which would allow IOUs to procure resources "for a summer peak season that would otherwise have been missed under the revised LTPP schedule."[103]

3.3.2 Resource Planning for System and Bundled Load

There are two distinct, but related components to the LTPP as it currently exists: (1) a System Plan that provides IOUs with authorization to procure (build, contract for, or otherwise cause to be constructed) new resources to meet system and/or local RA requirements for all jurisdictional ratepayers connected to their systems; and (2) a Bundled Plan that authorizes IOUs to procure resources to meet the energy and RA needs of their bundled retail customers.

The System Plan pertains to electric infrastructure needs to provide reliable service at a reasonable cost and risk to ratepayers. Because the System Plan has a broader focus, the System

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[101] P.U. Code § 454.5 (AB 57), sub-section (c)(5)(e).

[102] D. 04-01-050, at p. 175.

[103] *R 08-02-007 OIR*, p. 6.

Plan is the appropriate place to include the bulk of the new analysis proposed herein. Thus, the System Plan would also consider electric infrastructure needs to meet policy goals, such as the RPS and the GHG targets, in the aggregate (as opposed to IOU-specific compliance obligations.)

The Bundled Plan, then, would not require a broad look at energy policy goals and reliability questions, since these are addressed in the System Plan. Rather, the Bundled Plan would address questions such as how individual IOUs are procuring to meet the bundled share of policy goals, how energy procurement will affect bundled ratepayers, what strategies the IOUs have in place to contract for energy and capacity needs and mitigate price risk, and how a re-opening of DA or an increase in CCA could affect bundled customers. This report separately addresses requirements for resource planning for a System Plan and a Bundled Plan because the analyses to support these components are distinct.

Figures 5 and 6 below show an overview of the recommended resource planning process and timeline, under two distinct models: consecutive and concurrent. A more detailed, step-by-step process flow and estimated time schedule is provided in Table 1.

Consecutive Sequencing of System Plans and Bundled Plans

In the 2006 LTPPs, the IOUs performed the system and bundled analyses concurrently. However, staff sees some benefits to completing the system portion of the analysis first, as shown in Figure 5. Under this approach, the IOUs would conduct a System Plan and the Commission would select a preferred portfolio reflecting its judgment about the most likely scenario (See Sections 3.3.3 and 3.4). This scenario and portfolio would be passed to the Bundled Plan, and Bundled Plan portfolios would all be developed within the context of the Commission-approved scenario. The System Plan decision would determine system need and grant authority to procure new system resources. The Bundled Plans would then conduct limited sensitivity analysis around the Commission-selected portfolio, and update the IOUs' procurement strategies accordingly.

The main pros of the consecutive model are:

- **Avoids duplication of effort**. Scenario analysis conducted for the System Plan would not need to be repeated for the Bundled Plan. Robust sensitivity analysis regarding alternative policy and technology futures would be conducted in the System Plan, so there would be no need to address these in the Bundled Plan as well.

- **Simplifies approval of the Bundled Plan.** The Bundled Plan could be substantially simplified by applying many of the same assumptions that had been approved by the Commission for the System Plan. Portfolio Analysis would then be conducted on alternative conventional resource strategies consistent with the renewables and GHG strategy developed through the System Plan.

- **More timely system need determination**. Staff estimates this model would take <u>16.5 months</u> for a System Plan decision granting authority to procure new system resources (See Table 1).

The main con of the consecutive model is:

- **Delayed approval of Bundled Plans.** Staff conservatively estimates this model would take an additional <u>11 months</u> from the System Plan decision (27.5 months total) for the Commission to adopt Bundled Plans. This could be considerably truncated, however, since resource policy questions would not be re-litigated and since few parties (i.e., non-market participants) would likely intervene in the proceeding. As such, some process steps identified in Table 1 could potentially be combined and/or accelerated. Until Bundled Plans are finally approved, the IOUs to update their plans by advice letter to address any imminent issues, as authorized by D.07-12-052. Indeed, it is conceivable that Bundled Plans could be approved by advice letter, to the extent that the Commission adopts an AB 57 Procurement Rulebook as anticipated in Phase 2 of R.08-02-007. In the event that system need and procurement rules already established by previous Commission decisions, the scope of issues in addressed in Bundled Plans could be significantly reduced. Therefore, staff considers 11 months to be a very conservative estimate of the time required for Bundled Plans under the consecutive model.

Concurrent Sequencing of System Plans and Bundled Plans

Alternatively, the System Plan and Bundled Plan could continue to be undertaken concurrently as they have in the past, as shown in Figure 6. In general, scenario analysis and robust sensitivity analysis would need to be conducted for <u>both</u> System Plans and Bundled Plans, because the Commission would not adopt a preferred portfolio until the end of the planning process. It may be possible for the IOUs to work together with stakeholders and the Energy Division to develop an appropriately narrow scope for the Bundled Plans, based on the work conducted for the System Plan(s).

The main pros of the concurrent model are:

- **One decision, instead of two.** It ensures that both the system and bundled analyses are completed simultaneously, as neither piece of analysis is dependent on the outcome of the other.

- **Coordination.** This option may enable the two analyses to be more closely coordinated.

The main cons of the concurrent model are:

- **Duplication of effort.** The IOUs would most likely need to fully develop system and bundled portfolios consistent with the scenarios described below in Table 1. While staff does not believe it is strictly necessary for analytical purposes to model the portfolios at both levels, it may be unavoidable given the timing of the procedures.

- **Delayed system need determination.** Staff estimates this model would take <u>23 months</u> for a decision adopting both System Plans and Bundled Plans and granting authority to procure new system resources (See Table 1). This is mainly due to requisite duplication of analytical efforts and documentation of both plans. This model would probably require changing the LTPP to a three-year cycle, which raising issues coordinating with the biennial IEPR and load forecast.

This report does not make a recommendation at this time as to whether the consecutive analysis option or concurrent analysis option is preferable.

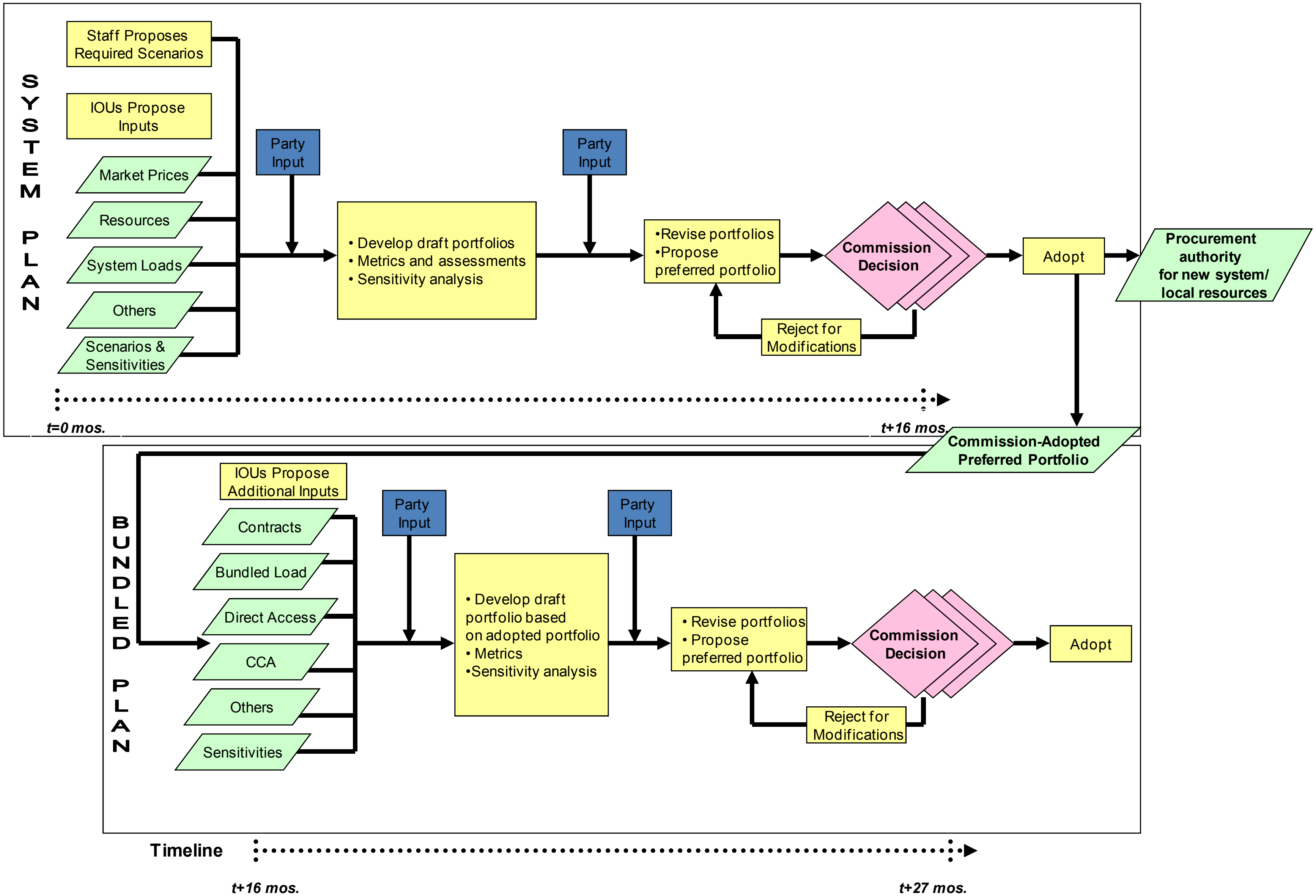

Figure 5. Resource planning process and timeline under consecutive System Plans and Bundled Plans

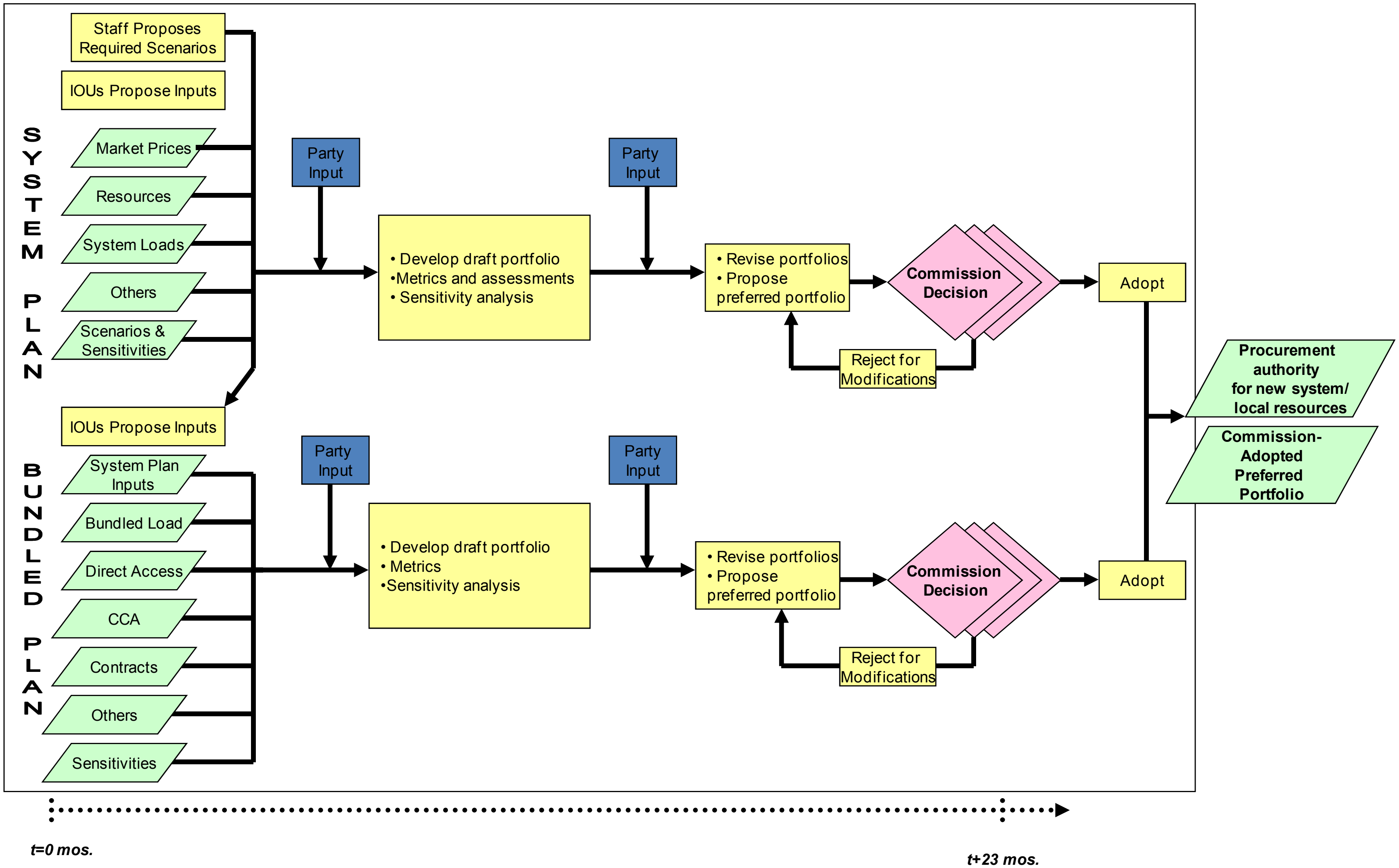

Figure 6: Resource planning process and timeline under concurrent System Plans and Bundled Plans

Table 1. Detailed process steps and estimated schedule for consecutive and concurrent sequencing of System Plans and Bundled Plans.

Consecutive

	Process Steps		Mos.
	System Plan		
Scenarios & Assumptions	**S1. Draft required scenarios.** Staff proposes required scenarios which the IOUs will investigate, in consultation with parties..	**S2. Draft *system* assumptions.** IOUs develop coordinated *system* inputs, assumptions and sensitivities, in consultation with sta and parties.	3 [1]
	S3. Party input. IOUs and parties provide written comments on staff-proposed required scenarios and IOU-proposed *system* inputs, assumptions, and sensitivities.		1.5 [1]
	S4. Final required scenarios and *system* assumptions. Staff finalizes required scenarios, and *system* inputs, assumptions, and sensitivities, by Energy Division letter of approval.		1.5 [1]
Portfolio Analysis	**S5. Draft *system* portfolios.** IOUs develop draft *system* portfolios for each scenario. IOUs apply evaluation criteria and sensitivity analyses to each portfolio to help select a preferred 'least-cost, best fit' draft portfolio for each scenario.		2
	S6. Party input. IOUs present draft *system* portfolios to parties and staff, and explain selection process. Parties comment.		1
	S7. Final *system* portfolios and portfolio selection. IOUs make any adjustments to the draft *system* portfolios, as needed, based on feedback from staff and parties. IOUs develop their final *system* portfolios and select a single, preferred *system* portfolio from among the final portfolios.		1

Concurrent

Process Steps		Mos.
System Plan and Bundled Plan		
S1/B1. Draft required scenarios. Same as consecutive model.	**S2/B2. Draft assumptions.** IOUs develop coordinated (for *system*) and individually generated (for *bundled*) inputs, assumptions and sensitivities, in consultation with staff and parties.	4 [1]
S3/B3. Party input. IOUs and parties provide written comments on staff-proposed required scenarios and IOU-proposed *system* and *bundled* inputs, assumptions, and sensitivities.		1.5 [1]
S4/B4. Final required scenarios and assumptions. Staff finalizes required scenarios, and *system*[2] inputs, assumptions and sensitivities, by Energy Division letter of approval.		1.5 [1]
S5/B5. Draft portfolios. IOUs develop draft *system* (and corresponding *bundled)* portfolios for each scenario (i.e., scenario analysis is repeated for System and Bundled Plans). IOUs apply evaluation criteria and sensitivity analyses to each portfolio to help select a preferred 'least-cost, best fit' draft portfolio for each scenario.		3
S6/B6. Party input. IOUs present draft *system* (and corresponding *bundled)* portfolios to parties and CPUC staff, and explain selection process. Parties comment.		2
S7/B7. Final portfolios and portfolio selection. IOUs make any adjustments to the draft *system* (and corresponding *bundled)* portfolios, as needed, based on feedback from CPUC staff and parties. IOUs develop their final *system* (and corresponding *bundled)* portfolios and select a single, preferred *system (*and corresponding *bundled)* portfolio from among the final portfolios.		2

Consecutive

Phase	Process Steps	Mos.
	System Plan	
Filing	**S8. System Plan filed.** IOUs each present their proposed *system* portfolios, as well as the selection process for the preferred portfolio, to the Commission in their *System Plan* filing.[3] The filing documents results of the evaluation criteria and sensitivity analyses applied to each final portfolio.	2
Filing	**S9. Hearings.** The Commission holds hearings on disputed issues of fact in the *System Plan* filings.	1.5
Commission Decision	**S10. Proposed Decision.** The Commission issues a Proposed Decision on the IOUs' *System Plan* filings. The PD addresses whether to adopt each IOUs' preferred *system* portfolio, adopt an alternative portfolio, or reject the filing for changes. When adopted by the Commission, the System Plan decision would grant the IOUs authority to procure new resources to meet *system* and/or local RA requirements.	2
Commission Decision	**S11. Comments on PD**. Parties file comments on the PD.	1
Commission Decision	**S12. Final Decision.** The Commission rules on the IOUs' System Plans	
	Total Time Elapsed for System Plan	**16.5**

Concurrent

Phase	Process Steps	Mos.
	System Plan and Bundled Plan	
Filing	**S8/B8. System and Bundled Plans filed.** IOUs each present their proposed system (and corresponding bundled) portfolios, as well as the selection process for the preferred portfolios, to the Commission in their LTPP filing.[3] The filing documents results of the evaluation criteria and sensitivity analyses applied to each final portfolio. The Bundled Plan demonstrates how each IOU plans to comply with procurement rules and loading order policy goals.	3
Filing	**S9/B9. Hearings.** The Commission holds hearings on disputed issues of fact in the LTPP filings.	2
Commission Decision	**S10/B10.Proposed Decision.** The Commission issues a PD on the IOUs' LTPP filings. The PD addresses whether to adopt each IOUs' preferred *system* (and corresponding *bundled*) portfolio, adopt an alternative portfolio pair, or reject the filing for changes. When adopted by the Commission, the LTPP decision grants the IOUs authority to procure new resources to meet *system* and/or local RA requirements; and specifies limits of IOU authority to procure energy/capacity to serve *bundled* load.	3
Commission Decision	**S11/B11. Comments on PD.** Parties file comments on the PD	1
Commission Decision	**S12/B12. Final Decision.** The Commission rules on the IOUs' System and Bundled Plans.	
	Total Time Elapsed for System and Bundled Plan	**23**

– End –

Consecutive

Phase	Process Steps	Mos.
	Bundled Plan [4]	
Assump-tions[2]	**B1. Draft *bundled* assumptions.** IOUs develop draft *bundled* inputs, assumptions, and sensitivities, based on the approved *System Plan*.	1
	B2. Party input. IOUs present draft *bundled* inputs, assumptions, and sensitivities to parties and staff. Parties comment.	1
Portfolio Analysis	**B3. Draft *bundled* portfolios.** IOUs develop draft *bundled* portfolio, based on approved *System Plan* and vetted input assumptions;[2] and apply evaluation criteria and sensitivity analyses.	1
	B4. Party input. IOUs present draft *bundled* portfolio to parties and staff, explaining why it is "least-cost best-fit." Parties comment.	1
	B5. Final *bundled* portfolio. IOUs make any adjustments to the draft *bundled* portfolio, as needed, based on feedback from staff and parties.	1
Filing	**B6. Bundled Plan filed.** IOUs present their *Bundled Plan* with proposed preferred portfolio, as well as the selection process for the preferred *bundled portfolio*, to the Commission in their filing. The *Bundled Plan* demonstrates how each IOU plans to comply with procurement rules and loading order policy goals.	2
	B7. Hearings. The Commission holds hearings on disputed issues of fact in the *Bundled Plan* filings.	1
Commission Decision	**B8. Proposed Decision.** The Commission issues a PD on the IOUs' *Bundled Plan* filings. The PD addresses whether to adopt, modify or reject (for changes) the IOUs' *Bundled Plan*. When adopted by the Commission, the *Bundled Plan* decision species the extent of each IOUs authority to procure energy/capacity to serve bundled load.	2
	B9. Comments on PD. Parties file comments on the PD.	1
	B10. Final Decision. The Commission rules on the IOUs' Bundled Plans.	
	Total Time Elapsed for Bundled Plan[4]	**11**

Notes:

[1] For the 2010 LTPP, required scenarios will have been determined in the predecessor 2008 LTPP, but some assumptions would still need to be developed and vetted, including (1) retirements and additions, (2) DR load impacts; (3) CHP cost and potential assumptions; (4) updates to renewable resource availability, cost and performance assumptions; (5) new generation, tax and financing assumptions; (6) biomass and coal prices; (7) GHG policy assumptions; and (8) other assumptions for Bundled Plans only including re-contracting rates, electricity market prices, etc.

[2] Bundled inputs and assumptions are not anticipated to require Energy Division approval due to legitimately unique characteristics of each IOU's bundled load and resource portfolio.

[3] Section 4 describes the "Joint System Plan" alternative, which, if pursued by the Commission, would have provisions for what to do in case the IOUs cannot reach agreement on every aspect of the joint filing, e.g. an opportunity to file "dissenting opinions" on minor disputed issues.

[4] Staff believes this is a conservative estimate, because the Bundled Plan phase could be considerably truncated due to (1) resource policy calls having already been made in the System Plan and (2) the small number of mostly non-market participant parties that are likely to intervene in the bundled phase. It may be possible to process the Bundled Plans by advice letter.

3.3.3 Scenario Development

Staff recommends that the IOUs be required to consider a number of scenarios in their resource plans, and develop a least-cost, best-fit portfolio for each scenario. The assumptions underlying each scenario will help to guide the resource selection for a portfolio. Each scenario should be designed to test a specific policy or market question.

Figure 7 below shows the process of developing and analyzing portfolios of resources that IOUs would use in their 2010 LTPPs. This general framework closely resembles the recommendations jointly submitted by the three IOUs in the working group process.[104] Non-IOU parties generally agreed, provided sufficient stakeholder input is included to vet draft assumptions and portfolios, prior to finalizing them. The IOUs would first, in consultation with the staff and stakeholders, develop *scenarios* to analyze. For each scenario, the IOUs would develop one or more *portfolios*.

Key definitions: A ***scenario*** is a possible future; it encompasses assumptions about policy requirements, market realities and resource development choices. A ***portfolio*** is a set of electric resources, both supply-side and demand-side, that provide electric service to retail loads. Staff uses the term "portfolio" in this context to mean the mix of resources that are developed to serve all system ratepayers, rather than the narrower sense of a mix of resources procured to serve bundled load. Sensitivity analysis (or "***sensitivity***") is a test to measure the change in output variable (e.g., cost) due to a change in input variable (e.g., gas price). In a sensitivity, the portfolio composition remains fixed.

The plans would analyze the performance of each of these portfolios with respect to cost, risk, environmental impacts, and other criteria, across scenarios (See Section 3.5). The selection of one or more 'least-cost, best-fit' resource portfolio for a given scenario is not a mechanical process, but one that requires judgment and discretion. Ideally, the development of each portfolio will take into consideration cost, risk and environmental

[104] See *Joint Response of SDG&E, SCE, and PG&E to ED/CPUC "Homework," Attachment 1: Resource Planning Analytical Process*, served September 5, 2008. Available at www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2008/ltpp_schedule.htm.

impacts, although these criteria will also be the basis for evaluating portfolios against one another. Each portfolio should meet minimum reliability criteria (See Sections 3.5.1 and 3.5.2). Staff recommends that the IOUs present in a clear and transparent way their criteria for selecting a 'least-cost, best-fit' resource portfolio for each scenario.

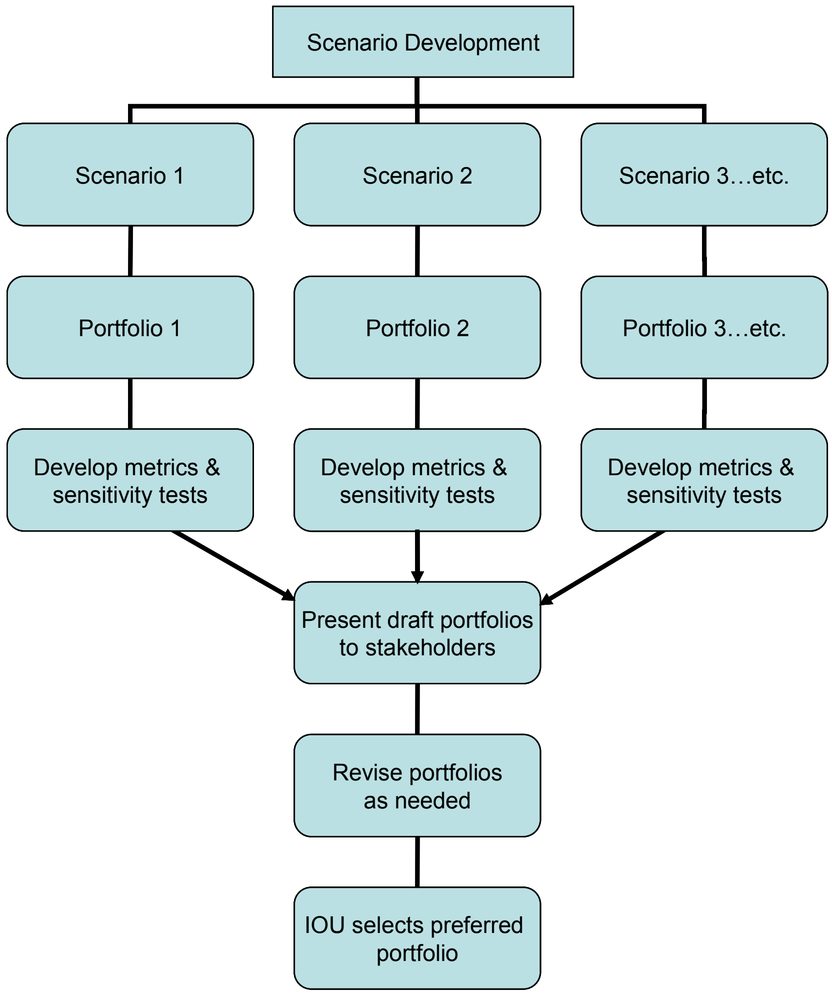

Figure 7: Portfolio development and evaluation process for system plans

Based on those evaluations, and in consultation with stakeholders, the IOUs would select a "preferred portfolio" of resources that performs well across a number of evaluation criteria and scenarios. The IOUs would then present it to the Commission for approval. Staff does not recommend that the Commission require specific algorithms for optimizing among the different criteria, or for handicapping the likelihood of one scenario occurring rather than another. Rather, staff recommends that the IOUs select a preferred portfolio based on their own evaluation of the relative merits of each portfolio and articulate the reasons for their selection to the Commission. The IOUs would also present the alternative portfolios they did not select, their scoring and ranking of those portfolios, and a detailed rationale for selection of the preferred portfolio. The Commission could then approve the IOUs' preferred portfolios, substitute an alternative portfolio, or reject the plan for further study by the IOUs. Details for each of these steps are provided in the sub-sections that follow.

3.4 Recommended Scenarios

The Commission has long required the IOUs to undertake analysis of various scenarios.[105] This continues in the current OIR where the Commission states "[it] could consider […] minimum and/or flexible requirements for scenario analysis."[106] In response to this direction, staff sought and received feedback from stakeholders regarding scenarios that IOUs should analyze for the 2010 LTPPs at an August 28, 2008 workshop on scenarios and metrics and through the course of two additional working group meetings. Stakeholders generally agreed that scenarios should be limited in number,[107] should generate useful and non-redundant information,[108] and should include sufficiently distinct parameters to encompass a range of possible futures and result in substantively different portfolios to analyze.[109]

Staff suggests that the IOUs, in consultation with the CPUC staff and stakeholders, develop a full set of scenarios to be investigated in the LTPP based on the most relevant set of resource questions and uncertainties at the time. Given that state policies,

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[105] See, for example, D.97249, 5 CPUC2d 620, 636.

[106] *R.08-02-007 OIR*, at p. A-7.

[107] See, for example, *Pre-Workshop Comments of the Green Power Institute on Planning Scenarios and Metrics*, served on August 22, 2008, at p. 1. Available at http://www.cpuc.ca.gov/NR/rdonlyres/88136D06-0001-4C50-8AA1-33654F34B39C/0/GPIPreWorkshopCommentsScenariosandMetrics.pdf

[108] See, for example, *Pre-Workshop Comments of the Natural Resources Defense Council and the Union of Concerned Scientists on Planning Scenarios and Metrics*, served on August 22, 2008, at p. 2. Available at http://www.cpuc.ca.gov/NR/rdonlyres/DF37D3F5-4CD0-4AE0-AD74-9B8C1EC10B79/0/UCSPreWorkshopCommentsScenariosandMetrics.pdf

[109] See, for example, *Southern California Edison's Pre-Workshop Comments re Scenarios and Metrics*, served August 22, 2008, at p. 1. Available at http://www.cpuc.ca.gov/NR/rdonlyres/0691BC3E-4F01-4C0E-B7D8-F8FD4BE165C0/0/SCEPreWorkshopCommentsScenariosandMetrics.pdf

especially those related to resource procurement choices, are developing and may change, it is difficult to select a final list of scenarios that should be considered in the 2010 LTPPs or beyond. Nevertheless, staff provides recommendations for a minimum set of required scenarios for the 2010 LTPPs, summarized in Table 2. Additional optional scenarios that could be added to the 2010 LTPP, and/or subsequent planning cycles, are provided in Table 3.

These recommendations were informed by parties' pre-workshop comments and discussions at the August 28, 2008 workshop. Environmental advocates asked for scenarios requiring higher levels of renewables (e.g., 40% RPS)[110] or deeper cuts in GHG emissions than required by AB32.[111] However, subsequent investigations in the 33% RPS Implementation Analysis suggested that these scenarios were either infeasible or implausible in the timeframes that will be represented in the 2010 LTPPs.[112] Other scenarios suggested by parties, such as to assess high levels of expanded use of CHP (i.e., 4000 MW),[113] were included because they align with CARB Scoping Plan "complementary polices" to reduce GHG emissions.

Other scenarios could be developed for the 2010 LTPP in addition to, or as replacements for the scenarios described below, which may better reflect the relevant policy questions at the time the LTPP is prepared. Each scenario should provide useful and distinct information to answer a timely and policy-relevant resource procurement question.

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[110] See, for example, *Comments of the Community Environmental Council on Scenarios and Metrics*, served August 22, 2008, at p. 3. Available at http://www.cpuc.ca.gov/NR/rdonlyres/B89C9C88-6892-4758-A1C1-FB22039BC984/0/CECouncilPreWorkshopCommentsScenariosandMetrics.pdf

[111] See, for example, *Response to Workshop Questions and Re-Submittal of Pre-Workshop Comments Regarding Scenarios and Metrics*, served August 22, 2008, at pp. B-2 – B-3. Available at http://www.cpuc.ca.gov/NR/rdonlyres/F5F876CB-1E34-4965-B79E-AA130EBB3569/0/CEERTPreWorkshopCommentsScenariosandMetrics.pdf

[112] See, for example, Timeline 2B in the *Preliminary 33% RPS Report*, at pp. 48-49.

[113] See, for example, *Comments of the California Large Energy Consumers Association and the California Manufacturers and Technology Association in Response to the Questions Posed in the August 11, 2008 CPUC Staff Notice of Workshop on Planning Scenarios and Metrics*, served August 22, 2008, at p. 1. Available at http://www.cpuc.ca.gov/NR/rdonlyres/A8D456EB-8850-48C2-91DA-177796F87104/0/CLECACMTAPreWorkshopCommentsScenariosandMetrics.pdf

Table 2: Recommendations for required scenarios for 2010 System Plans

Scenario	Description and Purpose of Portfolio
0. Natural gas only scenario	Build a portfolio that meets forecast demand with only new natural gas resources. This portfolio would provide a simple baseline against which other cases could be compared. This portfolio would be useful as a comparison point to calculate the effect of resource choices on total cost and GHG emissions. For example, the CARB baseline 2020 GHG emissions forecast is based on the assumption that all new electric resources are gas-fired. This portfolio would not comply with state mandates and is included only for benchmarking purposes for certain metrics.
1. CARB complementary policies scenario	This portfolio would reflect the likely cost, risk and environmental impacts of procuring the resources listed in the CARB Scoping Plan and pending rulemaking. While the state would make every effort to achieve the resource goals that CARB sets, the portfolios would be subjected to a Deliverability Risk Assessment such that the resource online dates might not match the CARB's specifications. Energy Division expects that renewable resources in this portfolio would largely represent resources that are bid into utility RPS RFOs.[114] The purpose of this scenario is to identify the cost and GHG impacts of a portfolio of resources that meets CARB's goals.
2. Least-cost renewables scenario (if different from CARB scenario)[115]	Current RPS rules require that RPS-eligible energy must be delivered to California. If not already represented in the CARB scenario, it would be useful to consider a portfolio in which cheaper in-state resources (e.g., wind), or out-of-state resources not delivered to California (i.e., purchase of RECs for some portion of its RPS need), or out-of-state delivered resources are emphasized, to the extent any of these strategies results in a lower-cost portfolio. In either case, the scenario should be compliant with RPS law. Other than modifications to the RPS portfolio, the scenario would be identical to the CARB scenario in all other respects.

[114] For example, the 33% RPS Implementation Analysis produced a reference case portfolio reflecting recent commercial activity that has shown a significant amount of solar technologies.

[115] For example, the 33% RPS Implementation Analysis found that a high (in-state) wind case and a high out-of-state delivered case were both lower cost than the reference case portfolio.

Scenario	Description and Purpose of Portfolio
3. Transmission-constrained scenario	This scenario anticipates that it will be difficult to site and construct new, high-voltage transmission lines to bring remote renewable resources to load. This portfolio would reflect the likely cost, risk and environmental impacts of relying principally on *distributed* renewable resources that do not require the construction of new long-line transmission, to meet the state's RPS and GHG reduction requirements. The scenario would be identical to the CARB scenario in all other respects.
4. OTC policy/Nuclear retirements	The SWRCB is promulgating rules to limit use of OTC technology in power plants, including nuclear plants. The IOUs should build a portfolio that meets reliability needs, assuming the retirement of all nuclear plants at expiration of NRC permits. The purpose of this scenario is to prepare for implementation of SWRCB's final rule. The scenario would be identical to the CARB scenario in all other respects.

Table 3: Additional optional scenarios for 2010 and subsequent Plans

Scenario	Description and Purpose of Portfolio
5. IOU-preferred scenario[116]	IOUs build a portfolio that represents their preferred resource mixes in the absence of state mandates, other than a requirement that the IOUs either reduce GHG emissions by a given amount or procure a like amount of CO_2 allowances to meet AB 32 requirements. The scenario must also include the current statutory requirement of a 20% RPS. This portfolio would allow a comparison of the impacts of regulatory flexibility in implementing AB 32 against the impacts of implementing current policy.

[116] The IOUs supported allowing them to specify and analyze their own preferred scenarios. Other parties (e.g., DRA) notably discouraged the Commission from allowing the IOUs to do so, unless scenarios are specified in advance, because results of the three IOUs' plans would be difficult to compare. See, for example, *Response of the Division of Ratepayer Advocates to the Notice of August 28, 2008 Energy Division Workshop on Planning Scenarios and Metrics Data Request*, served August 22, 2008, at p. 5 Available at http://www.cpuc.ca.gov/NR/rdonlyres/AAFAB705-9D7E-4420-9C4A-00F974B9A4C1/0/DRAPreWorkshopCommentsScenariosandMetrics.doc

Scenario	Description and Purpose of Portfolio
6. High vehicle electrification scenario	The CPUC convened an Electrification Working Group to examine whether it would be useful for the 2010 LTPPs to consider a scenario with substantial penetration of plug-in electric vehicles. The Working Group determined that the likely effect on loads from electrification was relatively small over the planning horizon for the 2010 LTPPs, so a required scenario was not recommended. However, it is listed here as a potentially interesting case for a future round of LTPP.
7. Very high gas and CO_2 price scenario	The Scenarios and Metrics Working Group discussed requiring a scenario in which natural gas and CO_2 allowance prices are allowed to rise to levels that would spur substantial additional penetration of renewables beyond the current 20% statutory requirement.
8. High in-state wind scenario	This scenario anticipates that large-scale solar resource development proves untenable or sufficiently costly that wind becomes the dominant renewable resource developed in California. This portfolio could be useful for testing the limits of the electricity system to integrate intermittent wind resources and providing an upper bound on the need for resources such as dispatchable gas-fired CTs or energy storage for wind integration.
9. IGCC or nuclear scenario	This scenario anticipates that future events enable the development of nuclear and/or coal fired, integrated gasification combined-cycle resources with carbon capture and sequestration, either in California or in neighboring states. These technologies represent alternatives to renewable resources for providing large quantities of low-carbon electricity. This portfolio would be useful for testing the effects of building new, non-renewable, low-carbon baseload energy technologies.
10. Market transformation scenario	This scenario anticipates that technology and market developments will result in substantial reductions in the cost of less mature renewable resources, particularly solar resources. This scenario would test whether the preferred resource portfolio would change dramatically given aggressive, but plausible assumptions for technology cost reductions. The scenario would be identical to the CARB scenario in all other respects.

3.5 Evaluation Criteria

The OIR suggests that "the Commission might consider prescribing certain types of output variables that candidate resource portfolios should be evaluated against."[117] Pursuant to this guidance, the evaluation criteria discussed in this sub-section are designed to evaluate the performance of each portfolio with respect to the Guiding Principles, Working Principles and Foundational Elements described in this report. These metrics and assessments will help to guide the selection of an appropriate resource mix for a given scenario, and to ensure that the goals of electric service provision are met. First, electric service must be reliable, and second it should reflect a "least cost, best fit" resource mix which balances the trade-offs between cost, risk and environmental impact, such that the utilities move further towards achieving state policy goals.

Quantitative criteria, which apply standard calculations, are referred to as "metrics." Qualitative criteria requiring subjective judgment are referred to as "assessments." The quantitative metrics and qualitative assessments discussed in this sub-section are recommended as a means of fulfilling the Commission's goal of allowing stakeholders "to better understand the economic, reliability, and environmental trade-offs between different resource choices – both across different types of supply- and demand-side "generation": and between generation and transmission."[118] For example, Commissioners concluded that, "Upfront standards for procurement must now consider carbon risk when filling net short positions with fossil resources…"[119] Thus, staff recommends including an expected cost of CO_2 in the cost metrics, discussed below, in addition to a separate calculation of total GHG emissions associated with each portfolio.

Many of these recommendations have benefited from input from stakeholders. On July 10th 2008, the Energy Division hosted a workshop on GHG Uncertainty, following stakeholders' submittal of pre-workshop comments, which discussed options for

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[117] *R.08-02-007 OIR*, at p. A-8.

[118] *R. 08-02-007 OIR*, at p. A-5.

[119] *R.08-02-007 OIR*, at p. 3.

incorporating GHG regulatory risk into the LTPP proceeding. Likewise, stakeholders provided written comments on planning scenarios and metrics in response to an August 28, 2008 Energy Division workshop on the topic. Two additional working group meetings were held September 2008 in which stakeholders discussed in more depth the question of what metrics should be applied to the LTPP portfolios. Stakeholders provided informal written feedback through assigned "homework" questions, including questions regarding options for environmental metrics.

Staff recommends inclusion of three categories of metrics: cost, risk and GHG emissions. In addition, staff recommends including three qualitative assessments of system-level resource portfolios: a high-level environmental assessment, a resource development timeline assessment, and a long-term GHG reduction and market transformation assessment. Staff believes that these qualitative assessments will better elucidate resource portfolio tradeoffs than the quantitative metrics alone could achieve. The recommended metrics proposed here are largely reflective of the conversations between Aspen/E3, Energy Division and stakeholders in September and October 2008. Stakeholders did not always agree on how to apply metrics to the LTPP proceeding – these recommendation seek to strike a balance between differing viewpoints. For example, environmental advocates (e.g., GPI, NRDC/UCS) suggested "economic stimulus" benefits as an additional metric.[120] However, evaluating macroeconomic effects of alternative resource plans is both resource-intensive and peripheral to the Commission's mandate of "protecting consumers and ensuring the provision of safe, reliable utility service and infrastructure at reasonable rates"; hence, staff does not recommend mandatory inclusion of a macroeconomic metric.

3.5.1 Metrics and Assessments for System Plans

This sub-section describes a recommended set of quantitative and qualitative criteria which the IOUs should use to evaluate portfolios in the System Plans. The metrics recommended for the Bundled Plan are described separately (in Section 3.5.2).

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[120] See *Pre-Workshop Comments of the Green Power Institute on Planning Scenarios and Metrics*, served on August 22, 2008, at p. 3. Also, see *Pre-Workshop Comments of the Natural Resources Defense Council and the Union of Concerned Scientists on Planning Scenarios and Metrics*, served on August 22, 2008, at p. 8.

Before describing metrics and assessments, it is important to clarify how staff proposes to treat reliability levels.

Reliability

Recommendation: *Reliability should be treated as an input constraint, rather than as a separate evaluation metric.*

Maintaining reliable electric service is the paramount goal of utility planning. At the CPUC, reliability concerns are largely addressed through a combination of the RA proceedings (R.05-12-013, R.08-01-025, and any successors) and the Planning Reserve Margin (PRM) proceeding (R.08-04-012). Currently, the adopted PRM is 15-17% of peak demand. In developing the planning reserve, the PRM proceeding takes into account variability in load due to weather and economic and demographic conditions. Although working group members disagreed on this point, staff recommends that the importance of reliability as an evaluation criterion be reduced or eliminated from the LTPP to avoid duplication of the PRM proceeding work.[121] In the LTPP, each resource portfolio should include sufficient levels of appropriate resources in order the PRM requirement. While utilities may also choose to calculate and report a reliability metric (e.g. loss of load probability), or qualitatively assess the reliability benefits of a given portfolio above the PRM, staff would discourage assessment of reliability benefits outside the PRM proceeding.

The recommended System Plan metrics and assessments are summarized in Table 4 below and then described in more detail in the text that follows.

Table 4: Recommended metrics and assessments for System Plans

Metrics	Description
1. Cost	a) Net Present Value Revenue Requirement (utility cost)
	b) Total Resource Cost (customer cost and utility cost)

[121] This recommendation was supported by SCE (see August 22, 2008 pre-workshop comments, at pp. 4-5), SDG&E (see same, at p. 10), and CLECA/CFTMA (see same, at p. 2). It was opposed by PG&E (see same, at p. 7) and CAC/EPUC (see same, at p. 4).

2. Risk	Robust scenario and sensitivity analysis
3. GHG Emissions	a) Total GHG emissions during each year of the planning horizon b) Average, per ton cost of GHG emissions abatement
Assessments	**Description**
4. Environmental	Environmental impacts of resource portfolios such as air emissions, land and water use requirements, and impacts on species
5. Resource development timeline	Expected timelines to achieve resource build-outs based on permitting and siting requirements, project development risk and other project development requirements
6. Long-term GHG reductions and technology transformation	Qualitative assessment of trajectory of GHG emissions towards 2050 goals, including assessment of potential for resource portfolios to drive long-term technology transformation to achieve GHG reductions

1. Cost Metrics

Recommendation: *Portfolios should be evaluated on the basis of at least two cost metrics: the net present value of the utility revenue requirement ("PVRR") to capture the effect on ratepayers, and a "total resource cost" metric ("TRC") to capture a more complete economic measure of costs to California energy consumers.*

Staff recommends calculating both the PVRR and the TRC metrics in the 2010 LTPPs because each metric captures a different cost perspective of a portfolio. Cost metrics should include the impact of a forecast of CO_2 allowance costs that reflects current policies regarding the allocation of CO_2 emissions allowances under a GHG emissions regulatory regime.

Present Value of Utility Revenue Requirement

PVRR is a standard metric that most utilities compute as part of their resource planning analysis. The PVRR includes all costs required to meet system demand that are expected to enter into utility and/or electric service provider rates. The PVRR includes generation costs as well as transmission, distribution, and all other utility costs. PVRR thus measures the overall cost impact of a given portfolio on all, system-wide ratepayers. The PVRR does not seek to capture the distributional impacts that result from specific electric service provider rate structures and demand. To calculate PVRR, the total, system-wide revenue requirements are summed for each year of the planning horizon, and then discounted back to base year dollars using an appropriate discount rate.

A forecast of CO_2 allowance costs should be included in the PVRR calculation. As discussed in Section 3.8.3 of this report, staff recommends using the CO_2 price forecast methodology included in the most recent MPR. The Commission will also need to define the policy assumptions to use when calculating the effect of CO_2 prices on generation costs and costs to utilities. CO_2 costs should be assessed based on reasonable assumptions about the future direction of GHG reduction policies, or based on actual policy, to the extent that such policies have been finalized. Whatever assumptions are made regarding the impact of CO_2 prices on generation costs and utility costs, these assumptions should be transparent and clear in the presentation of the final results.

Total Resource Cost[122]

While PVRR is a good measure of the cost impact of providing electric service to ratepayers, it may not present an accurate picture of the total ratepayer costs associated with a given portfolio, especially if the portfolio relies on program participants to fund a large portion of the necessary investments. Many of California's policy goals are aimed at increasing the deployment of distributed energy resources such as EE, DR and rooftop solar, resources that require substantial customer contributions in addition to utility support. Staff therefore recommends that the PVRR metric would be usefully supplemented with a TRC metric. The TRC metric includes both utility and customer contributions toward the resource cost, but excludes any incentives that the utility pays to the customer. It is not necessary to calculate customer and utility costs for programs that are administered outside of the utility sector, such as building codes and standards. Customer and utility costs should be calculated for all utility-sector programs administered by the Commission and the CEC, including EE, DR, CSI, CHP, and others.

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[122] This is a generic metric of the utility resource portfolio, not to be confused with the specific use of the same term in the context of cost-effectiveness determinations of individual EE programs or EE portfolios.

Term of the Cost Calculations

While the LTPPs are designed to inform resource decisions made during the first 10 years of the planning horizon, the resources that are procured continue to produce energy long after the 10 year period. Because fossil fuel and CO_2 allowance prices may continue to rise after the end of the 10-year period, staff recommends that cost metrics be calculated over at least 20 years. If a 20-year time period is selected, there should be an additional component to the analysis that captures "end effects" after the end of the 20-year period. Staff recommends using a "salvage value" approach that credits ratepayers with the remaining market value of the resource, given appropriate scenario and sensitivity assumptions for CO_2 price and natural gas price forecasts. This approach is consistent with a methodology jointly submitted by the three IOUs during the working group process.

2. Risk Metrics

Recommendation: *The IOUs should conduct robust scenario and sensitivity analyses be conducted to assess a variety of risks associated with a given set of resource portfolios. Proposed scenarios and sensitivities are discussed in more detail in Sections 3.4 and 3.6, respectively.*

Ratepayer risk is defined as the exposure of ratepayers to unexpected changes in commodity prices that affect the price of electricity. Natural gas prices are difficult to forecast, and natural gas price fluctuations have long exposed ratepayers in California to electricity price uncertainty. Currently, there is also a great deal of uncertainty surrounding the future of CO_2 prices and how GHG emissions policies will affect electricity rates. Given that both natural gas prices and CO_2 prices are highly uncertain, and forecasts of both are ill informed by considerations of historical data, these price risks can best be assessed through robust sensitivity analysis.

The *Best Practices Report* revealed that, while all utilities use sensitivity and scenario analyses to assess risk, only about half of those surveyed also use a stochastic risk metric, such as TEVaR (To-Expiration Value-at-Risk) or TailVaR (Tail Value-at-Risk). Follow-up conversations revealed that even among those utilities that use TEVaR or TailVar there is recognition of the limits and challenges of using a stochastic risk metric to measure portfolio risk over a long planning horizon. In particular, planners recognize that statistical relationships among key variables that are derived during a given historical period become increasingly dubious as more time elapses between the historical period and the planning period. While there was no uniformity among the analysts that Aspen/E3 interviewed regarding the time period in which these statistical relationships can be considered valid, most agreed that the accuracy of stochastic risk metrics beyond five years is questionable. These findings are consistent with the 2007 IEPR, which examined the usefulness of the TEVaR metric. The report found that while TEVaR was an appropriate risk management tool for short term fluctuations in market power and natural gas costs, it was not appropriate for a long-term quantification of risk.[123]

In the 2006 LTPP, the IOUs did not employ a risk metric to their System Plans; however, their Bundled Plans did contain measures of market price risk using TEVaR or other stochastic methods.[124] For the five-to-ten year forward time period of the System Plans, the advantages of stochastic analysis do not appear to strongly outweigh the potential costs of conducting the analysis; thus, staff does not recommend that the Commission require the use of stochastic analysis in the System Plans. To be clear, this recommendation is unrelated to the Commission's TEVaR policy for bundled portfolio management. Rather, staff recommends that the LTPP System Plan filing should contain a rigorous analysis of different resource portfolio options supported by a robust sensitivity analysis. The proposed sensitivity analysis variables are described in Section 3.6.

However, a stochastic risk metric does have some advantages. A stochastic measure simultaneously evaluates changes in multiple variables, taking into consideration their correlation (if known), and condenses these multiple effects into a single metric. For the same reason, a stochastic risk metric may also be considered subject to less interpretation bias, as it allows direct comparison of portfolios on a single metric. A stochastic variable

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[123] CEC (2007). *Portfolio Analysis and its Potential Application to Utility Long-term Planning*, Final Staff Report, CEC-200-2007-012-SF, August 2007. See Appendix 1.

[124] See *Best Practices Report: Appendix B*, at pp. 116-118 (for PG&E), at p. 124 (for SCE), at p. 126 (for SDG&E)

may be particularly valuable in evaluating portfolios with a high dependence on hydroelectric resources, the output of which fluctuates from year to year. Finally, a number of analysts noted that, while the statistical relationships that underlie stochastic analysis may not be formally rigorous, the analysis should still provide results that are "directionally correct"; that is, it should result in an accurate ranking of multiple portfolios. Hence, staff recommends that the Commission leave to the IOUs the choice of whether to apply a stochastic risk analysis in their Portfolio Analysis.

3. Greenhouse Gas Emissions Metrics

Recommendation: *The LTPP filings should report the total GHG emissions associated with each portfolio during each year of the planning horizon.*

Recommendation: *The LTPP filings should calculate the average, per ton cost of CO_2 emissions reductions for each portfolio, relative to a baseline portfolio (defined as an "all-gas" scenario for the 2010 LTPP).*

In the Scoping Memo, the Commission clearly indicated that the proceeding was to consider, "interim standards and practices to evaluate the uncertain cost of future GHG regulations during AB 32 implementation and in anticipation of possible federal legislation".[125] Staff recommends that GHG regulatory uncertainty, and future GHG regulations, be fully integrated into the LTPP analysis, as follows. First, a forecast of net GHG costs to ratepayers should be included in the PVRR cost metric, discussed above. Second, GHG costs should be included in the sensitivity analysis, discussed in Section 3.6. Finally, GHG emissions should be calculated and reported as an important environmental metric. GHG emissions should be calculated for each year of the planning horizon, and GHG emissions for target years such as 2020 should be reported as a formal metric.

Staff also recommends calculating the average, per-ton cost of CO_2 emissions abatement relative to a baseline portfolio. For the 2010 LTPPs, the baseline portfolio would represent an "all-gas" portfolio. To calculate the average cost of CO_2 emissions reduction, the change in PVRR relative to the baseline portfolio cost is divided by the

[125] *R.08-02-007 OIR*, at p. 10.

change in total GHG emissions relative to the baseline portfolio. This metric should be calculated for each year of the forecast period, and discounted to present day values using an appropriate discount rate. This is a useful portfolio evaluation criterion because it provides an indication of a portfolio's cost-effectiveness in reducing GHG emissions. A portfolio that results in the same GHG emissions as an alternative portfolio, but at a lower average cost per ton of avoided CO_2 could be considered more cost-effective at reducing GHG emissions. This information may be used by the Commission to evaluate the relative impacts of different resource choices on GHG emissions and cost.

4. Environmental Assessment

Recommendation: *The LTPP filings should include a qualitative assessment of the environmental impacts of each resource portfolio, which may include land use impacts, water use impacts, impacts on species, or other local and or regional environmental impacts.*

IOUs should qualitatively evaluate resource portfolios based on an estimate of the environmental impacts of the resources. This could include an assessment of the impact on local air quality in sensitive areas, land use impacts such as transmission rights of way and land use requirements for new resource development, or other cumulative environmental impacts such as impacts to species. The goal of this environmental assessment would be to qualitatively assess the cumulative, high-level environmental impacts associated with a given portfolio. This assessment would not replace the more rigorous environmental review undertaken as part of CEQA, because it would consider only general environmental impacts associated with resource types or renewable energy zones, rather than the project-specific impacts that are analyzed in detail under CEQA.

5. Resource Development Timeline Assessment

Recommendation: *The LTPP filings should include a detailed schedule of on-line dates for conventional and renewable resources, demand-side achievements and transmission facilities.*

Providing reliable service requires having enough resources online to meet customer loads during each hour of each year. The LTPP filings should include a detailed timeline of online dates for renewable and conventional generation resources, transmission facilities, and achievement of demand-side goals. The timeline is a critical piece of the System Plan, because the timing of resource online dates drives the need for supplemental resources to ensure system reliability.

The timeline should be based on the best available information about the timelines for planning, financing, permitting and constructing new generation and transmission facilities as well as detailed information about projected demand-side achievements such as EE, DR, CSI, CHP and others. The System Plan should make use of information from other Commission proceedings to the maximum extent possible in order to avoid duplication of effort. However, the System Plan should not simply take ambitious policy goals at face value. Rather, the System Plan should take a realistic view of the *most likely* achievements and plan supplemental resources based on this realistic assessment in order to ensure system reliability.

6. Long-term GHG and Technology Transformation Assessment

Recommendation: *The LTPP filings should include a qualitative assessment of the impacts of each portfolio on the ability of the state to meet long-term GHG reduction goals of 80 percent below 1990 levels by 2050 and the potential impact of portfolio resource choices to influence long-term technology transformation.*

The Global Warming Solutions Act of 2006 (AB 32) calls for California to reduce its GHG emissions to 1990 levels by 2020. However, near-term GHG emissions reductions will not be meaningful unless they are accompanied by more aggressive cuts in the long term. Scientists estimate that reductions of 50-80% below 1990 levels are necessary by 2050 to stabilize the global climate[126], and Governor Schwarzenegger has set a goal of 80% reductions below 1990 levels by 2050.[127]

In the working group process, NRDC/UCS jointly provided suggestions for how the IOUs could usefully incorporate a long-term (beyond-2030) GHG emissions forecast in

[126] Intergovernmental Panel on Climate Change, "Fourth Assessment Report: Climate Change 2007 Synthesis Report," 2007.

[127] Governor Schwarzenegger Executive Order S-3-05, June 1, 2006.

their LTPP Portfolio Analysis. The NRDC/UCS joint proposal focuses on estimating the long-term GHG implications of resource procurement choices made over the next twenty years. The GHG emissions of these resources would then be extended to 2050 based on assumptions about the remaining useful lifetime of the resources. Stakeholders responded to these proposals, highlighting many of the uncertainties associated with undertaking any sort of long-term forecast of this sort.

Staff recommends that, while the LTPP proceeding is necessarily focused on utility actions in the relatively near term, i.e., over a 10-year time horizon, the plan should not lose sight of the long-term GHG goals. For example, focusing exclusively on minimizing ratepayer cost in the near term may result in a resource portfolio that achieves incremental GHG reductions at relatively low cost, but does little to bring about the kinds of long-term market transformations that are necessary for deep GHG reductions.

The LTPP filings should qualitatively evaluate the potential of each resource portfolio to result in long-term technology transformations. Portfolios that rely heavily on existing, mature technologies would score poorly under this criterion, while portfolios that include emerging technologies with long-term potential for substantial cost reductions would score highly. This will allow the IOUs and the Commission to explicitly evaluate the tradeoff between short-term costs and long-term transformational benefits when selecting a preferred resource portfolio.

3.5.2 Metrics for Bundled Plans

The bundled load portion of the LTPP analysis does not require the same depth of quantitative and qualitative assessment as the system analysis. This is because many of the attributes of the System Plan will also apply to the Bundled Plan, and it is not necessary to perform the same assessment of both. In addition, a major focus of the System Plan is evaluating the effects of state policy requirements and the infrastructure that is necessary to implement them. The purpose of the Bundled Plan, by contrast, is to provide the IOUs with authorization to procure energy supplies to meet the residual energy needs of bundled ratepayers and to assess the cost and risk of alternative resource portfolios to those ratepayers. However, given that the possible resource portfolios are likely to be heavily constrained by policy mandates, staff believes the Bundled Plan analysis can be simplified. Thus, staff recommends that the Bundled Plan calculate cost, risk and GHG emissions metrics for each portfolio. These three metrics are described below in Table 5.

Table 5: Recommended metrics for Bundled Plans

Metrics	Description
1. Cost	Net Present Value Revenue Requirement (utility cost)
2. Risk	TEVaR and robust sensitivity analysis
3. GHG Emissions	Total GHG emissions in starting year and 10 years out

1. Cost

Recommendation: *Portfolios should be evaluated on the basis of the net present value revenue requirement.*

This metric will be calculated the same way as in the system analysis, this time using only bundled load resources. A TRC metric is not needed for the Bundled Plan since issues related to demand-side portfolios are addressed in the System Plan.

2. Risk

Recommendation: *IOUs should conduct robust sensitivity analysis to test the ratepayer risk associated with each portfolio.*

This report recommends that analysis of alternative policy and technology scenarios be conducted as part of the System Plan. Thus, there should be no need to duplicate such analysis for the Bundled Plan. Rather, the Bundled Plan should focus on measuring the sensitivity of each candidate portfolio to changes in key cost parameters such as natural gas and CO_2 allowance prices. In addition, the IOUs should continue as they have in past LTPPs to calculate formal risk metrics such as TeVAR, as part of the Bundled Plan.

3. Greenhouse Gas Emissions

Recommendation: *IOUs should calculate the GHG emissions associated with serving their bundled load during each year of the planning horizon.*

Staff expects the bulk of the analysis of different GHG regulatory regimes and alternative strategies for reducing GHG emissions to be conducted as part of the System Plan. Thus, consideration of GHGs in the Bundled Plan need not go beyond measuring the total GHG emissions of a given portfolio under a given scenario and its impact on bundled ratepayers.

3.6 Recommended Sensitivity Analyses for System Plans and Bundled Plans

Creating a resource plan necessarily involves projections about the future state of the world over the planning horizon. Key drivers of portfolio cost – resource need, fuel prices, carbon prices, technology costs – cannot be forecast with certainty. Sensitivity analysis tests the effect of changes in these key variables on the total cost of a given portfolio. In this way, sensitivity analysis, in combination with scenario analysis, helps to gauge the risk of developing a given portfolio if key assumptions turn out to be different than expected.

In conducting sensitivity analysis, a balance must be sought between thoroughness of the investigation and ease of interpreting the results. If too few variables are tested, important information may be omitted from the results; if an excessive number of variables are tested, it may be more difficult to interpret and derive meaningful conclusions from the results. Staff recommends testing each portfolio's cost estimates against a limited and useful set of variables. The sensitivity analysis would not require recreating portfolios and may not require new production simulation model runs. Rather, the IOUs could assume that the resource portfolio and dispatch would not change under the sensitivity. Thus, the sensitivity would simply apply different prices to a fixed schedule of PPA (or capital) expenditures, fuel consumption, and market purchases.

Staff provides the following recommendations for required sensitivity analysis for the 2010 Plans. The recommendations in Table 6 apply to both the System and the Bundled Plans, unless otherwise specified.

Table 6: Recommendations for required sensitivity analysis

Sensitivity	Purpose
1. Natural Gas Prices	A high and a low natural gas price should be tested at feasible extremes. Increases in the price of natural gas will affect the competitiveness of renewable resources by increasing the cost of fossil resources and decreasing the relative cost impact of achieving high renewables penetration.
2. CO_2 Prices	A high and a low CO_2 price should be tested at feasible extremes. Increases in the price of CO_2 will affect the competitiveness of renewable resources by increasing the cost of fossil resources and decreasing the relative cost impact of achieving high renewables penetration. High CO_2 prices might also spur the early retirement or replacement of existing coal-fired resources.
3. Need Level	Both the System and Bundled Plans should include "High-Need" and "Low-Need" sensitivities, corresponding to the uncertainty bands required around net short calculations, as described in Section 3.8.1. For the System Plan, the "Low-Need" sensitivity should reflect more optimistic assumptions about policy-driven resource achievements (e.g., EE, DR, customer-side DG, and CHP) in order to provide information into other Commission proceedings about the cost savings associated with incremental changes in load level. The "High-Need" sensitivity should reflect extremes in load due to weather, economic, and demographic conditions beyond what is already accounted for in the PRM; as well as, more conservative assumptions about policy-driven resource achievements. For the Bundled Plan, the sensitivities should reflect ratepayer risk associated with lower load or higher levels of DA/CCA.

Sensitivity	Purpose
4. Technology Cost (System Plan only)	As discussed above, many believe that technology and market developments will result in substantial reductions in the cost of less mature renewable resources, particularly solar resources. Reductions could also occur in the cost of nuclear and/or IGCC resources. This sensitivity would test the effect on a portfolio's cost if there were a substantial drop over time in the cost of a selective set of resources. Particularly in conjunction with the (optional) Market Transformation Scenario described above, this sensitivity tests the risk to ratepayers of stranded costs associated with a portfolio that is heavy in resources that do *not* undergo market transformation.

1. & 2. Natural Gas and CO_2 Price Sensitivity

The natural gas and CO_2 price sensitivity analysis should test a wide range of price levels. There was discussion in the Scenarios and Metrics Working Group about whether or not the IOUs should adopt a "corner point" approach for selecting appropriate sensitivity values. Under this approach, the IOUs would test increasingly extreme values until a significant change occurred in the preferred portfolio. This process would provide interesting information about how robust the preferred portfolio is – if the preferred portfolio changes with relatively minor changes in gas and/or CO_2 prices, this is an indication that the preferred portfolio is highly sensitive to changes in these key inputs, and that the IOUs and the Commission should strongly consider the circumstances in which a different portfolio would be preferred. If, on the other hand, the preferred portfolio does not change even under extreme changes in gas and/or CO_2 prices, this is an indication that the portfolio is robust with respect to these variables. If the portfolios were tested only under mild values, the analysis would not provide this information. While not conclusively stating that a "corner point" approach is desirable, staff does recommend that the IOUs test the sensitivity to a wide range of price levels, including some extreme values.

There was also discussion in the July 10, 2008 workshop on GHG uncertainty and in pre-workshop comments submitted by parties about whether it is possible to predict a correlation between future natural gas prices and CO_2 prices. Some parties argue that stringent GHG regulation will lead to *lower* natural gas prices, as increased penetration of renewable resources reduces electricity sector gas demand. Others argue that GHG regulation will lead to *higher* natural gas prices, as demand for coal and oil is displaced by less-carbon-intensive natural gas. Staff finds that, at this early stage in the development of GHG regulations and policies, it is not possible to determine whether CO_2 prices and natural gas prices would show a positive or negative correlation.

3. Need Sensitivity

In D.07-12-052, the Commission "based findings…of need on the CEC's base case 1-in-2 summer temperature demand forecast."[128] The current 15%-17% PRM accounts for a certain amount of unexpected variation in load due to economic, weather (e.g., 1-in-5 or more extreme events) and demographic conditions, as well as other contingencies, to ensure sufficient reliability given these uncertainties. The PRM is currently being reexamined in R.08-04-012, which anticipates methodology based on probabilistic analysis to explicitly quantify these sources of load variability, and update the PRM based on specified reliability levels. Pending a decision in R.08-04-012, the IOUs System Plans should include a "High-Need" sensitivity to quantify the effects of load variability beyond what is already accounted for in the PRM, including extremes in weather, economic and demographic variables and more conservative estimates of policy-driven resource achievements. As described further in Section 3.8.1, the utilities should estimate of the probability of occurrence of the "High-Need" sensitivity and present a rationale justifying the estimate.

With regard to demand-side resources, load impact forecasts are uncertain due to technological changes and/or regulatory policy changes. For example, the Commission expects that the utilities will continue to improve the existing DR programs and/or develop new DR programs to achieve the AMI-enabled DR potential.[129] With these

[128] D.07-12-052, FOF #13, at p. 272.

[129] In SCE AMI decision (D.08-09-039) and PG&E's AMI Upgrade decision (D.09-03-026), the Commission required both utilities to submit an annual report comparing the actual AMI-related DR load reduction to what they included in their AMI business cases.

actions DR load impacts forecasts would be greater than the base case assumptions. Further, once AB 1X expires, the Commission may adopt dynamic pricing for residential customers. The same possibility for higher-than-expected resource achievements exists for EE, customer-side DG, and CHP, which could see changes in policy or market conditions. Sensitivity analysis is an effective tool to address these uncertainties.

Therefore, for the System Plan, staff recommends that the utilities should run a "Low-Need" sensitivity case that incorporates higher-than-expected impacts policy-driven resources including EE, DR, small-scale customer-side DG (i.e., CSI), large-scale customer side DG (i.e., CHP), etc. For EE, the case should be developed based on the IEPR's high-case uncommitted EE forecast, as referenced in Section 3.8.1. For DR, the case should be developed using assumptions about innovative DR programs enhanced by MRTU integration, Smart Grid, and energy storage technologies, as well as other DR potential studies. The utilities should use assumptions for customer participation and elasticity based on methodologies consistent with Commission decisions on their AMI business cases (D.08-09-039, D.09-03-026, et al.). For other resources (e.g., customer-side DG, CHP) the IOUs should propose a consistent methodology to estimate impacts of "stretch" goals for these resources. As described further in Section 3.8.1, the utilities should estimate of the probability of occurrence of the "Low-Need" sensitivity and present a rationale justifying the estimate.

For the Bundled Plan, the need sensitivities should reflect ratepayer risk associated with lower load or higher levels of DA/CCA.

4. Technology Cost Sensitivity

Because the Bundled Plan would not address physical system issues such as the preferred mix of renewable resources to maintain reliable system operations or policy issues, such as whether the IOUs should invest ratepayer dollars in emerging technologies to foster long-term GHG reductions, staff believes that it is unnecessary for the Bundled Plan to include a sensitivity case on technology costs. Hence, staff recommends this sensitivity for the System Plan only.

3.7 Standardized Load and Resource Tables

During the spring of 2008, the IOUs, working together with the Energy Division staff, developed standardized tables for reporting loads and resources in the LTPP proceeding. These tables are reproduced as Tables Table 15Table 16Table 17 in Appendices C and D. Staff concurs with the IOUs' recommendation to present load and resource information in this format.

3.8 Inputs and Assumptions

This sub-section presents the staff's recommendations for sources of data for Inputs and Assumptions to the 2010 LTPPs. These recommendations were informed by the May 14, 2008 *Joint-IOU Report*, as well as subsequent meetings and comments. The *Joint-IOU Report* was the result of work accomplished in Planning Standards Working Group meetings which included the three IOUs, Energy Division and the CEC. The Pre-workshop Report included a number of recommendations regarding standardized assumptions which should be applied by the IOUs in the 2010 LTPPs. Subsequent working group meetings were held in September/October 2008 with broader participation from stakeholders, where many of the planning assumptions for the LTPP were discussed in more depth.

In general, the recommended inputs and assumptions discussed below are "Base Case" assumptions. Suggested variations on these reference case assumptions are discussed in the Scenarios and Sensitivity sections, (Sections 3.4 and 3.6) and are summarized below in Table 12 in Section 3.8.5. Assumptions are organized in four categories:

1. Calculating (system and bundled) net short position;
2. New resource cost and performance assumptions;
3. Market price forecasts; and
4. Accompanying studies.

3.8.1 Calculating Net Short Position

This category includes base case inputs and assumptions related to load, achievement of policy-driven demand-side resources such as EE and DR, and the disposition of existing resources. A requirement to estimate uncertainty bands around the net short calculation is also included. Table 7 below summarizes the key parameters, which would apply to both system and bundled assessments, unless otherwise noted.

Table 7: Recommendations for LTPP inputs and assumptions: Calculating net short position

Category	**Source for Base Case Assumptions**
1. Load growth	IEPR base case load forecast
2. Energy efficiency (EE)	IEPR forecast of embedded and uncommitted EE including Commission goals and Commission interpretation of CARB goals,[130] subject to Deliverability Risk Assessment
3. Demand response (DR)	IOUs propose a consistent methodology for estimating DR achievements in their service areas pursuant to the guidelines spelled out in this proposal
4. Combined heat and power (CHP)	Commission interpretation of CARB goals, subject to Deliverability Risk Assessment
5. Customer-side DG, including California Solar Initiative (CSI)	For the 2010 LTPPs, use IEPR estimates of embedded self-generation, including CSI, SGIP, small CHP, etc.; for subsequent LTPPs, Commission interpretation of CARB goals, subject to Deliverability Risk Assessment
6. Resource additions and retirements	IOUs propose consistent methodology for resource additions and retirements in their service areas (see *Joint-IOU Report*), reflecting OTC policy adopted by the SWRCB.
7. Re-contracting rates (Bundled Plan only)	IOU-specific

[130] See D.08-10-037 OP 1, at p. 256: "We recommend that [CARB] set [EE]requirements in its Scoping Plan at the level of all cost-effective [EE], with [EE] goals for [IOUs] set based on those adopted by the [CPUC] in D.08-07-047, and as may be revised and updated by the Public Utilities Commission from time to time."

1. Load Growth

Pursuant to D.07-12-052, the IOUs have been directed to use energy and peak demand forecasts based on the forecast developed for the CEC's 2009 IEPR and subsequent reports. The CEC forecast is publicly available and is disaggregated by load serving entity and service territory. The CEC's forecast is developed as part of the public IEPR process, so the assumptions underlying the forecast are thoroughly vetted. The CEC forecast is also developed using consistent assumptions across the IOUs service territories, which will allow for consistent comparisons between IOU LTPP filings.

As part of the 2009 IEPR, the CEC is working to develop a more complete disaggregation of the underlying load forecast from the EE and other behind-the-meter resources such as solar PV, CHP and other DG that may be embedded in the forecast. These assumptions should be explicitly taken into account by the IOUs as they develop their portfolios, ensuring that behind-the-meter resources are not "double-counted." This means that only the EE and other behind-the-meter resources that are incremental to the load forecast should be subtracted from the IEPR load forecast when calculating the net short position.

2. Energy Efficiency

Scenarios investigated in the LTPP should reflect the Commission-adopted EE savings goals for 2009 – 2011, and interim savings goals for 2012 – 2020 as described in D 08-07-047 under R.06-04-010, unless superseded by a subsequent CPUC decision. All EE savings the utilities expect to attain (to be not less than the Commission-adopted EE savings goals) should be decremented from the CEC load forecast in a manner that recognizes the amount of EE that the CEC determines is already embedded (so-called "committed") in the forecast, to avoid double-counting the savings.

Decision 08-07-047, which set the current EE goals, state that, "energy utilities shall use one hundred percent of the interim Total Market Gross [TMG] energy savings goals for 2012 through 2020 in future [LTPP] proceedings, until superseded by permanent goals."[131] However, the Commission has deferred to the CEC's IEPR process to generate load forecasting information necessary to interpret the impacts of TMG energy savings goals on procurement. Specifically, CEC and Commission staffs are collaborating in the 2009 IEPR proceeding to develop forecasts of "uncommitted" EE (i.e., TMG energy savings <u>not</u> embedded in the forecast.) Joint Staff, with input from parties, will apply the CEC's "reasonably expected to occur"[132] standard (a form of Deliverability Risk Assessment), as well as other information, to produce these forecasts. The CEC has agreed to produce at least two uncommitted EE forecasts, corresponding to the mid- and high-case EE scenarios in the Itron Goals Update Study filed in R.06-04-010, which will be available for use in the 2010 LTPP.

Should the 2009 IEPR process produce final uncommitted EE forecasts representing TMG energy savings impacts that vary from the Commission-adopted EE goals, staff recommends using the <u>lower of the two</u> quantities for purposes of calculating net short position, in the 2010 LTPP. Staff recommends this in order to ensure, with a high degree of confidence, that sufficient resources are available. Because this conservative approach introduces the possibility of unnecessary resource procurement (and cost), in subsequent LTPP cycles, staff recommends the IOUs propose a Deliverability Risk Assessment methodology using probabilistic tools (e.g., confidence intervals) around quantitative estimates of delivered EE impacts, so that the Commission can judge an acceptable level of deliverability risk. Until these more sophisticated techniques become available, it is reasonable to take a conservative approach when estimating delivered EE impacts in order to avoid adverse resource supply conditions that could potentially result in phased load shedding or rotating blackouts. At worst, a conservative choice from among two uncertain quantities would result in earlier procurement of resources than would otherwise be the case (even if this insurance comes as a cost). Also, the two-year

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[131] D.08-07-047, OP 3, at p. 39.

[132] Pursuant to the Warren-Alquist Act, CEC is statutorily required to incorporate conservation and energy efficiency that is "reasonably expected to occur" in its energy demand forecasts. Since 1985, reasonably expected to occur conservation programs have been split into two types: committed and uncommitted, While conservation reasonably expected to occur includes both committed and uncommitted programs, only the effects of committed programs are included in the load forecast. See CEC. (2009). *California Energy Demand Forecast 2010-2020 Staff Draft Forecast*, CEC-200-2009-012-SD, at p. 23.

planning cycle for the LTPP analyses allows for continual correction and/or refinement of estimates in order to correct for any over- or under-estimation based on actual accomplishments or new information.

Further, as described in D.08-07-047, IOU program EE savings and cost assumptions should be further developed by Commission staff, including utility cost and total cost assumptions for IOU Programs, Codes and Standards, AB 1109 (Huffman Bill) legislation, and the Big and Bold Energy Efficiency Strategies. When available, this information should be integrated into the LTPP analysis.

3. Demand Response

Base case assumptions about DR should reflect current DR program 2009-2011 plans (A.08-06-001,et. al.), DR programs approved through other Commission proceedings, and reasonably anticipated DR programs/resources such as those enabled by the IOU's AMI systems (including forecasted MW and budgets).[133]

The utilities should include the ex-ante annual load impact forecast (for 2011-2020) of 2009-2011 DR programs in four general categories: (1) emergency, (2) price responsive, (3) aggregator managed, and (4) permanent/seasonal load shifting, as specified in Table 17 in Appendix E. The forecast should also include AMI-enabled DR, such as price-responsive programs adopted or directed by the Commission, but yet to be implemented in the current (2009-2011) DR cycle, [134] and default and optional dynamic rates expected in 2011.[135] Finally, DR forecasts should include other DR programs approved by the Commission in pending decisions, such as SDG&E's aggregator contract application (A.09-03-012) and PG&E's aggregator DR contract modification application.

In accordance with D.08-04-050, the IOUs should "use the adopted protocols [in R.07-01-041] to estimate [Demand Response] DR load impacts for long-term procurement

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[133] In their AMI business cases, the IOUs claimed a large percentage of AMI benefits derived from enabling DR and conservation programs. Therefore, it is important to ensure that these expected benefits are captured and considered in the 2010 LTPP and future planning cycles, otherwise these benefits may never materialize through reduced procurement activity.

[134] These include, for example, PG&E's Peak Time Rebate (PTR).

[135] See timetable in D.08-07-045, Attachment B.

planning and resource adequacy purposes, unless otherwise directed…"[136] To the extent practicable, the utilities should follow the guidelines that are being developed by Energy Division staff in the 2010 RA proceeding for applying Load Impact Protocol ("LIP") information to the calculation of NQC. Staff recommends that the utilities, in consultation with Energy Division staff, submit an outline and a template for the 2011-2020 DR inputs to Energy Division 45 days prior to commencing modeling analyses in the 2010 LTPP.

IOUs should make their own assumptions about the cost of demand reductions achieved from DR programs, based on the performance of their current and planned DR programs. While D.08-04-050 provides guidance to the IOUs regarding load impacts from DR, the decision does not provide guidance as to how much IOUs are likely to spend on these programs over the next twenty years, nor is there a meaningful statewide policy for DR achievements which could be relied upon as a forecast of future DR impacts. In light of this, the IOUs are best-positioned to estimate the cost and performance of future DR programs in their service areas. Current DR program costs and results are highly utility- and program-specific. Therefore, there is not a single, transparent data source which could be relied upon to standardize DR assumptions across the IOUs. IOUs should perform a Deliverability Risk Assessment of the likelihood of achieving a given level of DR.

4. Combined Heat and Power

The CARB Proposed Scoping Plan recommendation of 4,000 MW of new CHP should be reflected in the CARB Scoping Plan scenario. IOUs should perform a Deliverability Risk Assessment of the likelihood of achieving different levels of CHP in each scenario.

There are a number of challenges to developing forecasts of CHP penetration. First, sources of publicly available data are limited. In the working group process, CAC/EPUC presented suggested assumptions for CHP penetrations and costs, which

[136] D.08-04-050, OP 5.

were based on a 2005 CEC study of CHP potential.[137] Given that this potential study is now several years old, the CEC is currently working on an updated CHP potential study. However, it is not yet clear whether all of the key assumptions in the study will be updated as part of that effort, or whether the results of that study will be available in time to inform the 2010 LTPP filings.

Second, historic rates of small CHP development may not be applicable in the near future due to the development of a feed-in tariff for small CHP as required by Assembly Bill 1613. The details of the feed-in tariff are still under development in R. 08-06-024, however, the results of this proceeding may point the way towards increased penetration rates for small CHP in the future. In addition, in Decision 08-10-037 the Commission indicated its intention to consider CPUC CHP policy more broadly.[138] A new proceeding on CHP is expected to open in 2009, however the results of that proceeding are not likely to be available in time to inform the 2010 LTPP filings.

Given these data challenges, as well as ongoing work on CHP rules and regulations on-going at the CPUC, staff recommends that, in the absence of an updated CHP potential study,[139] the Commission convene an LTPP CHP working group to discuss the following outstanding questions:

a. What assumptions should be used to develop a CHP penetration scenario that reflects current and expected market trends of CHP cost, performance and penetration?
b. For the CARB Scoping Plan scenarios, how much CHP should be assumed for each IOU service territory, in order to achieve a statewide penetration of 4,000 MW of CHP? What technology types should be assumed for the 4,000 MW of CHP?
c. What assumptions should be applied regarding the performance and cost of representative CHP technologies?

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[137] CEC. (2005). *Assessment of California CHP Market and Policy Options for Increased Penetration,* 500-2005-060-D, April. Available at: http://www.energy.ca.gov/2005publications/CEC-500-2005-060/CEC-500-2005-060-D.PDF

[138] D.08-10-037, at p. 105.

[139] A new CHP potential study is being conducted in the 2009 IEPR. Even if the study is released, prior to the 2010 LTPP, it may be useful to convene the LTPP CHP working group anyways to review the study and address other issues.

d. What is an appropriate mix of topping- and bottoming-cycle CHP resources and what are their respective generation, recoverable waste heat, and emission profiles? [140]

e. What are on-site load impacts of CHP?

f. What are the benefits of CHP in transmission-constrained local reliability areas?

The Total Resource Cost of CHP should reflect the net cost of constructing and operating a CHP facility relative to the cost of obtaining electricity and steam without a CHP facility. The cost should include all incremental capital and O&M costs, taxes and other costs associated with the electric generating component, as well as the net fuel costs (total fuel costs minus the cost of fuel needed to generate a like quantity of steam without the CHP facility). This approach captures an appropriate split of the facility costs between the electric and steam components. The utility cost of CHP that is reflected in the PVRR cost calculation should be calculated per the CHP avoided cost formula adopted in D.07-09-040, unless superseded by a subsequent Commission decision. The total cost of CHP by technology type or by capacity size, should be a topic for discussion in the proposed LTPP CHP working group.

5. Customer-side Distributed Generation

The IOUs should adopt consistent assumptions about the future performance and cost of small-scale (< 5 MW) solar PV cost and, if applicable, other DG such as fuel cells. The deployment of solar PV should be based on expectations regarding solar PV policy goals and the future cost and performance of the technology. The CARB Proposed Scoping Plan goal of achieving at least 3,000 MW of new distributed solar PV by 2020 should be reflected in at least one of the LTPP scenarios, consistent with a Deliverability Risk Assessment of the likelihood of achieving all of the CSI goals. For the 2010 LTPPs, staff believes that the IEPR Base Case forecast will be an appropriate estimate of CSI penetration.

[140] See, for example, *Comments of the California Large Energy Consumers Association and the California Manufacturers and Technology Association in Response to the Questions Posed in the August 11, 2008 CPUC Staff Notice of Workshop on Planning Scenarios and Metrics*, served August 22, 2008, at p.2.

The CSI program, which includes the New Homes Solar Partnership, is administered by the CPUC and the CEC. These programs include declining customer incentive structures which should be reflected in the utility present value revenue requirement calculation. The total cost metric should be based on the entire expected retail cost of rooftop solar PV, including installation, regardless of whether the customer or the utility pays.

The assumptions of the energy delivered and peak load contribution of distributed solar should be established based on historical performance of the CSI installations as determined in the program measurement and valuation studies performed for the CPUC.[141]

6. Resource Additions and Retirements

Staff generally concurs with the Joint–IOU Report recommendations on resource additions and retirements (See Appendix B). IOUs should specify resource additions and retirements, as listed in the standardized physical system capacity need tables (Appendix C). Each utility should specify which additions (specifically) and which retirements (in aggregate) are assumed. The IOUs should describe the criteria used to make the resource addition and retirement assessment, allowing stakeholders to review these assumptions. Staff recommends that "Known/High Probability Additions" in the physical system capacity need table should contain resources that have a contract in place, have been permitted, and have construction under way. Criteria for "Other Utility Planned Additions NQC" and "Other non-Utility Planned Additions NQC" should include resources that have a contract, but have not yet begun construction.

All scenarios, except the OTC policy/nuclear retirement scenario, should apply the same set of assumptions regarding the impact of OTC based on the best information available at the time of the LTPP analysis. The impact of a state decision on OTC could have potentially large ramifications for local reliability and capacity. The SWRCB is expected to adopt a final policy on OTC by the end of 2009. If adoption of a final OTC rule is still pending by time LTPP assumptions are finalized, the IOUs should make reasonable

[141] See, for example, *CPUC Self-Generation Incentive Program: Solar PV costs and incentive programs* February 2007.

estimates of the OTC phase-out schedule in the anticipated final SWRCB rule, and include these in their base case assumptions regarding the retirement or re-powering of generators to comply with expected OTC rules. If, however, the SWRCB adopts a final rule prior to the development of 2010 LTPP portfolios, then these assumptions should be incorporated into the LTPP, subject to a Deliverability Risk Assessment.

In Section 3.2.1, staff anticipated that the 2010 and subsequent LTPPs would authorize new resources on the basis of system need and/or local need, in large part due to OTC policies that could shut-down plants in local areas.

7. Re-contracting Rate (Bundled Plan Only)

For the Bundled Plan, the IOUs should make utility-specific assumptions regarding the rate at which contracts with existing plants are renewed. There is no need to standardize, as each utility may have inherently different success rates that are unique to their region or other circumstances.

8. Uncertainty Band and Probability of Occurrence

As described in Section 3.6, staff recommends that the IOUs include "High-Need" and "Low-Need" sensitivities to assess the impacts of different levels of policy-driven resource achievement or unexpected variation in load not already accounted for in the PRM. The utilities should represent the high- and low-need sensitivities as upper and lower bounds of an "uncertainty band" around the residual net short. Because there are multiple drivers of need, each with their own level of uncertainty, it is important to consider the cumulative effect of these uncertainties. Therefore, the utilities should estimate the probability of occurrence of the base case residual net short, "High-Need" and "Low-Need" sensitivities and present a rationale justifying the estimates.

3.8.2 New Resource Cost and Performance Assumptions

This section includes recommendations for inputs and assumptions on the cost and performance of new resources. It is important that the LTPPs be based on similar assumptions about new resources in order for the cost impact calculations to be meaningful and comparable. This section includes both general recommendations about sources of cost and performance data, as well as specific recommendations for the 2010 LTPPs, as summarized in Table 8 below.

Table 8: Recommendations for LTPP inputs and assumptions: New resource cost and performance assumptions

Category	Recommended Source	Recommended for 2010 LTPPs
1. Renewable resource availability, cost and performance by location	IOUs propose a consistent set of renewable resource availability, cost and performance data by location based on RETI and subsequent studies	Cost and performance data should be derived from RETI assumptions, adjusted to reflect recent cost trends
2. Conventional and other resource cost and performance	IOUs propose a consistent a set of assumptions based on publicly-available data sources	Cost and performance data for CCGT plants should be based on the MPR values
3. New generation tax and financing assumptions	IOUs propose a consistent a set of assumptions and methodology for calculating the levelized cost of energy	IOUs propose a consistent set of assumptions and methodology for calculating the levelized cost of energy
4. On-peak capacity	NQC per RA proceeding	NQC per RA proceeding
5. Transmission cost assumptions	IOUs propose a consistent methodology for calculating the transmission cost associated with accessing renewable energy zones	Transmission costs should be based on cost information developed by the CAISO for RETI
6. Distribution cost assumptions	IOUs propose a consistent methodology for calculating the distribution costs associated with each portfolio, based initially on the CPUC EE Avoided Cost methodology	CPUC EE Avoided Cost methodology

<u>1. Renewable Resource Availability, Cost and Performance by Location</u>

For the 2010 LTPPs, renewable energy resource availability, cost and performance data should be derived from the RETI data, based on technology types and the physical location of the resource. This approach was generally supported by non-IOU members of the working groups,[142] although IOUs indicated a preference to use RPS bid data, when available. The RETI numbers may need to be adjusted before the 2010 LTPPs are filed to reflect current cost trends. The IOUs should present any adjustments to stakeholders and provide an opportunity for comment prior to conducting the LTPP analysis.

For subsequent LTPPs, the IOUs will need to rely on a similar renewable energy cost and performance study. If there are periodic updates to RETI, this could continue to serve as the source for renewable energy cost and performance data. If there are no updates to RETI, the IOUs should jointly conduct or commission a study to develop updates to the RETI assumptions to take into consideration changes in capital costs, operating performance, resource availability, and other key factors.

2. Conventional and Other Resource Cost and Performance

The IOUs should propose a consistent set of assumptions regarding the cost and performance of conventional resources such as CCGTs and CTs and other generation resources such as nuclear, IGCC with carbon capture and sequestration, fuel cells, and others. The assumptions should be based on publicly-available data sources. Stakeholders should have the opportunity to review and provide comment on the IOU-proposed assumptions prior to commencing the analysis. For the 2010 LTPPs, the IOUs should rely on the MPR methodology for assumptions about the cost and performance of gas-fired resources since that methodology has been thoroughly vetted through several iterations of stakeholder process. In subsequent years, if the MPR is no longer used or calculated by the Commission, the IOUs should propose new assumptions based on publicly available data from recent plant construction.

3. New Generation Financing and Tax Assumptions

The IOUs should propose a consistent set of assumptions about new generation tax and financing assumptions and a common methodology for calculating the cost of a power purchase agreement (PPA) given an underlying set of capital, O&M and fuel cost assumptions. As a default, the IOUs should assume independent power producer ("IPP")

[142] See, for example, CEERT pre-workshop comments on scenarios and metrics, at p. B-1 – B-3.

ownership and financing of all new generation. The PPA should be structured to equal the minimum of useful life of the asset, e.g., 20 years. Common assumptions should be used regarding IPP debt and equity costs and the proportion of equity in the project financing. The PPA price should be sufficient to achieve a debt-service coverage ratio of at least 1.5, independent of any tax equity benefits. Tax treatment should include all applicable federal and state taxes and tax benefits. IOU-specific financing rates are appropriate for investments made by an IOU, such as distribution or transmission. Finally, staff concurs with the IOUs' recommendation to report all costs in nominal terms (See Appendix B).

4. On-peak Capacity

Assumptions about renewable energy on-peak capacity should be derived from the most recent Resource Adequacy (RA) net qualifying capacity assumptions (e.g., R.08-01-025 or its successor).

5. Transmission Cost Assumptions

In the PVRR and TRC calculations, IOUs should include scenario-appropriate estimates of the total transmission revenue requirements associated with each portfolio. For costs associated with existing transmission, IOUs should develop and propose appropriate assumptions for how those costs will change over time. For new transmission, the CAISO has committed to providing high-level cost estimates for the RETI Phase 2 analysis. The IOUs should use these estimates for new transmission to the extent that they are suitable for the level of geographic granularity in the LTPPs. In the event that CAISO transmission costs are not available, the IOUs should propose a consistent set of transmission costs for stakeholder review.

6. Distribution Costs

In the PVRR and Total Resource Cost calculations, IOUs should include scenario-appropriate estimates of the distribution costs associated with each portfolio. For costs associated with existing distribution, IOUs should develop and propose appropriate assumptions for how those costs will change over time. New distribution costs may differ by portfolio, as customer-side generation and demand reduction measures could result in avoided distribution costs. The IOUs should propose a consistent methodology for estimating distribution cost savings. For the 2010 LTPPs, the methodology should be based on the distribution component of the CPUC's EE Avoided Cost methodology.

3.8.3 Market Price Forecasts

This section describes our recommendations for developing inputs and assumptions with respect to fuel price forecasts, CO_2 allowance price forecasts, and allocation of CO_2 allowances. Both generalized recommendations for the LTPPs and specific recommendations for the 2010 LTPP cycle are summarized in Table 9 below.

Table 9: Recommendations for LTPP inputs and assumptions: Market price forecasts

Category	Recommended Source	Recommended for 2010 LTPPs
1. Natural Gas Price	Gas price forecasts should be based on the most recent MPR methodology, or if the MPR is no longer in use by the Commission, the IOUs should propose a consistent forecasting methodology.	Gas price forecasts should be based on the most recent MPR methodology, with numerical values updated for recent changes in market prices
2. Biomass & Coal Price	IOUs propose consistent price forecasting methodology	IOUs propose consistent price forecasting methodology
3. Electricity Market Price	IOU-specific methodology	IOU-specific methodology
4. CO2 Price	MPR CO_2 forecasting methodology	Use the CO_2 price forecast from the most recent MPR
5. GHG Policy Assumptions	Energy Division proposes GHG policy assumptions for stakeholder review	Energy Division proposes GHG policy assumptions for stakeholder review

<u>1. Natural Gas Fuel Price Forecast</u>

The Assumptions and Data Working Group did not achieve consensus a methodology for forecasting the price of natural gas for the 2010 LTPPs. Some parties advocating using the methodology for the natural gas fuel price forecast applied in the 2008 MPR, D. 08-10-026. The latest MPR methodology relies solely on published prices for natural gas futures contracts traded on the New York Mercantile Exchange for natural gas commodity delivered to Henry Hub, Louisiana. However, previous MPR methodologies relied on a blend of NYMEX prices and a "fundamentals" forecast for the period more than six years out. SCE maintains that the previous approach is more appropriate for long-term natural gas prices than relying on NYMEX futures prices.

Subject to change by the Commission in subsequent MPR decisions, the IOUs should use the MPR gas price forecasting methodology for the "base case" gas price forecast in the LTPP, in order to avoid re-arguing an issue that the Commission has decided very recently. This adheres to Working Principle C on common resource planning assumptions. If the MPR is no longer in use by the Commission, staff recommends that the IOUs coordinate to propose a common forecasting methodology for stakeholder to review.

The actual assumed gas prices should be updated as late as possible in the planning cycle in order capture any recent events affecting natural gas futures prices.

2. Biomass & Coal Fuel Price Forecast

The IOUs should propose a consistent set of biomass, coal and other non-gas fuel price forecasts. As an example of an approach that could be pursued by the IOUs, RETI consultants estimated biomass feedstock costs by obtaining data from the Green Power Institute, updated to 2008 costs, and adapted for the resources identified in the California Biomass Collaborative report.[143] At a minimum, a common and comparable methodology should be applied across all IOUs. Stakeholders should have the opportunity to review and comment on the proposed cost assumptions.

[143] Black & Veatch. (2008) *RETI Phase 1B Resource Report*, August, at p. 4-4. www.energy.ca.gov/reti/documents/2008-08-16_PHASE_1B_DRAFT_RESOURCE_REPORT.PDF

3. Electricity Price Forecasts

In California, electricity prices are tied very closely to the price of natural gas, and electricity price movements will therefore strongly reflect underlying gas price assumptions. Electricity prices play a relatively small role in LTPPs, since the IOU plans will result in portfolios that are fully hedged on a planning basis. Moreover, each IOU currently relies on its own methodology for calculating electricity prices, so there appear to be no convincing rationale for requiring the use of a single methodology. Thus, electricity price forecasts need not be uniform across IOUs. However, the forecasts should reflect the same, coordinated input assumptions, and should vary similarly based on the forecasted demand, CO_2 prices and fuel prices of each scenario.

4. CO_2 Price Forecast

For the "base-case" CO_2 price forecast, staff recommends that the IOUs apply the CO_2 price forecast methodology applied in the 2008 MPR Decision D.08-10-026, unless superseded by another decision. When the IOUs file their 2010 plans, neither California nor the Western Climate Initiative is expected to have a fully-functioning CO_2 market. Likewise, in the event that the federal government pursues a nation-wide cap and trade program, it is unlikely that such a program would be operational by 2009 or 2010. Therefore, staff does not expect that relevant, real price data will be available when the IOUs file their plans.

The MPR Decision (D.08-10-026) recommends that the modeling methodology for estimating GHG compliance costs be:

- publicly available;
- based on multiple scenarios and sources of information;
- based on realistic and public assessments of policy proposals and scenarios; and
- based on the most current reliable information that conforms to the other three criteria.[144]

[144] D.08-10-026, at p. 31.

Staff finds that these criteria will provide a reasonable basis for developing a "base-case" CO_2 price forecast for future LTPP cycles. For the 2010 LTPPs, the IOUs should use the CO_2 prices from the 2008 MPR proceeding. This will avoid re-arguing an issue the Commission has recently decided, particularly in light of the ongoing uncertainty about the trajectory of state and federal GHG regulations.

5. GHG Policy Assumptions

This category of inputs refers to policy assumptions such as the allocation of CO_2 allowances or CO_2 allowance auction revenue, the ability to use offsets from non-regulated sectors (either domestically or internationally), the ability to substitute emissions from non-CO_2 GHGs such as N_2O or SF_6, the ability to bank and/or borrow offsets to smooth out fluctuations in year-to-year compliance obligations, and other factors. Staff recommends that Commission staff propose a set of policy assumptions based on the most recent regulatory and legislative developments at both the state and federal level, where needed to supplement the policy directions set out in the CARB Scoping Plan.

3.8.4 Accompanying Studies

This category includes recommendations for the additional studies that should accompany the LTPPs, including a Deliverability Risk Assessment, a Renewables and Transmission Study and a Renewables Integration Study. Specific recommendations are summarized in Table 10 below.

Table 10: Recommendations for LTPP inputs and assumptions: Accompanying studies

Category	Recommendation	Recommended for 2010 LTPPs
1. Deliverability Risk Assessment methodology	IOUs propose a consistent methodology for estimating the delivery risk associated with each resource category, unless provided by CPUC staff or external sources (e.g., IEPR)	Various methodologies as described for each resource type in Section 3.8.1 and summarized in Table 10 below.

Category	Recommendation	Recommended for 2010 LTPPs
2. Renewables and Transmission Study	IOUs propose a consistent methodology for allocating the resources and transmission costs from a given area among the three IOUs and other LSEs	RETI and CPUC 33% RPS Implementation Analysis methodology
3. Renewables Integration Study	IOUs propose a methodology for assessing any firming, shaping and integration costs associated with intermittent renewable resources	Upcoming 2009 CAISO 33% RPS integration study

1. Deliverability Risk Assessment

As described above in Section 3.2.5, staff believes that a Deliverability Risk Assessment is a necessary component of the System Plan. This element of the Plan must be highly coordinated among the IOUs to ensure that the IOUs make consistent assumptions about the efficacy, particularly of demand-side programs, and that RA resource procurement authority is granted to the IOUs on a consistent basis. The output of the Deliverability Risk Assessment is a conservative, yet reasonable, forecast of expected achievements for each type for each year of the planning horizon. Deliverability Risk Assessments should be made on base case and alternative case assumptions, as summarized in Table 12.

Table 11 summarizes the recommended sources for Deliverability Risk Assessments, which could be undertaken in various forums. As can be seen from the table, the IOUs would only be required to produce these for three resource types (DR, CHP, and fossil) in the 2010 LTPP, because others would come from staff or external sources. For example, the CPUC has undertaken one aspect of this assessment with its 33% RPS Implementation Analysis. Staff recommends that the IOUs use the results of this analysis for the renewables component of the Deliverability Risk Assessment for the 2010 LTPPs, and that this analysis form the starting point for future analyses. Similarly, the IEPR load forecast includes conventions to estimate reasonably expected EE and self-generation (CSI and other DG) achievements of "committed" programs, as well incremental impacts likely to occur from "uncommitted" EE programs. Thus, to the extent provided, no additional adjustment is necessary for these programs. If the Commission develops similar studies for other programs (e.g., CHP), the IOUs should be required to use these analyses for their Deliverability Risk Assessments. However, the IOUs should conduct their own Deliverability Risk Assessment for any component that the Commission does not undertake using a consistent methodology. Staff recommends that the IOUs coordinate to propose a methodology for stakeholder review.

Table 11. Sources for Deliverability Risk Assessments in the 2010 LTPP by resource type

Category	Recommended for 2010 LTPPs
Energy Efficiency (EE)	The lesser of: • 100% TMG goal (D.08-07-047, OP 3), or • 2009 IEPR forecasts of embedded (committed) and uncommitted EE, based on CEC's "reasonably expected to occur" standard (See Section 3.8.1)
Demand Response (DR)	IOUs propose a consistent methodology pursuant to Load Impact Protocol guidelines (See Section 3.8.1)
Customer-side DG, including CSI	2009 IEPR forecasts of embedded self generation, based on CEC's "reasonably expected to occur" standard (See Section 3.8.1)
Combined heat and power (CHP)	Commission convenes an LTPP CHP working group to produce estimates (See Section 3.8.1)
Renewables	33% RPS Implementation Analysis, with appropriate updates
Fossil additions	*Joint-IOU Report* recommendation to include two categories: 1. Known/High Probability Additions have a contract, permits and construction is well under way. 2. Other Planned Additions have a contract, but construction has yet to begin

2. Renewables and Transmission Study

The IOUs should also propose a methodology for allocating the output of new renewable energy projects facilitated by new transmission lines among the three IOUs, municipal utilities, ESPs, and others. The LTPPs should develop a consistent, coordinated set of renewable energy resources that avoids double-counting of resources in a particular area – i.e., that does not assume that more than one utility (whether IOU or POU) is relying on the same renewable resource. One method for ensuring this is to develop a Renewables and Transmission Study that selects resources from a statewide renewable energy resource supply curve sufficient to meet the statewide RPS goals that are then be allocated among the IOUs and other entities. For the 2010 LTPPs, the methodology should be based on the CPUC's 33% RPS Implementation Analysis. For subsequent plans, the IOUs should propose a methodology for stakeholder review, with a preference for using an existing, publicly-review and available methodology.

3. Renewables Integration Study

The IOUs should propose a methodology for assessing the cost of firming, integrating and shaping new intermittent renewable resources. The methodology should be robust enough to incorporate differences in the cost of integrating different types of resources (e.g., wind vs. solar) as well as variations in the prevailing output profile of similar resources in different locations (e.g., coastal vs. inland wind resources). The methodology should include both variable costs of increased requirements for regulation and other ancillary services as well as the fixed costs of any new resources that are required as a result of selecting intermittent resources for a given portfolio.

For the 2010 LTPPs, the IOUs should make maximum use of the integration analysis that the CAISO is currently undertaking using cases from the CPUC's 33% RPS Implementation Analysis. The IOUs have indicated their support for aligning the CAISO's study results with the 2010 LTPP.[145] Depending on the results of the CAISO analysis, some modifications may be required in order to make it apply to resource portfolios other than those specifically modeled by the CAISO. For the 2010 and subsequent plans, the IOUs should propose any necessary modifications or updates to the

[145] For example, in comments to the CAISO's 33% integration study, PG&E encouraged the CAISO to "proceed with the study expeditiously as it is important the study remain on track to inform the CPUC's 33% RPS Implementation Study and the Long-Term Procurement Plan (LTPP) Proceeding's need determination and procurement filings." *PG&E Comments on Integration Studies*, at pp. 1-2. www.caiso.com/2344/23448c0c5b680.pdf.

CAISO analysis, and stakeholders should have the opportunity to review and provide comment prior to commencing the analysis.

3.8.5 Alternative Inputs and Assumptions for Scenarios and Sensitivities

The inputs and assumptions presented in the preceding sections are recommended to be the Base Case assumptions, applied unless alternative values are appropriate. However, staff also recommends that the IOUs run a number of alternative cases, either as Scenarios or Sensitivities. These cases are described in detail in their respective sections above. Table 12 below summarizes our recommendations for how the inputs and assumptions should look for each of our recommended required alternative cases. Some of the values would be the same for all cases, while others would vary depending on the case.

Table 12: Recommendations for 2010 LTPP base case and alternative case assumptions

Category	Source for Base Case Assumptions	Alternative Case Assumptions
Load forecast	IEPR base case load forecast	**High-Need Sensitivity (System and Bundled Plan):** Effects of higher weather, economic, and demographic drivers not already accounted for in the PRM. **Low-Need Sensitivity (Bundled Plan):** Higher levels of departing load
Energy efficiency (EE)	IEPR forecast of embedded and uncommitted	**Low-Need Sensitivity (System Plan):** EE “stretch” goals.
Demand response (DR)	IOUs propose methodology pursuant to the guidelines in proposal	**Low-Need Sensitivity (System Plan):** DR “stretch” goals.

Category	**Source for Base Case Assumptions**	**Alternative Case Assumptions**
Combined heat and power (CHP)	CPUC interpretation of CARB goals, subject to Deliverability Risk Assessment	**Low-Need Sensitivity (System Plan):** CHP "stretch" goals.
Customer-side DG, including California Solar Initiative (CSI)	IEPR forecast of embedded CSI	**Low-Need Sensitivity (System Plan):** CSI "stretch" goals.
Resource additions and retirements	IOUs propose consistent methodology (*Joint-IOU Report*)	Same for all cases
Re-contracting rates (Bundled Plan only)	IOU-specific	Same for all cases
Renewable resource availability	Derived from RETI assumptions	**Least-cost Renewables Scenario (if different from CARB Scenario):** Increased reliance on in-state resources, out-of-state delivered resources, or out-of-state RECs, consistent with RPS law. **Transmission-Constrained Scenario:** No new renewable resources allowed in areas which would require substantial new transmission construction
Renewable resource cost	Derived from RETI assumptions	**Technology Cost Sensitivity:** Substantial cost reductions for solar PV, solar thermal, and other immature technologies
Conventional and other resource cost and performance	MPR values for CCGT, IOUs propose for others	Same for all cases
New generation tax and financing assumptions	IOUs propose consistent methodology	Same for all cases

Category	Source for Base Case Assumptions	Alternative Case Assumptions
On-peak capacity	NQC per RA proceeding	Same for all cases
Transmission cost assumptions	Derived from RETI assumptions	Same for all case
Distribution cost assumptions	CPUC EE Avoided Cost methodology	Same for all cases
Natural Gas Price	Most recent MPR methodology	**Natural Gas Price Sensitivities:** Feasible extreme high and low values
Biomass & Coal Price	IOUs propose consistent methodology	**Natural Gas Price Sensitivities:** Coal and oil prices should be adjusted to reflect appropriate price elasticity
Electricity Market Price	IOU-specific	**Natural Gas Price Sensitivities:** Electricity prices should be adjusted to reflect appropriate price elasticity
CO_2 Price	Use the CO_2 price forecast from the most recent MPR	**CO_2 Price Sensitivities:** Feasible extreme high and low values
GHG Policy Assumptions	Energy Division proposes GHG policy assumptions for stakeholder review	**Natural Gas-Only Scenario**: No strict resource mandates, but should reflect need to acquire CO_2 allowances
Deliverability Risk Assessment methodology	Various methodologies as described for each resource type in Section 3.8.1, and summarized in Section 3.8.4	**High-Need Sensitivity (System Plan):** Decreased achievement of policy-driven resource goals **Low-Need Sensitivity (System Plan):** Increased achievement of policy-driven resource goals
Renewables and Transmission Study	RETI and CPUC 33% RPS Implementation Analysis methodology	**Lowest-Cost Renewables Scenario:** All out-of-state renewables allowed **Transmission-Constrained Scenario:** No new renewable resources allowed in areas which would require substantial new transmission construction

Category	Source for Base Case Assumptions	Alternative Case Assumptions
Intermittent renewable resource integration costs	Upcoming 2009 CAISO integration study	**Technology Cost Sensitivity:** Potentially lower costs due to lower cost of storage

3.9 Presentation of Information

The final report should contain enough technical detail to thoroughly explain and represent the analysis undertaken, but should also summarize the key findings of the report in a manner that is accessible to a broad audience.

Past LTPPs were developed for the primary purpose of obtaining Commission approval of an IOU's net short position in order to authorize resource procurement. In contrast, the 2010 and subsequent System Plans will have a wider audience and a broader purpose. The System Plan is designed to address important questions related to interpretation and implementation of state energy policy in addition to addressing the procurement authorization issue. As a result, the audience for the final report will include the Commission as well as policy makers, other agencies and a diverse set of stakeholders. The LTPP analytical effort will be far more impactful if the IOUs are able to dedicate more resources to explaining and summarizing the analysis and findings to non-technical audiences.

Aspen/E3's *Best Practices Report* revealed that some utilities use the same communications staff responsible for producing the utility's annual report to create their resource plan reports. Staff recognizes that the development of LTPP filings already requires significant time, energy and resources on the part of the IOUs. However, staff recommends that the IOUs devote significantly more resources and engage communications professionals from either inside or outside of their organizations in order to produce reports that help to educate energy stakeholders about the key questions addressed in the plans.

4 Implementation Alternative: A Joint System Plan

The recommendations presented in this proposal have, thus far, assumed that the IOUs continue to file individual System and Bundled Plans. The System and Bundled Plans would continue to provide the IOUs with authorization to procure resources for reliability and bundled load service, respectively. However, many of the key questions facing the state's electric utilities today have to do with the challenge of meeting aggressive state policy goals. The answers to these questions affect all electric ratepayers in the state, not just the bundled ratepayers of IOUs. This drives two of our principal recommendations: (1) that the System Plans evaluate the impacts of alternative strategies for meeting aggressive state policy goals, both in terms of cost to electric ratepayers and in terms of the need for accompanying electric infrastructure; and (2) that the IOUs engage in a high degree of coordination in order to provide the Commission with consistent, high-quality information that allows it to make informed decisions about these high-level questions.

There are a number of areas in which staff has recommended that the utilities coordinate to develop consistent approaches. In particular, staff believes that the Plans should be conducted with a consistent set of input assumptions with respect to fuel prices and resource cost and performance, that the IOUs should analyze a consistent set of scenarios and conduct sensitivity analysis of the same variables at the same price levels, and that the renewables and Deliverability Risk Assessment studies that staff recommends accompany the LTPPs be conducted using consistent methodologies. Staff believes such coordination is critical to the success of the effort to analyze the effect of state policies.

Given the nature of the questions that staff recommends the System Plans analyze, the high level of coordination that staff believes is necessary, and the level of effort that analyzing these questions will require, staff believes it is worth considering whether a single, jointly-filed System Plan would be a preferable alternative to three, highly coordinated individual System Plans. There are a number of pros and cons to a Joint System Plan, some of which are discussed below. The principal advantage is that the Joint System Plan alternative would ensure, by its very nature, that the plans are coordinated and based on consistent information. However, there are also some disadvantages as described below, and a jointly-filed plan would be a substantial departure from past practice in the LTPP proceeding. Staff does not recommend requiring a Joint System Plan as part of the Resource Planning Standards at this time, but raise the idea in order to elicit comment from Parties.

4.1 Description of the Joint System Plan Alternative

Figure 8 provides a simplified process overview of a proceeding in which the IOUs individually Coordinated System Plans and Bundled Plans, while Figure 9 shows an overview of the Joint System Plan alternative. Figure 8 shows separate tracks for each IOU, with the inputs and methodologies coordinated at the outset. The chart shows how the Commission decision to adopt plans is, in effect, three decisions (one for each IOU) wrapped into one large decision. Figure 9 shows how a Joint System Plan alternative leads to a single decision from the Commission to approve, modify or reject a single, System Plan.

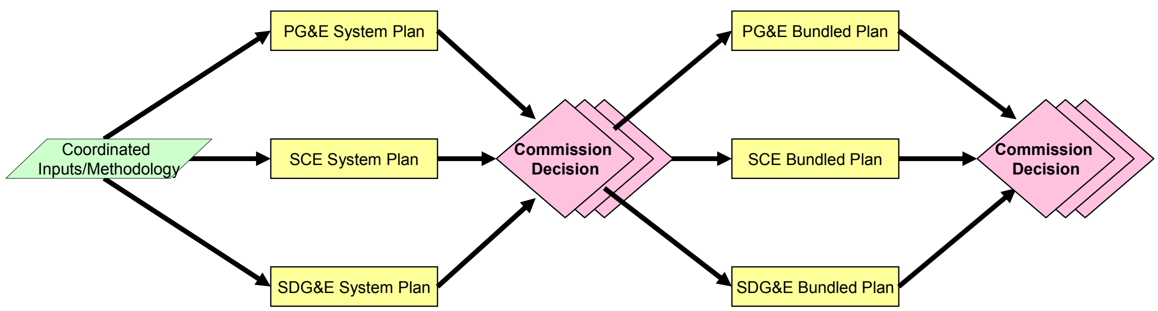

Figure 8. Simplified process overview of Coordinated System Plans

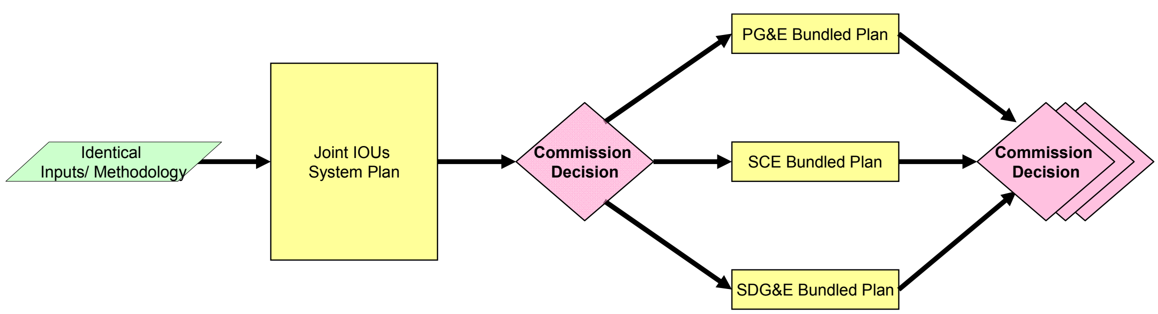

Figure 9. Simplified process overview of a Joint System Plan alternative

While one function of a Joint System Plan would be to analyze, at the joint-IOU level, the effects of alternative RPS and GHG strategies, the Joint System Plan would still culminate in the Commission granting procurement authority for system resources. Thus, in addition to the analyses described above in Section 3, a Joint System Plan would need an additional step to allocate the responsibility for procuring system resources among the IOUs. There are a number of ways of accomplishing this. As a baseline, a Joint System Plan could continue to calculate the need for system resources based on the load connected to each IOU, just as if the plans were being conducted by the IOUs. But, the Joint System Plan alternative introduces the possibility that the IOUs could develop and propose alternative formulations to the Commission.

In any collaborative process, disagreements and differences of opinion are likely to arise. It is impractical to suggest that the IOUs will necessarily reach consensus regarding all aspects of a Joint System Plan, although consensus should be the goal. To avoid the potential for deadlock among the IOUs in the development of a Joint System Plan, each IOU should be given the opportunity to file a "dissenting opinion," which would describe any areas of minor disagreement with the final findings of a Joint System Plan. This additional information would be taken into consideration by the Commission as it weighs its final decision regarding a Joint System Plan. In the worse case, if the IOUs could not agree on fundamental aspects of the Plan such as a Preferred Portfolio, they would have the opportunity to file separate analysis supporting their own Preferred Portfolios. The IOUs would be strongly discouraged from doing so, however, because separate filings would defeat the purpose of a Joint System Plan.

As with the individual System Plans alternative, there is an important role for CPUC staff and stakeholders to play in the development of the LTPP data inputs, scenarios, and sensitivities and in the interpretation of results. The process for producing a Joint System Plan would be essentially the same as has been previously described in Table 1 for the Coordinated System Plans alternative (see Section 3.3.2). The only difference is that individual IOU actions are replaced by joint actions.

4.2 Potential Benefits of the Joint System Plan Alternative

The potential benefits of the Joint System Plan alternative include:

1. **Workload synergies and efficient use of IOU analytical resources.** The System Plans analysis that staff recommends would require a significant level of effort on the part of the IOUs. A Joint System Plan would provide an opportunity to harness the collective resources of the three IOUs and provide an improved product at a lower cost.
2. **Consistent inputs and methodologies.** A Joint System Plan would create a common System Plan and, thus, ensure the maximum level of comparability among IOU System Plans, which enhances benefits to related proceedings at the CPUC and sister agencies. A Joint System Plan would encourage the IOUs to more closely coordinate a generation and transmission development vision in order to ensure that ratepayer dollars achieve the greatest possible benefit. Working collectively, the technical expertise of the combined IOU technical staffs has the best chance of resolving seams issues between the IOU systems. The principal example is the ability to harmonize assumptions about the configuration of the transmission system and to identify the highest priority transmission projects to meet the collective obligation of the CPUC jurisdictional entities in conforming to State goals.
3. **Consistent information about progress on state policy goals.** A Joint System Plan would create greater clarity regarding strategies for and impediments to achieving state policy goals. Because much of the focus of the System Plan is on achieving state policy, the Commission needs consistent information about the costs and benefits of alternative means of doing so. A Joint System Plan would present a single, unified set of information that would aid its decision-making. This is particularly true with regard to RPS policy, where overcoming the transmission and generation “chicken-and-egg” problem would be facilitated by a single, statewide plan produced by three of the largest Participating Transmission

Owners in California. A joint planning exercise may reveal opportunities for joint projects and collaboration to achieve common goals such as RPS compliance.

4. **More flexibility.** Ensuring a high degree of coordination among three individual resource plans requires that the Commission issue prescriptive guidelines regarding many of the assumptions and methodologies. However, less prescription may be required for a Joint System Plan, where coordination is inherent. For example, while staff expects that the IOUs will need to model the hourly output profiles of various combinations of renewable and conventional resources, the IOUs, in consultation with the CPUC and stakeholders, would be best positioned to determine how to approach the analytics of the LTPP, and to decide which questions require rigorous production simulation modeling and which questions are better answered with alternative modeling approaches.
5. **Simplify and expedite eventual approval of bundled procurement plans.** CPUC and parties' review of the Bundled Plans should be simplified and expedited. One Joint System Plan would allow each IOU to present its bundled procurement plan against the backdrop of this common System Plan.
6. **Easier to administer.** A Joint System Plan may be easier to administer than individual plans, which would require technical assistance and staff time to effectively act as liaison between the IOUs. Overlapping issues, such as transmission, would require less coordination on the part of CPUC staff, because the IOUs would be working together on the same plan, using the same assumptions and methodologies. Further, CPUC staff review and analysis of submitted plans would be simplified by having only one plan to read. The need for staff analysis to determine whether discrepancies among plans are due to legitimate differences or flaws would be greatly reduced.

4.3 Potential Costs and Risks of the Joint System Plan Alternative

There are also costs and risks associated with the Joint System Plan alternative. These include:

1. **Excessive standardization.** It may be inappropriate to impose a single set of methodologies and inputs on three different utilities, each with their own customer bases and unique perspectives. A Joint System Plan may impair the IOUs (and the Commission's) ability to take advantage of unique opportunities that arise from differences in each IOU's system. Requiring the IOUs to rank, score, and identify a common "preferred" portfolio may be inappropriate, if there are benefits to differentiation.
2. **Logistical and process challenges.** The three IOUs must work together to develop the Joint System Plan, which could prolong the planning cycle (or prove infeasible), if the IOUs cannot work together effectively, agree on key assumptions/methodologies, and resolve disputes or address irreconcilable differences in dissenting opinions. In that instance, the Commission may be required to revert to more prescriptive direction during the middle of the proceeding, possibly resulting in procedural delay. Important mechanical issues, such as who leads the project, who does the modeling, and how tasks are delegated, would also need to be resolved by the IOUs. In the EE proceeding, the three IOUs were ordered to collaborate on a joint, statewide Energy Efficiency Strategic Plan.[146] Requiring a similar model of cooperation in a Joint System Plan might be more difficult, since the investment dollars associated with generation and transmission projects are higher. At the same time, the proceeding would not result in binding decisions about those investments, except with respect to system reliability resources.
3. **Central planning.** A Joint System Plan may be perceived as a departure from the Commission's goal of advancing markets, insofar as it represents a more centralized planning model (even if plans are indicative). On the continuum of market-based versus planning-induced investment signals, a Joint System Plan could be viewed as trending towards a central planning model of building necessary infrastructure to achieve state policy goals. It is important to clarify that, a Joint System Plan, like individual System Plans, would be neutral on resource ownership and procurement mechanisms.

[146] D.07-10-032, OP 1.

4. **Perception of opaqueness.** A Joint System Plan must be presented to the Commission and stakeholders in a clear and transparent way, which allows the Commission to make a well-informed decision regarding the outcome of the Plan. But, because the IOUs would be agreeing on draft inputs and results and making joint decisions during the course of a joint modeling process, rather than individually, there is a risk that stakeholders would perceive the IOUs exercising greater influence over the modeling exercise. Parties already complain that the IOUs control all the information in regulatory proceedings, and this arguably exacerbates the concern. Thus, a Joint System Plan may require extra process in the form of workshops or working groups to ensure that parties are informed and have a say in the decisions being made. It may be advisable for the IOUs to designate a handful of parties to serve as observers and/or participants in some of the joint meetings that would be necessary to coordinate the work. If the stakeholder process is not perceived well, a Joint System Plan could increase litigation risk.
5. **Unintended consequences of IOU agreement.** Another potential pitfall is the risk that IOUs may agree on a plan that is widely opposed by stakeholders and/or CPUC staff. This may result in a plan that has more momentum and is more difficult for stakeholders to influence than individual plans.

5 Potential Linkages to other Commission Proceedings and External Processes

The LTPP proceeding is the CPUC's "umbrella proceeding," whose primary purpose is to, "integrate all procurement policies and related programs."[147] The recommendations in this report seek to improve the capability of the LTPP proceeding to uphold this important task of serving as the Commission's umbrella proceeding, by strengthening the connections between the CPUC's diverse resource procurement policies and programs. The purpose of this section is to offer more specific ideas about conceivable ways that detailed information and analysis from the LTPP System Plan could be used in other forums. Staff purposefully did not limit the scope of these potential linkages to current program designs; indeed, most linkages would require program changes, and in some cases (e.g. RPS), enabling changes to legislation. Further investigation and the ultimate decision whether to actualize these linkages is deferred to the procurement-related dockets themselves, as set forth in the Scoping Memo.[148]

Figure 10 below summarizes these possible relationships, some of which (e.g., CEC load forecast) are explicitly recommended in the Section 3; while others are offered for illustration purposes.

As has been said, the decision to explore these potential linkages further and decide whether/how to use the information (if at all) is left to decision-makers in other venues. Indeed, the current scope of the LTPP proceeding would preclude the Commission from making broad policy determinations on resource-specific issues.[149] But, *even if none of these potential connections materialize through actions taken in other proceedings, the detailed information in the System Plan is needed, regardless*, to effectively determine need for new fossil resources, pursuant to the Commission's more rigorous standards for post-AB32 fossil procurement. Decision 07-12-052 states: "Even in a GHG-constrained world, fossil resources are likely to play a vital role, due to flexibility and reliability

[147] *R.08-02-007 OIR,* at p.6.

[148] August 28, 2008 *ACR/Scoping Memo*, at p. 4 and footnote #4.

[149] See "LTPP Scoping Standard," *R.08-02-007 OIR*, at p. 12.

attributes; but the IOUs' plans do not demonstrate the analytical rigor to draw this conclusion."[150]

To illustrate how a Commission decision adopting the IOUs' LTPP System Plan could influence other venues, several hypothetical outcomes of the 2010 (and future) LTPP decision(s) are described in the sections below. The level of detail addressed in future LTPP decisions, would necessarily vary by topic, and would ultimately depend on the Commission's discretion.

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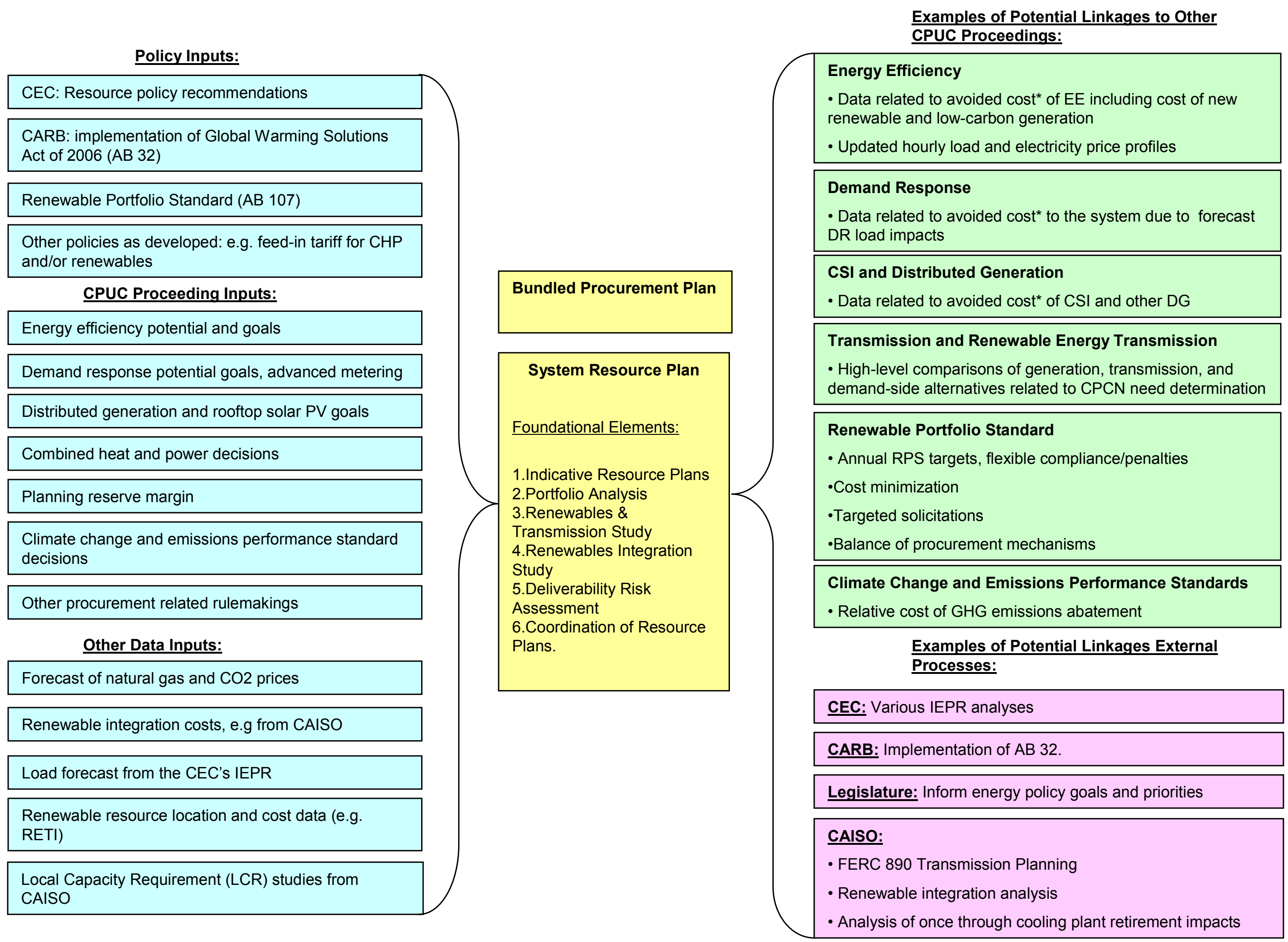
[150] D.07-12-052, at p. 6.



* The term "avoided cost" is used loosely in this context and is not intended to replace specific definitions of the term in various preferred resource proceedings

Figure 10. Potential inputs to, and outputs from, the LTPP proceeding.[151]

[151] Most of the input linkages, and *all* of the output linkages, represented in this chart are hypothetical at this point, and would require changes to current program administration and/or legislation. Exceptions include inputs such as the CEC load forecast, Commission-adopted EE goals, etc.

5.1 Potential Linkages to Commission Proceedings

The Proposed Planning Standards would enable the Commission to view the results of the Commission resource policies, aggregated across the IOUs' System Plans, and to evaluate them based on the cumulative, combined impact of these decisions on CPUC-jurisdictional ratepayers and the CPUC system more broadly. With these Planning Standards in place, the Commission would have an opportunity to gain insights from the System Plan to inform future procurement and resource policy decisions. Thus, staff sees the System Plan as a mechanism to facilitate a two-way flow of information, with specific inputs to the LTPP coming from resource proceedings and outputs from the LTPP feeding back to these proceedings.

There are a number of possibilities which the Commission could pursue in facilitating this two-way flow of information both into and out of the LTPP proceeding. One key area where the umbrella proceeding can help is in coordinating and informing cost-effectiveness determinations, which in turn, inform the goal and budget setting for the Commission's demand-side resource proceedings. The Proposed Planning Standards create a connection between the demand-side and supply-side resource decisions that was largely missing from previous LTPPs.

Other examples of important areas where the System Plan could facilitate coordination and inform goal-setting pertains to renewable energy procurement and the long-line transmission needs which may be required to access large quantities of renewable energy. Since demand-side resources affect the level and cost of renewable energy required to meet the RPS, it makes sense to consider the combined impacts of all of these policies together.

In general, each of the procurement-related proceedings at the Commission would inform the System Plan through inputs including demand-side program plans and RPS procurement plans (goals, budget forecasts). These proceedings could then be informed by the System Plan regarding a program's impact to the total system portfolio (avoided costs, carbon reductions, system average bill impacts). The outputs to each resource proceeding could vary from informational only, such as inputs to the proceeding's cost-effectiveness determinations, to more specific guidelines on budget and goals and other information useful in evaluating and informing program changes. Examples of how this iterative process of information could flow between the System Plan and the Commission's resource proceedings are presented below for EE, DR, CSI, RPS procurement, and transmission planning. Since there are differences in the informational needs, history and maturity of all of these proceedings, as well as the key decisions that must be made in each, the appropriate role of the System Plan would be different, as determined in the resource proceedings themselves.

5.1.1 Energy Efficiency (EE)

Energy efficiency is the largest and most sophisticated demand-side resource proceeding with the most substantial impact on customers' energy bills. The effects of EE programs have large interactive effects on the cost, delivery and financial risk of the supply-side portfolio. As such, there could be significant benefits in using the LTPP proceeding to inform the EE proceeding about what is truly being avoided at different target EE levels, and using the EE proceeding (and the CEC's IEPR process) to inform the LTPP proceeding about the amount of delivery risk associated with different target EE levels.

The EE proceeding develops its own goals and budgets through significant effort in resource potential studies, program planning, as well as stakeholder collaboration. Avoided costs were developed in the Avoided Cost proceeding (R.04-04-025), which are used to determine EE cost-effectiveness and estimates of economic potential. Other demand-side resource proceedings rely on these avoided cost determinations, as well. The avoided costs are assumed to be the costs to own and operate gas-fired resources, plus other utility avoided costs such as transmission and distribution along with environmental adders. There are also IOU shareholder incentives (currently under review in R.09-01-019) which are tied to the goals and cost-effectiveness calculations. The program planning develops long-term targets, and approves specific plans in three year cycles including the most recent 2009-2011 cycle currently being deliberated in R. 06-04-010.

Potential Inputs to LTPP Proceeding

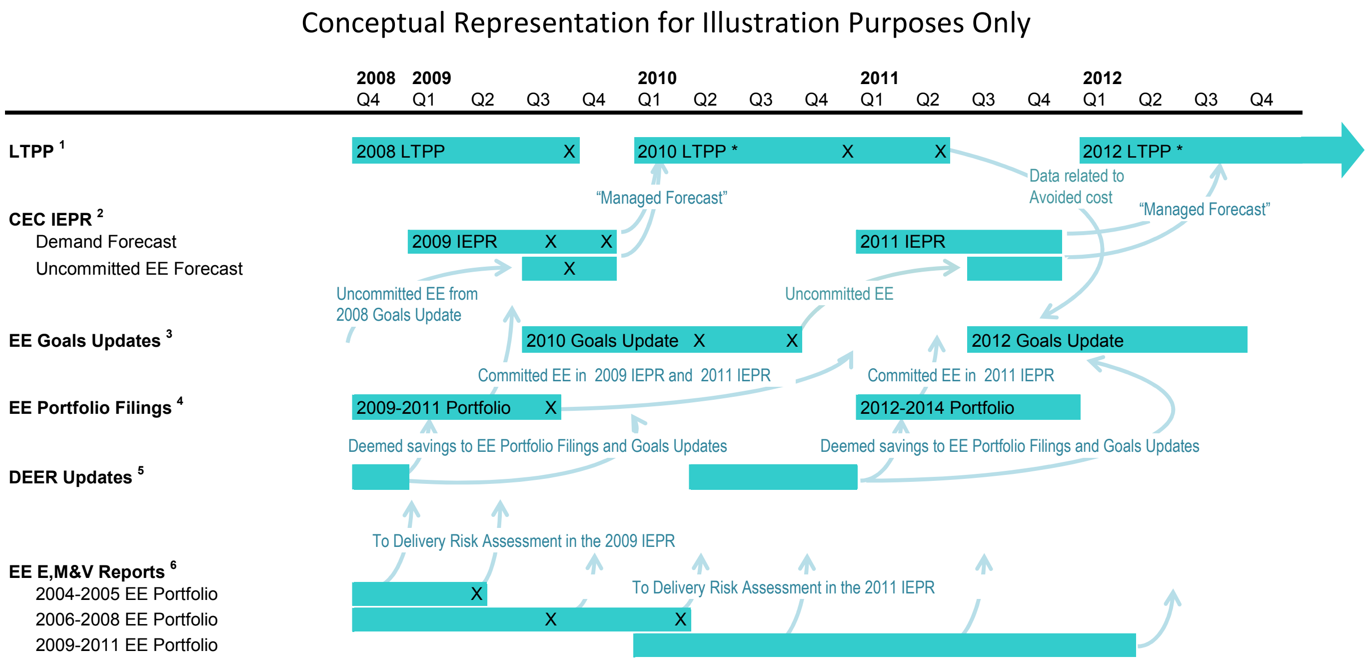
- The program plan such as EE impact goals (MWh load shapes and peak MW reductions) by service territory and combined budgets (See proposed assumptions in Section 3.8.1);

- The avoided distribution costs deliberated in the Avoided Cost proceeding;[152]
- An assessment of the appropriate level of EE impacts to guide both reliability evaluation for both transmission and generation planning and the delivery risk for the entire portfolio,
- Information about how costs and delivery risk change with different program goal levels, if available.

As previously mentioned in Section 3.8.1, an initiative is underway in the IEPR process to coordinate load forecast and EE inputs to the LTPP proceeding. Figure 11 below attempts to map out how the coordination of these inputs and outputs could conceivably occur over the next three years. The CEC's 2009 IEPR process is producing so-called "uncommitted EE forecasts" to interpret the expected incremental impacts on the load forecast of the Commission's interim TMG energy savings goals (and an even higher EE scenario analyzed in the Itron Goals Update Study). The IEPR process necessarily employs a Deliverability Risk Assessment, which relies in part on data from Evaluation, Measurement, and Verification ("EM&V") reports of utility EE programs, as well as other data, such as deemed savings estimates periodically updated in the Database on Energy Efficiency Resources.[153] When combined with the uncommitted EE forecast, the CEC's demand forecast can be considered a "managed forecast" because it accounts for the impacts of incremental, policy-driven measures to reduce demand. In the LTPP's system analysis, residual net short position is calculated based off the managed forecast.

[152] Avoided distribution costs were last updated in 2005 in R.04-04-025. The Commission may want to consider updated estimates for LTPP analysis purposes.

[153] www.energy.ca.gov/deer/.



Notes:
"X" depicts a milestone, such as a filing deadline, proposed decision, final decision, draft report, or final report, etc.
* Chart assumes the consecutive model for sequencing system and bundled analyses. For discussion, see Section 3.3.2.

1 Represented timeframes for the current and future LTPP proceedings are staff approximations, subject to change by the Commission.

2 Represented timeframes for 2009 IEPR milestones are approximate based on CEC Staff presentations at May 21, 2009 IEPR Staff Workshop on Energy Efficiency Measurement and Attribution and Preliminary Peak Forecast. Staff assumes the same process and schedule for the 2011 IEPR.

3 Like the 2008 process which relied on the Itron Goals Update Study, the 2010 Goals Update process would likely utilize a similar scenario analysis of resource potential to consider new goals. Staff assumes the same schedule for the 2010 and 2012 Goals Updates, as occurred in the 2008 process, subject to change by the Commission.

4 Represented timeframes for the 2009-2011 EE portfolio filing are based on the schedule set forth in the November 25, 2008 ACR/Scoping Memo in A.08-07-021 and related matters. Staff assumes the same schedule for the 2012-2014 portfolio filing, subject to change by the Commission.

5 The Database on Energy Efficiency Resources (DEER), jointly sponsored by CEC and CPUC, provides estimates of energy and peak demand savings values, measure costs, and effective useful life. It is periodically updated, as a source for deemed savings and measure cost data for CPUC's EE program planning.

6 Represented timeframes for E,M&V reports on the 2006-2008 EE portfolio are based on D.07-09-043, Attachment 6; January 11, 2006 ALJ Ruling in R.01-08-028, at p. 3; and actual experience.

Figure 11. Hypothetical inputs and outputs related to coordination of LTPP, IEPR load forecast, and EE proceedings.

Potential Outputs from LTPP Proceeding

- Guidance on the limits of what might be an acceptable level of EE delivery risk in the aggregate resource portfolio;
- Avoided costs of energy and avoided costs of local and system capacity associated with the forecast EE program level(s).
- Load shapes of energy production from the System Plan for use in updating avoided cost calculators.

Unlike the current avoided costs used by EE, which are linked to the theoretical cost of owning and operating gas fired resources, the LTPP proceeding could provide data inputs to avoided costs updates based on forecast changes to the actual (indicative) resource plan. This would allow, for example, the avoided costs of renewable energy purchases to be included in the estimate. Energy efficiency achievements reduce required renewable purchases under the current RPS legislation, since the RPS goal is benchmarked against retail sales. As estimated in a recent paper by Mahone et al. (2009), the "RPS-dependent avoided cost" of EE is 21% higher under a 33% RPS than a 20% RPS. [154] To produce their estimates the authors used data from E3's GHG Calculator and a supply-curve methodology, represented in Figure 12.

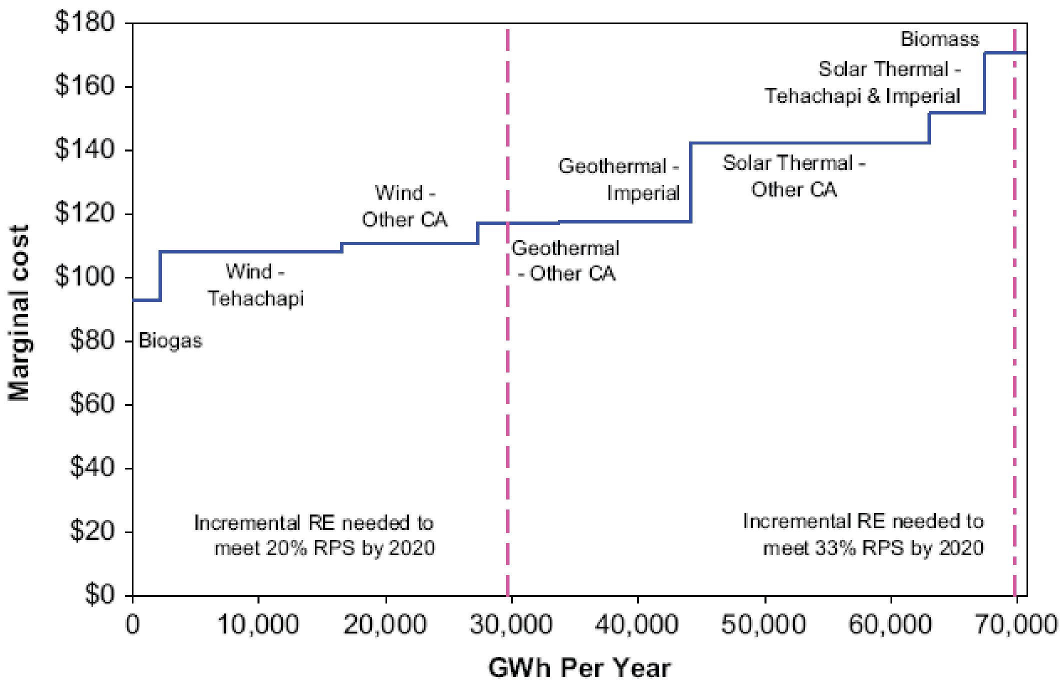


Figure 12. Supply curve for new renewables to meet California's 20% RPS and proposed 33% RPS target by 2020 (Source: Mahone et al. (2009))

The LTPP proceeding can also provide guidelines on other aspects of the EE portfolio design. For example:

[154] See Mahone, Woo, Williams and Horowitz. (2009). "Renewable portfolio standards and cost-effective energy-efficiency investment," *Energy Policy*, Vol. 37, Issue 3, March 2009.

- The minimum achievements required to meet the planned reliability targets might inform the shareholder incentive thresholds.
- Guidelines on the quantities of additional EE by time period that is desirable. For example, significant demand-side resources in combination with significant solar resources could decrease the value of incremental on-peak EE savings due to excess generation from solar resources.

5.1.2 Demand Response

The DR proceeding has a less established process and history in determining achievable potential and cost-effectiveness than the EE proceeding. In particular, the state goal of 5% price-responsive DR was established in the Energy Action Plan, but this goal has not yet been vetted through cost-effectiveness analysis or resource potential studies.

Potential Inputs to LTPP Proceeding

- Current DR program 2009-2011 plans (including forecasted MW and budgets) as well as other programs/tariffs authorized in other DR proceedings (See proposed assumptions in Section 3.8.1);
- Potential studies for DR would also be helpful inputs, if available.[155]
- Forecasted impacts of AMI on DR program delivery.

Potential Outputs from LTPP Proceeding

A large portion of DR's value lies in its ability to contribute to system reliability, which would be considered as part of the System Plan. Another important benefit of DR is its ability to increase the responsiveness of the system to increased penetration of intermittent renewable resources such as wind. These impacts can only really be assessed however in the context of a system-wide Portfolio Analysis. Therefore, DR-related proceedings could potentially benefit from the following outputs from the LTPP proceeding:

- Estimates of the savings from DR under reference case and sensitivity case assumptions;
- Forecasted avoided costs of DR to the system due to load shifting or peak clipping.

[155] For example, SDG&E recently commissioned a California DR potential study, but the results have yet to be released.

Like the EE proceeding, the DR proceeding would still determine the program goals, program design elements, and adopt 3-year utility program plans and DR budgets.

5.1.3 Customer-Side Distributed Generation, including California Solar Initiative

The Commission has programs to support DG on both the "customer-side of the meter" (i.e., on-site load reduction) and "utility-side of the meter"(i.e., on-site generation for export and sale through wholesale procurement). The distinction is important because resource planning models these resources differently depending on whether they reduce load or generate supply. Two well-known programs for facilitating use of on-site DG are the incentive programs, CSI and the Self-Generation Incentive Program (SGIP"). Because wholesale DG is a supply resource managed within the RPS program is it treated in Section 5.1.4.

For purposes of this report staff uses CSI as the primary example of customer-side DG. The CSI program has some significant differences from EE and DR. Although EE and DR have technology development components, market transformation is a primary goal of CSI. Also, the core program design is already established, along with funding through 2016. Another important distinction is that CSI goals and funding levels are mandated by statute, which gives the Commission less flexibility to determine the size of the program relative to other preferred resources.

Potential Inputs to LTPP Proceeding

- CSI program plan (allocation of installed capacity by utility, and budgets).
- Ranges of future price projections for on-site solar PV based on current PV system prices, as well as a range of publicly available price forecasts.

Potential Outputs from LTPP Proceeding

- Data for the cost-effectiveness calculation that would be completed in the CSI proceeding
- The rate impact forecast could help the CSI program adjust incentive payments in the program, and estimate installed system costs necessary to reach retail price parity;
- Estimates of the value of energy delivered to the grid through the net-energy metering program for evaluating the costs and benefits of net metering.

5.1.4 Renewable Portfolio Standards and Renewable Energy Procurement

The IOU system resource plans could provide important information to help guide renewable resource procurement policies. The State's 33% RPS policy goal has received support from the Governor as well as the State energy agencies, but has yet to become law. A high degree of uncertainty remains regarding how 33% RPS might be implemented in California.

One such tradeoff is whether and to what extent IOUs should procure out-of-state resources (whether from delivered renewable energy or through RECs) and whether the CPUC should encourage emerging technologies through a budget, capacity set-aside, or some other mechanism. Robust portfolio analysis in IOU system resource plans can help to provide insight into some of these questions, as well as the costs and benefits of integrating renewables into the grid. The LTPP, as the CPUC's umbrella proceeding, is a logical forum to weigh trade-offs between different procurement strategies in the context of the entire resource portfolio.

Potential Inputs to the LTPP Proceeding

A critical input to the LTPP proceeding will be renewable energy potential, renewable technology performance characteristics, and forecasts of renewable technology costs by region. As discussed in more detail in Section 3.2.3, creating useful IOU system resource plans will require regionally-differentiated resource data in order to optimize transmission location and assess transmission costs, regulatory feasibility (i.e., environmental consideration) of renewable resource development, and timelines required to interconnect renewable resources. The CPUC can offer some valuable inputs into the IOU system resource plans.

- Energy Division's 33% RPS Implementation Analysis can supply renewable energy resource characteristics. This effort built on RETI to include additional renewable resources in the Western Electricity Coordinating Council (WECC) domain. The analysis also provides a methodology for creating timelines for generation and transmission development.
- Actual RPS contract data are a potential source for supplementary renewable resource and performance data. Nonetheless, contract information will diverge from the cost and resource potential estimates compiled in any planning level effort, such as RETI. To the extent that this information can be used in the IOU system resource plans, it will help match the plans to the path that the State has already started down.

Other organizations can provide additional helpful information.

- RETI supplies renewable energy resource data, including cost, resource availability in and around California, resource characteristics, and environmental impacts. RETI also provides a conceptual transmission plan for the State to reach new renewable capacity.
- The WECC Transmission Expansion Planning Policy Committee (TEPPC) database can provide information on both renewable and fossil resources that are both already in place and planned.
- The National Renewable Energy Laboratory offers maps of renewable energy resource potential throughout the WECC region.

Renewable resource data are changing continuously, so data from any of these sources may need to be updated before being incorporated into the IOU system resource plans, depending upon how recently the data were collected and published.

Potential Outputs from the LTPP Proceeding

The IOU system resource plans could provide important information to inform renewable resource procurement policies. Examples of useful output data may include:

- The location (e.g. by renewable energy zone or REZ) of high-quality renewable resources in California and neighboring states
- The cost of developing those resources relative to alternatives (i.e. a renewable supply curve)
- The potential transmission needs for delivering renewable resources to load for a given location
- The cost, type, and quantity of dispatchable resources that would be needed to integrate the renewables and maintain system reliability
- The risk factors affecting whether the projects in a REZ would fail or be delayed (e.g. regulatory and market conditions)
- The timelines on which these generation and transmission resources would likely be developed (by REZ)

While the LTPP proceeding would not make any specific findings that would be binding on RPS proceedings, the IOU system resource plans could provide these (or some combination of these) outputs to (1) inform the public, policymakers, and other state agencies and/or (2) inform the RPS procurement plans.

Potential Use of LTPP Outputs to Inform the Public and Policymakers

The output from the IOU system resource plans could be used, similar to the *Preliminary 33% RPS Report*, to inform the public, policymakers, and state agencies on significant RPS issues, trends, and forecasts. Academics, non-profit organizations, and developers could use the information to inform new ideas for legislation or research and development to promote renewable energy in the State. Further, such detailed data about the progress and barriers facing renewable energy development would be useful to CARB, the CEC, and the CAISO to review their policies and processes.

Potential Use of LTPP Outputs to Inform RPS Procurement Plans

The output from the IOU system resource plans could alternatively (or additionally) be used to inform decisions about utilities procurement plans and/or RPS program rules. The data could be incorporated into utilities' annual RPS plans to make them more robust, consistent across utilities, and useful to develop sound implementation policies for the RPS program. The LTTP outputs could be used to inform:

- Flexible compliance/penalty assessment
- Targeted solicitations
- Cost minimization (least-cost procurement strategies)
- Balance of procurement mechanisms
- Annual RPS targets

The role that the IOU system resource plans could play in the RPS procurement plans depends on whether the State continues with the current 20% RPS by 2010 mandate, and the rules and legislation that delineate it, or whether a 33% RPS by 2020 becomes law and includes changes to the program structure. For the 20% RPS, the Commission could use the LTPP outputs to inform the IOUs' requests to use flexible compliance provisions, to assess penalties, to inform what type of targeted solicitations and/or procurement methods would be useful to expedite reaching the RPS targets at least cost. Going forward, the Commission would continue to use the LTPP outputs for the same purposes, but could additionally use the output to inform annual RPS targets, if future RPS legislation allows the CPUC to determine targets based on realistic generation and transmission timelines.

Flexible Compliance

Currently, RPS flexible compliance rules allow a utility to defer a portion of its RPS target for up to three years upon a convincing showing of insufficient transmission, seller non-performance, or lack of effective competition in an RPS solicitation[156]. However, it is not clear at this time whether the Commission has sufficient information to verify whether an IOU's filing requesting flexible compliance is reasonable. The output from the IOU system resource plans (e.g. project development timelines, cost, transmission needs, and risk factors) could be used as a benchmark against which a utility's justification for RPS deficits can be assessed.

Targeted Solicitations

The LTPP output could be used to identify, for the 20% RPS requirement and potentially for a 33% RPS target, whether the Commission should authorize solicitations targeting particular RPS resources. Such authorizations would be made through the RPS procurement plan. Targeted solicitations may be desired if the LTPP output shows that procuring particular resources would help IOUs to reach RPS obligations quicker or at a lower cost. Also, large ratepayer investments in new transmission lines that access specific resource areas may justify targeted RPS solicitations in order to fully subscribe a new transmission line and to reap the most benefit from ratepayers' investment. Further, the Commission could require utilities to hold solicitations for resources that can provide specific energy characteristics, such as being dispatchable or providing energy on-peak, that fit a utility's load profile.

Because the potential benefits of a targeted solicitation could be outweighed by developers' efforts at market manipulation, the CPUC could direct the utilities to operate the targeted solicitations in a manner that mitigates market manipulation and minimizes cost to ratepayers.

Cost Minimization

The RPS program requires utilities to rank RPS bids on a least-cost best-fit basis, in order shortlist the most cost-effective RPS resources bid into an RPS solicitation. This bid evaluation process is largely based on a specific bid's price and project viability, rather than an overall assessment of what RPS procurement strategy is desirable for an IOU. Each procurement

[156] There are additional justifications for flexible compliance. For more details, see CPUC D.09-06-018 available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/102099.doc.

strategy (e.g. in-state solar thermal, out-of-state wind, rooftop solar PV) has a different cost, risk and timing profile and will result in reaching an RPS target at a different time and at a different cost. A more robust procurement strategy could be achieved by requiring cost minimization strategies in a utility's procurement plan.

The Commission could use the renewable resource location and cost data, combined with the risk profiles and timelines, in the IOU system resource plans' to prioritize utility procurement of RPS resources. This prioritization could take into account the relative trade-offs of the resources. As a result, the Commission could approve cost minimization strategies that would give the utilities, CPUC staff, and stakeholders more guidance about which resources fit a utility's portfolio and are consistent with the State's policy goals.

Balance of Procurement Mechanisms

There are currently four main methods of renewable energy procurement: utility RPS solicitations, bilateral contracts[157], feed-in tariff (FIT), or utility-owned generation (UOG). Most of the 20% RPS program has been based on RPS solicitations, but the other procurement options are now being utilized more frequently. The Commission will increasingly need to balance the amount of procurement authorized for RPS solicitations with the quantity of other forms of renewable procurement. For example, the State is expecting large growth in utility-owned generation following the recent approval of Southern California Edison's Solar Roof Program that includes 500 MW of new solar photovoltaic (PV) capacity on commercial rooftops[158].

It is currently unclear what are the costs, risk and timing of each procurement method. However, using the output from the IOU system resource plans, the utilities could propose how much of each procurement method they plan to utilize to reach their 20%, and potentially 33%, RPS requirements. Then, the CPUC could authorize how much renewable capacity each IOU should solicit from each type of procurement mechanism based on the costs, risks, and timing of project development associated with each mechanism.

Annual RPS Targets

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[157] A bilateral contract is initiated and negotiated independently of an RPS solicitation.

[158] More information is available at http://docs.cpuc.ca.gov/Published/News_release/102580.htm.

The 20% RPS statute requires a utility to incrementally procure 1% more renewable energy each year, and to reach 20% RPS in 2010. However, the CPUC and other parties have realized that legislatively-mandated annual RPS targets may be unrealistic because renewable energy projects do not come online in a linear fashion. Rather, market and regulatory conditions affect a developer's ability to get a project built. In particular, new transmission lines are often needed to connect new projects to the grid, so utilities can't ensure that a given amount of new generation comes online annually.

If future RPS legislation provides flexibility for the CPUC to set annual RPS targets individually for each utility, the targets could be based on the reasonable timelines for developing proposed renewable facilities and transmission projects as well as based on an IOU's cost minimization strategy. The IOU system resource plans could provide this information for use in utilities' annual RPS plans.

5.1.5 Transmission Needs Determination

The efficient processing of transmission need determination is another area that could benefit from the broad and long-term view of planning that staff is recommending be used in the LTPP proceeding. Since the environmental impact of any specific route needs to be studied at a level of detail that is substantially beyond the scope of the LTPP process (i.e., CEQA), staff is not recommending that the LTPP decision be determinative of transmission need. Instead, the LTPP decision could be an important first step and the beginning of the transmission need determination process.

If the LTPP decision were to make appropriate findings with respect to methodology, data and assumptions to be used for the evaluation of transmission need (but not with regard to the prospective projects themselves), this could further streamline and facilitate CPCN applications. Because the CAISO is ultimately responsible for planning the transmission projects that IOUs would bring before the Commission for review, effective implementation of this strategy would require close coordination with the CAISO.

As part of its ongoing efforts to streamline the transmission planning and permitting process, the Commission gives a rebuttable presumption to the CAISO's economic analysis of transmission projects that are proposed on the basis of economics if the analysis meets the criteria in D.06-11-

018. The Commission is mandated under Pub. Util. Code § 1002.3, however, when evaluating any proposed transmission project, to "consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation…and other demand reduction resources";[159] any reliance on an CAISO's economic analysis must still satisfy this requirement.

The CAISO's economic analysis, the analysis performed within the CAISO's long-term Annual Transmission Planning Process ("TPP") defined under FERC Order 890, and the Commission's determination of need all rely on assumptions regarding the availability and cost of generation resources – topics that are debated and litigated heavily in the LTPP. As stated in the OIR, the LTPP process will "serve as the forum for comparing resource alternatives against each other, in terms of uniform criteria such as cost, risk, reliability, and environmental impact, in order to optimize California's electric resource portfolio".[160] Leveraging this LTPP analysis in the consideration of individual transmission cases – making use of the LTPP's comparison of resource alternatives and that proceeding's conclusions – could streamline the Commission's determination of need. Strengthening this coordination of inputs and assumptions with the CAISO's transmission development process and its economic assessment of individual lines could serve to:

- reduce the amount of time involved in planning transmission projects and preparing applications for Commission review;
- ensure full and consistent compliance with Pub. Util. Code § 1002.3;
- streamline the review of and reduce the litigation risk associated with the determination of need for new transmission projects, by providing consistent, transparent, and well-vetted resource assumptions;
- ensure that procurement actions authorized by the Commission in the LTPP reflect transmission development authorized in CPCN processes, and vice versa;
- promote transmission development that is consistent with state policies and priorities, and that facilitates the achievement of California's clean energy goals.

[159] Added by Stats. 2005, Ch. 366, Sec. 5.

[160] *R.08-02-007 OIR*, at p. 8.

The LTPP decision could either contain sufficient information to be used as a "cookbook" for subsequent planning and permitting, or it could embed its recommended methodology, data and scenarios in a "transmission calculator" that can produce net benefits from a combination of lines and resources selected. This second approach is similar to the "E3 Calculator" that is currently used by the three IOUs to calculate the net benefits of their EE programs or the "GHG calculator" that has also been used by a number of parties to estimate compliance costs associated with GHG targets in California's electricity sector. Both of these tools have reduced the time and effort required by both applicants and third parties to perform economic evaluation consistent with Commission-approved data and methodology.

In either case – the "cookbook" or the "calculator" – the data and tools approved by the LTPP decision would be designed to facilitate the CPCN applicants' participation in the CAISO's TPP. The TPP is conducted in three stages, over approximately 18 months:

1. Development of Unified Planning Assumptions and Study Plans
2. Technical studies
3. Documentation of technical study results and development of Transmission Plan

In Stage 1, the CAISO produces a Final Study Plan, the current version being the *2010 TPP Final Study Plan*.[161] The Final Study Plan results in the development of Unified Planning Assumptions to be used in all technical studies – reliability assessments, economic planning studies, etc. – conducted as part of the planning cycle. Technical studies provide the basis for identifying physical and economic grid limitations and potential upgrades for reliability, economic efficiency, or other policy objectives.

In order to complete the technical studies that form Stage 2 of the TPP, the CAISO must forecast future grid conditions. For example, Economic Planning Studies include an estimation of congestion over a 10-year planning horizon simulation. Thus, the CAISO must consider a variety of policy initiatives and other conditions that will have an affect on future grid configuration and constraints.

[161] See *2010 ISO Transmission Plan: Final Study Plan,* www.caiso.com/2374/2374ed1b83d0.pdf.

It is this need to model future grid conditions through a set of Unified Planning Assumptions that motivates the CAISO's intention to use renewables scenarios developed by the IOUs in the LTPP process, as noted in the *2010 TPP Final Study Plan*:

> Accordingly, the ISO intends to conduct a more detailed analysis, using the planning assumptions outlined in this Study Plan and the RETI Phase 2 conceptual transmission design, **along with renewables scenarios developed for the California Public Utilities Commission in its current long-term procurement proceeding**, to identify the need for specific transmission upgrades that will enable California LSEs to meet the 33% RPS goals. The results of this analysis will provide the information necessary for interested parties to propose specific projects through the 2009 Request Window for review in the 2010 Transmission Plan.[162]

To the extent that the renewables scenarios from the LTPPs form a part of the Unified Planning Assumptions for transmission planning, the transmission needs identified by the TPP will be consistent with the generation needs identified in the LTPP, resulting (theoretically) in the filing of applications at the Commission for individual projects that serve the demonstrated needs of the large IOUs.

Potential Inputs to LTPP Proceeding

- Renewable resource potential data, e.g. from source like RETI, existing transmission plans;
- WECC-wide long term forecasts of energy, local, and system capacity values;
- CEC load forecasts;
- EE, DR and DG potential and targets by area or zone;
- Gas prices by location;
- Standard transmission cost assumptions.

Potential Outputs from LTPP Proceeding

- Standardized load and resource tables by scenario;

[162] Id, at p.37 (emphasis added)

- Standardized assumptions about impact of demand side management, EE, DG, AMI, etc. on load forecast for each area or zone;
- Specific guidance on implementing the TEAM methodology for different types of projects (e.g., reliability, energy, RPS procurement);
- Sufficient variation in scenarios to be used for uncertainty analysis in each CPCN application.

5.2 Potential Linkages to External Processes

The recommended approach towards creating a System Plan in the LTPP will help facilitate coordination among the CPUC, CEC, CAISO, CARB and state agencies. For example, the resource portfolios developed for the LTPP could be used as data inputs into the CEC's IEPR or its statewide transmission corridor designation process. They could also be used by the CAISO's transmission planning process, as discussed above in Section 5.1.5, and other CAISO studies such as the 33% RPS integration study and grid reliability studies related to OTC policy. Estimates of the GHG profiles of various resource portfolios, combined with the total cost estimates of each portfolio, could provide CARB with up-to-date information about the relative cost of emissions abatement opportunities in the electricity sector, helping inform its implementation of AB 32.

6 Conclusion

By way of the EAP loading order, GHG policies, renewable energy mandates, OTC policies, and other aggressive energy policies, California continues to be a pacesetter for the nation and the world on efforts to combat climate change, increase resource diversity, reduce environmental impacts, and transform energy technologies. Achieving these goals will require careful planning and a substantial degree of coordination among the multiple entities with responsibility for various aspects of electric service. In the LTPP proceeding, California has taken deliberate steps to reinforce a long-term perspective in California's resource procurement decisions through adherence to the EAP loading order. However, opportunities for enhanced coordination still exist when implementing the loading order.

In past LTPP cycles, IOUs developed resource procurement plans independently from each other, despite the fact that high-quality renewable resources exist only in certain areas of the state. By requiring more geographic- and resource-specificity of data in the LTPPs, these plans would be more useful and better coordinated with the transmission planning studies conducted by the CAISO. The same type of detailed information is necessary to identify requirements for flexible fossil and other resource to reliably integrate increased levels of intermittent renewables. Similarly, determination of need for local area resources, particularly due to OTC policy-driven retirements, must rely on detailed planning information. At present, targets for acquisition of preferred resources are set in many individual forums that are implicitly coordinated with each other through the loading order policy. This pattern of decentralization in separate proceedings is chiefly one of administrative necessity; however, there is a need, at least periodically, to bring all of the resources and policies together to be considered in a comprehensive way.

This Energy Division Straw Proposal recommends the next step: California's three major CPUC-jurisdictional electric utilities – PG&E, SCE and SDG&E – should engage in coordinated, in-depth, system planning analyses in order to achieve multiple procurement-related policy goals through an integrated portfolio approach in the 2010 LTPP, and going forward. This effort would integrate all of the Commission's resource-related proceedings and produce Commission-preferred plans for providing reliable, cost-effective service to CPUC-jurisdictional loads, while striving to meet California's aggressive policy targets.

Appendix A. Quick Reference Guide on Principles for a Revamped LTPP

Table 13. Guiding Principles and Working Principles for a revamped LTPP.

<u>Guiding Principles</u>

1. Ensure reliability

2. Ensure the lowest reasonable rates

3. Comply with the EAP loading order

4. Anticipate AB 32 constraints on IOU electricity portfolios

<u>Working principles</u>

A. Resource plans should take a realistic view of expected policy-driven resource achievements in order to ensure reliability and track progress toward goals

B. Resource plans should be compatible with the Commission's goal of advancing markets

C. Resource plans should be comparable and informative

D. The Commission should use common assumptions and consistent methodologies across all resource-related proceedings

E. Resource plans should be informed by an open and transparent process

F. Resource plans should consider whether substantial new investments in transmission and flexible fossil generation would be needed to integrate and deliver new resources to loads

Appendix B. Staff Summary of May 14, 2008 *Joint-IOU Report* on Planning Standards

Pursuant to the May 7, 2008 *Administrative Law Judge's Ruling Clarifying Workshop Schedule On May 21, 2008 For Planning Standards and GHG Program Inventory*, on May 14, 2008 PG&E issued to the service list a pre-workshop report and accompanying Appendices A-C. The pre-workshop report, entitled *Pre-Workshop Report on Standardized Resource Planning Assumptions and Analytical Techniques for the 2010 Long-Term Procurement Plan* (*Joint-IOU Report*), was issued on behalf of PG&E, SCE, and SDG&E as a summary of work accomplished to date in the Planning Standards Working Group.[163] Table 11 below contains a staff summary of the salient points of agreement reached in the *Joint-IOU Report*.

Table 14. Staff summary of May 14, 2008 *Joint-IOU Report*

Item	Page Ref.	Description
Input Assumptions (Refer to bundled analyses, unless otherwise specified)		
Load Forecast (System & Bundled)	4	Updated IEPR load forecast will be used by all three utilities in the 2010 LTPPs for a "Reference Case." Other load forecasts may be used for other planning scenarios. The CEC intends to develop high and low uncertainty ranges around the load forecast, based on a combination of historic forecast error, variations due to economic cycles, and temperature effects on the peak; and uncertainties associated with EE and CSI.
Energy efficiency (System & Bundled)	4	IEPR load forecast will specifically identify the amount of EE in its forecast, including separately identifying amounts of impact from committed and uncommitted EE programs.
Demand response (System & Bundled)	5	Amount of DR that is being used to reduce the utilities' respective loads will be clearly and specifically identified in the 2010 LTPPs.

[163] The Planning Standards Working Group was comprised of staff members of PG&E, SCE, SDG&E, Energy Division, and California Energy Commission (CEC).

Table 14. Staff summary of May 14, 2008 *Joint-IOU Report*

Item	Page Ref.	Description
Gas price forecasts	5	Gas price forecast methodology (not actual values) used in the MPR is suitable for use as the basis to forecast gas prices in the LTPP analysis.[164] The utilities will apply the MPR methodology using the same quote date, as specified in the 2010 LTPP scoping memo. Despite using the same gas price forecast methodology, it is expected that each utility will have different gas forecast values due to each utility's unique basis differentials.
Electricity price forecasts	5-6	Differences in load and resource computer modeling techniques among the three utilities will not permit the electricity price forecast methodology to be completely standardized. Differences are not a major concern provided that the forecasts are reasonable. The utilities should report the implied market heat rate to ensure that the relationship between the gas and electricity price forecasts is reasonable across the utilities.
New conventional Resource costs	6	Further discussions on this issue are necessary.
New Renewable Resource Costs	6	Determining the appropriate range for renewable costs will be challenging, and will require additional investigation.
Resource Additions/Retirements (System & Bundled)	7	A special methodology is not needed. For resource additions and retirement assumptions that are listed in the physical system capacity need tables [Appendix D], each utility should identify which additions (specifically) and retirements (in aggregate) are assumed in their respective plans and the criteria used to determine them. Generally agreed that Line 10 (Known/High Probability Additions) of the physical system capacity need table would contain resources that have a contract in place, have been permitted, and have construction well under way. Criteria for resources in Lines 11 and 12 (Other Utility Planned Additions NQC; and Other non-Utility Planned Additions NQC, respectively) would include resources that have a contract, but have not yet begun construction.

[164] As of May 14, 2008, when the Joint IOU Report was issued, the MPR methodology used a blend of forward market prices and fundamentals forecasts, but the methodology was under review in R.06-12-012.

Table 14. Staff summary of May 14, 2008 *Joint-IOU Report*

Item	Page Ref.	Description
Re-contracting rates	7	There is no need to standardize as each utility may have inherently different success rates that are unique to their region or other circumstances.
Standardized Formats (Refer to bundled analyses, unless otherwise specified)		
General	8	Given the voluminous amounts of data associated with various [bundled] scenarios and confidentiality concerns, data should generally be presented at the annual level, as compared to monthly. The only potential exception would be for a "Reference Case" scenario in which monthly data would be provided for only the first year or two of the 10-year planning horizon.
Loads & Resources Table for Physical System Needs (Capacity)	9	Standardized tables [Appendix C] shall be used to show the physical capacity needs for CAISO NP-26 and SP-26 regions, as well as the utility service areas. The utilities will also be free to include other tables that may better illustrate their respective circumstances and resource needs.
Loads & Resources Table for Bundled Needs (Energy & Capacity)	10	The utilities' bundled service customer capacity and energy need tables [Appendices C & D] will be modeled on the CEC's most current IEPR forms (S-1 and S-2), because it (1) creates consistency between the LTPP and IEPR processes; (2) permits easy comparisons across utilities; and (3) utilizes the CEC's well-developed line-by-line definitions. Capacity values will be based on adopted RA counting rules for Net Qualifying Capacity ("NQC"), not nameplate or other similar values. Because DR programs eliminate the need for reserves, it is more appropriate to show all the programs in one place and before the calculation of planning reserves. All capacity needs will have a negative sign, if the utility is short capacity to meet its total obligations.
Other Issues (Refer to bundled analyses)		
Portfolio Analysis	11	A balance needs to be achieved between the number of scenarios evaluated and the information needed to allow the utilities and the Commission to make informed decisions. Further discussions on this topic are necessary.
Metrics	11-12	Possible metric considerations may include: Reliability of Service (e.g., measures of unserved energy, loss of load probability and local area reliability); Cost of Service (e.g., total annual costs, resulting revenue requirements, average customer rates); Financial Risk (range of customer cost exposures due to load and market price volatility); and Environmental Performance (e.g., GHG total tons, GHG lbs/MWh,

Table 14. Staff summary of May 14, 2008 *Joint-IOU Report*

Item	Page Ref.	Description
		criteria pollutant emissions).
Inflation Rates	7-8	Consensus was to display costs in nominal terms. Consensus was to have a common, but presently undetermined inflation rate (index). Further discussions on this topic are necessary.

Appendix C. Loads and Resource Table for System Need: MW (*Joint-IOU Report*)

Table 15. Standardized loads and resources table for system need: MW

Utility Name
Physical North of Path 26 (NP26)/South of Path 26 (SP26) Capacity Need
Scenario: xx

Line*		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	**25,000**									
2	**Service Area** 1-in-2 Peak Summer Demand	**23,000**									
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
3	Uncommitted EE	300									
4	Net Qualifying Capacity (NQC) of Price Sensitive Demand Response (DR)	500									
5	NQC of Interruptible/Curtailable DR	400									
6	**Residual Service Area Peak Demand (Line 2 - Sum (Lines 3 thru Line 5)**	**21,800**									
	SYSTEM RESOURCES:										
7	Existing Generation NQC	25,000									
8	Retirements (Announced)	(100)									
9	Retirements (Assumed for this scenario)	(200)									
10	Known/High Probability Additions	100									
11	RPS Additions NQC (Including Imports)	100									
12	Other Utility Planned Additions NQC	300									
13	Other non-Utility Planned Additions NQC	100									
14	Net Interchange (Sum Lines 15 thru 17)	200									
15	*Non-Firm Imports (Require Reserves)*	*2,300*									
16	*Firm Imports (Do Not Require Reserves)*	*700*									
17	*Exports*	*(2,800)*									
18	**Total System Resources (Sum Lines 7 thru Line 14)**	**25,500**									
19	**Service Area Portion of System Resources (Line 18 * (Line 2/Line 1))**	**23,460**									
	SERVICE AREA PLANNING RESERVES:										
20	Available Planning Reserve - not adjusted for firm imports (Line 19 - Line 6)	1,660									
21	Available Planning Reserve (Percentage) (Line 20/Line 6)	7.6%									
22	Lower Bound of Planning Reserve Requirement (Line 6 * 15%)	3,270									
23	Upper Bound of Planning Reserve Requirement (Line 6 * 17%)	3,706									
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
24	Lower Bound 1-in-2 Service Area Surplus (Deficit), Adjusted for Firm Imports	(1,505)									
25	Upper Bound 1-in-2 Service Area Surplus (Deficit), Adjusted for Firm Imports	(1,927)									

*** See notes by line number on folowing page**

Appendix C Notes by Line Number:

1 System peak demand represents peak demand in CAISO's control area, North of Path 26 (NP26). This includes the PG&E service area and participating publicly owned utilities in the NP26 region served by the CAISO.

2 Service area peak demand represents the peak demand in the PG&E service area, independent of LSE providing service. Service area peak demand includes bundled and direct access (DA) customer peak demand, and excludes publicly owned utility (POU) peak.

7 Resources included here match the CEC's most recent resource assessment from [date and document source].

10 System Resource additions that meet predetermined criteria.

14 Sum of all imports and exports into service area.

19 Service Area Portion of System Resources = Total System Resources *(Service Area Demand/System Demand)

20 Available Planning Reserve = Service Area Resources - Service Area Demand (not adjusted to account for the difference between firm and non-firm imports)

21 Available Planning Reserve = Available Planning Reserve/Service Area Demand

22 Service Area Demand * 15%

23 Service Area Demand * 17%

24 Line 20 + (adjusted for firm imports by adding 15% of Line 16) - Line 22

25 Line 20 + (adjusted for firm imports by adding 17% of Line 16) - Line 23

Appendix D. Loads and Resource Table for Bundled Need: MW (*Joint-IOU Report*)

Table 16. Standardized loads and resources table for bundled need: MW

Electricity Resource Planning Form S-1
[Utility Name's] Capacity Resource Accounting Table
Bundled Customer Need - Scenario: xx

Line	IEPR Table Line		MW 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
		PEAK LSE LOAD CALCULATIONS:										
1	1	**Forecast Total Peak-Hour 1-in-2 Demand**	**10,000**									
2	2	CCA & Departing/Arriving-New Municipal Loads (-/+)	(100)									
3	3	Uncommitted Energy Efficiency (2012-2018) (-)	(100)									
4	4	Demand Response/Interruptible Programs (-)	(100)									
5	5	Self Generation (Total, Non-CSI) (-)	(100)									
6	6	California Solar Initiative (-)	(10)									
7	7	Direct Access Loads (-/+)	(1,000)									
8	8	*Subtotal: Adjustments to Peak-Hour Demand (Lines 2 thru 7)*	*(1,410)*									
9	9	**Adjusted Peak-Hour Demand for End-Use Customers (Sum Line 1 + Line 8)**	**8,590**									
10	10	Coincidence Adjustment (-)	(50)									
11	11	**Net Peak-Hour Demand (Sum Line 9 + Line 10)**	**8,540**									
12	12	Specified Planning Reserve Margin (such as 15%) **(Line 11 * 15%)**	1,281									
13	13	Firm Sales Obligations (+)	0									
14	14	**Firm LSE Peak-Hour Resource Requirement (Sum Lines 11 thru 13)**	**9,821**									
		EXISTING & PLANNED RESOURCES:										
15	15	LSE-Owned Fossil Resources	2,000									
16	16	LSE-Owned Nuclear Resources	1,000									
17	17	LSE-Owned Hydroelectric Resources (1 in 5)	1,000									
18	18	LSE-Owned Renewable Resources	100									
19	19	DWR Contractual Resources	1,000									
20	20	Qualifying Facility (QF) Contractual Resources	1,000									
21	21	Renewable Energy Contractual Resources	1,000									
22	22	Other Bilateral Contractual Resources	500									
23	23	**Total Existing and Planned Resources (Sum Lines 15 thru 22)**	**7,600**									
24	24	**(Resource Need) or Surplus (Line 23 - Line 14)**	**(2,221)**									
25	25	**Specified Planning Reserve Margin (Percentage)**	**15%**									

Appendix D (Cont'd). Loads and Resource Table for Bundled Need: GWh (Joint IOU Report)

Table 17. Standardized loads and resource table for bundled need: GWh

Electricity Resource Planning Form S-2
[Utility Name's] Energy Balance Resource Accounting Table
Bundled Customer Need - Scenario: xx

Line	IEPR Table Line		GWh 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
		PEAK LSE LOAD CALCULATIONS:										
1	1	**Forecast Total Energy Demand/Consumption**	**50,000**									
2	2	CCA & Departing/Arriving-New Municipal Loads (-/+)	(500)									
3	3	Uncommitted Energy Efficiency (2012-2018) (-)	(500)									
4	4	Demand Response/Interruptible Programs (-)	(500)									
5	5	Self Generation (Non-CSI) (-)	(500)									
6	6	California Solar Initiative (-)	(25)									
7	7	Direct Access Loads (-/+)	(5,000)									
8	8	*Subtotal: Adjustments to Energy Demand (Lines 2 thru 7)*	*(7,025)*									
9	9	**Adjusted Energy Demand/Consumption (Line 1 + Line 8)**	**42,975**									
10	10	Firm Sales Obligations (+)	0									
11	11	**Firm LSE Energy Requirement (Sum Lines 9 thru 10)**	**42,975**									
		EXISTING & PLANNED RESOURCES:										
12	12	LSE-Owned Fossil Resources	8,000									
13	13	LSE-Owned Nuclear Resources	8,000									
14	14	LSE-Owned Hydroelectric Resources (1 in 2)	1,000									
15	15	LSE-Owned Renewable Resources	1,000									
16	16	DWR Contractual Resources	1,000									
17	17	Qualifying Facility (QF) Contractual Resources	4,000									
18	18	Renewable Energy Contractual Resources	6,000									
19	19	Other Bilateral Contractual Resources	500									
20	20	Spot Market Purchases	2,500									
21	21	Short Term Sales (-)	(1,000)									
22	22	**Total Existing and Planned Resources (Sum Lines 12 thru 21)**	**31,000**									
23	23	**(Energy Need) or Surplus (Line 22 - Line 11)**	**(11,975)**									
		Generic Energy Resource Needs:										
24	24	Renewable Energy	3,000									
25	25	Non-Renewable Baseloaded Energy	6,000									
26	26	Non-Renewable Peaking Energy	2,975									
27	27	**Total Generic Energy Resource Needs**	**11,975**									

Appendix E. Proposed Guidelines for DR Load Impact Forecasting

Table 18. 2009-2011 DR programs to include in the DR load impact forecast for the 2010 LTPP.

DR Category	Utility	Program Name	LIP Categories [165]
Emergency	SCE	Agriculture & Pumping Interruptible, Base Interruptible Program, Optional Binding Mandatory Curtailment Program,* Scheduled Load Reduction Program, Summer Discount Plan	Event-based & Non-event based
	SDG&E	Base Interruptible Program, Summer Saver Program, Optional Binding Mandatory Curtailment Program,* Scheduled Load Reduction Program	
	PG&E	Base Interruptible Program, Optional Binding Mandatory Curtailment Program,* Scheduled Load Reduction Program, Smart AC	
Price Responsive	SCE	Capacity Bidding Program, Critical Peak Pricing, Demand Bidding Program, Energy Options Program, Real Time Pricing	
	SDG&E	Default Critical Peak Pricing, Emergency Critical Peak Pricing, Peak Time Rebate Program, Capacity Bidding Program	
	PG&E	Demand Bidding Program, Critical Peak Pricing, Capacity Bidding Program, Peak Choice, Department of Water Resources	
Aggregator Managed	SCE	Proposed Contracts	Event-based
	PG&E	Aggregator Managed Programs, Business Energy Coalition, Auto BEC	
Permanent /Seasonal Load Shifting	SCE	Automated Demand Response, Agriculture Pump Timer Program	Non-event based
	PG&E	Permanent Load Shifting	

* Program not counted for RA purposes

165 Commission-adopted Load Impact Protocols (LIPs) categorize utilities DR programs in two broad categories: (1) Event-Based and (2) Non-event Based resources. Event based resources (i.e., AC cycling) are DR programs that only operate when a specific DR event is called. Non-event based resources (i.e., Time-Of-Use rates or permanent load-shifting) operate daily, regardless of a DR event being called. See further details in Attachment A to D.08-04-050.

Appendix F: Glossary of Defined Terms

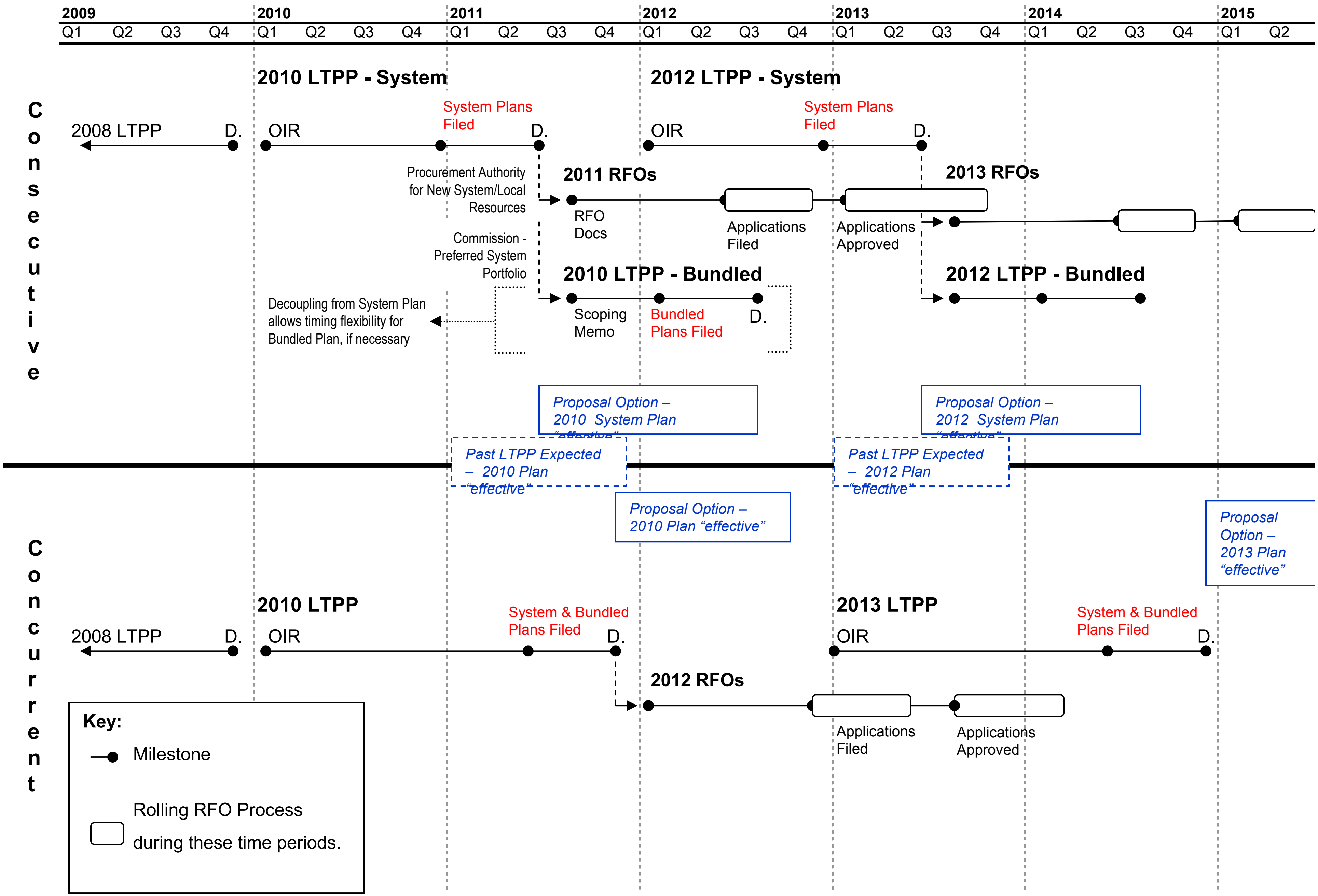
Aspen / E3	Energy Division consultants to the LTPP process: Aspen Environmental Group, Inc, (“Aspen”) and Energy and Environmental Economics, Inc. (“E3”)
Best Practices Report	Aspen/E3. (2008). *Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California: Final Report and Appendices*, July 2009.
bundled	Loads and resources of the IOU as a Load Serving Entity
Bundled Plan	Procurement plan to serve bundled load
Conceptual Transmission Link	A high-level approximation of a potential transmission project in the LTPP that is useful for investigating whether or not more detailed transmission engineering work is warranted; *not* a transmission project with a specific route or set of facilities that a utility has proposed or may propose to construct.
Coordinated System Plans	The baseline implementation alternative for conducting system analyses, implied by the Energy Division Straw Proposal; as opposed to the Joint System Plan alternative.
Coordination of Resource Planning	A Foundational Element encouraging use of consistent assumptions and methodologies (1) among IOUs LTPPs, and (2) across Commission proceedings and external process, as represented in the Commission-adopted Indicative Resource Plan.
Deliverability Risk Assessment	A Foundational Element requiring the IOUs to generate realistic expectations that a given resource or set of resources identified in an Indicative Resource Plan would be online and available to meet peak loads during any given year of the study period.
Foundational Elements	Basic requirements of the Energy Division Straw Proposal, drawn from Guiding Principles, and more refined Working Principles. These include: (1) Indicative Resource Plans; (2) Portfolio Analysis; (3) Renewables and Transmission Study; (4) Renewables Integration Study; (5) Deliverability Risk Assessment; and (6) Coordination of Resource Planning.
Guiding Principles	Overarching principles for the Commission's LTPP program oversight, as defined in the *R.08-02-007 OIR*, at p. 8.
indicative	In the context of a Commission-adopted Indicative Resource Plan, “indicative” means the detailed, resource- and location-specific data in the resource plan represents a reasonable forecast of a future resource mix, based on the Commission’s judgment of the best available information. Like any forecast, interpretation of the results is subject to change as the underlying assumptions and market conditions change over time. The term “indicative” is used in contrast to “prescriptive,” that implies that utility procurement is constrained by prescribed types, quantities, and locations of

	resources set forth in the approved plan.
Indicative Resource Plan	A Foundational Element requiring the IOUs to utilize detailed location- and resource-specific data to projected future resource mixes. Indicative Resource Plans are informational or illustrative only, and Commission adoption is expected to be binding only with regard to need for new resources to meet system and/or local RA requirements.
Joint System Plan	An implementation alternative to Coordinated System Plans that would require the IOUs to jointly develop and file System Plans.
Joint-IOU Report	May 14, 2008, *Pre-Workshop Report on Standardized Resource Planning Assumptions and Analytical Techniques for the 2010 Long-Term Procurement Plan*, issued on behalf of PG&E, SCE, and SDG&E as a summary of work accomplished to date in the Planning Standards Working Group.
Planning Standards	Standardized resource planning practices, assumptions and analytic techniques applied in long-term procurement plans, based on an integrated resource planning framework (as defined in *R.08-02-007 OIR*, at p. 10).
Portfolio Analysis	A Foundational Element requiring that the IOUs develop of least-cost best-fit portfolios under a variety of alternative future scenarios, using an optimized combination of demand- and supply-side and generation and transmission solutions.
Preliminary 33% RPS Report	CPUC. (2008). *33% Renewables Portfolio Standard: Preliminary Results*, June 2008.
Procurement Plans	Synonymous with Bundled Plans
Proposed Planning Standards	Energy Division proposals to fulfill OIR requirements for Planning Standards.
Renewables Integration Study	A Foundational Element requiring the IOUs to generate or utilize analyses to identify (1) the cost, type, and quantity of dispatchable resources that would be needed to integrate intermittent renewables and maintain system reliability, and (2) the resource options (e.g., storage, CTs, etc.) capable of satisfying operational needs.
Renewables & Transmission Study	A Foundational Element requiring the IOUs to conduct high-level assessments and prioritizations of renewable energy zones (REZ), including (1) the cost of developing those resources relative to alternatives (i.e., a renewable supply curve), (2) the Conceptual Transmission Links needed to deliver renewable resources to load for a given location, and (3) the risk factors affecting whether the projects in a REZ would fail or be delayed (e.g. regulatory and market conditions).
Resource Plans	Synonymous with System Plans
Scoping Memo	The August 28, 2008 Phase 1 Assigned Commissioner's Ruling and Scoping

	Memo
service area	An IOU's service territory inclusive of bundled, DA, and CCA customer load and exclusive of POU load, as defined in D.07-12-052, Tables PGE-1, SCE-1, and SDGE-1.
staff	CPUC Energy Division Staff
system	"System" refers, individually, to loads and resources within (or deliver to) an IOU's service area or, jointly, to the combined service areas of PG&E, SCE and SDG&E.
System Plan	The system portion of the Indicative Resource Plan that, when adopted by the Commission, provides IOUs with authorization to procure (build, contract for, or otherwise cause to be constructed) new resources to meet system and.or local RA requirements in their service areas.
Working Principles	More refined principles for Planning Standards, drawn from the OIR and other Commission decisions, as defined in Section 2.2. of the Energy Division Straw Proposal.

(END OF ATTACHMENT 2)

ATTACHMENT 3



Note: Assumed timeframes for consecutive and concurrent options are based on schedule estimates in Table 1 of the Energy Division Straw Proposal

ATTACHMENT 4

PRELIMINARY POST-WORKSHOP QUESTIONS

(Responses to be filed by August 21, 2009)

Energy Division Straw Proposal on LTPP Planning Standards ("the report")

The report establishes seven **working principles** representing the Commission's direction in various rulings and decisions pertaining to planning standard.

1. Are the working principles accurate representations of the Commission's direction? If not, why not?
2. Do you suggest any other working principles, based on the Commission's direction?

The report proposes six **foundational elements**, representing conclusions drawn from the working principles and OIR guiding principles.

3. Do you concur with the foundational element on **indicative resource plans**? Do you agree with staff's assessment that the benefits outweigh the risks? If not, why not?
4. Do you concur with the foundational element on **portfolio analysis**? Do you agree with staff's assessment that the benefits outweigh the risks? If not, why not?
5. Do you concur with the foundational element on a **renewables and transmission study**? Do you agree with staff's assessment that the benefits outweigh the risks? If not, why not?
6. Do you concur with the foundational element on a **renewables integration study**? Do you agree with staff's assessment that the benefits outweigh the risks?? If not, why not?
7. Do you concur with the foundational element on **delivery risk assessment**? Do you agree with staff's assessment that the benefits outweigh the risks? If not, why not?
8. Do you concur with the foundational element on **coordination of resource planning**? Do you agree with staff's assessment that the benefits outweigh the risks? If not, why not?

The report makes a distinction between system and bundled analysis in the LTPP, and describes two potential approaches to sequencing the analytics: consecutive or concurrent phases.

9. Do you prefer **consecutive or concurrent alternative**? Please describe the advantages and disadvantages of each alternative, whether the same or different from the ones identified by staff.

The report proposes specific planning standard. Do you concur with the specific proposals for each of the following items? If so, why? If not, what would you propose instead, and why?

10. **Resource planning process steps**, as described in Table 1. Based on the preferred alternative in Question #9 above:
    a. Do the process steps appear reasonable?
    b. Does the time allowed for each step appear feasible?
    c. Are there ways to combine steps or compress the time schedule, without unduly harming the quality of the stakeholder process?

11. Do you concur with the **definitions of**:
    a. “**scenario**?”
    b. “**portfolio**?”
    c. “**sensitivity**?”
12. Do you concur with the proposed **required scenarios for 2010 LTPP**:
    a. Natural gas-only scenario (for benchmarking proposes only)?
    b. CARB complimentary policies scenario?
    c. Least-cost renewables resource scenario (if different from the CARB scenario)?
    d. Transmission-constrained scenario?
    e. Nuclear retirements/OTC policy scenario?
13. Do you concur with the proposed **optional scenarios for 2010 LTPP**:
    a. Utility-preferred scenario?
    b. High vehicle electrification scenario?
    c. Very high gas and CO_2 price scenario?
    d. High in-state wind scenario?
    e. IGCC or new nuclear scenario?
    f. Market transformation scenario?
14. Do you concur that **reliability**, as measured by the planning reserve margin (PRM), should be treated **as a constraint**, not a variable metric, in the LTPP?
15. Do you concur with the proposed **metrics and assessments for System Plans**:
    a. Cost metric:
        i. Net present value of revenue requirement (utility cost)?
        ii. Total resource cost (customer and utility cost)?
        iii. Term of cost calculations?
    b. Risk metric:
        i. Robust scenario and sensitivity analysis?
    c. GHG Emissions metric:
        i. Total GHG emissions during each year of the planning horizon?
        ii. Average, per-ton cost of GHG emissions abatement?
    d. Environmental assessment?
    e. Resource development timeline?
    f. Long-term GHG reductions and technology transformation?
16. Do you concur with the proposed **metrics for Bundled Plans**:
    a. Cost:
        i. Net present value of revenue requirement (utility cost)?
    b. Risk:
        i. TEVaR?
        ii. Robust sensitivity analysis?

c. GHG Emissions:
    i. Total GHG emissions in starting year and 10 years out?

17. Do you concur with the proposed **required sensitivities** for System and Bundled Plans:
    a. Natural gas price?
    b. CO_2 price?
    c. Need level?
    d. Technology cost (System Plan only)?
18. Do you concur with the proposed standardized **loads and resources tables**:
    a. System (physical) need, MW (Appendix C)?
    b. Bundled need, MW (Appendix D)?
    c. Bundled need, GWh (Appendix D)?
19. Do you concur with the proposed base case inputs and assumptions on calculating **residual net short** for System and Bundled Plans?:
    a. Load growth?
    b. Energy efficiency?
    c. Demand response?
    d. Customer-side distributed generation, including California Solar Initiative?
    e. Wholesale distributed generation, including combined heat and power?
    f. Retirements/new resource additions?
    g. Re-contracting rates (Bundled Plan only)?
20. Do you concur with staff's recommendation to require the utilities to estimate an **error band on residual net short** for system need, as defined by high- and low-load sensitivities; estimate probability of occurrence to high-, low-, and "base case" and explain the rationale justifying the estimates?
21. Do you concur with the proposed inputs and assumptions on **new resource cost and performance assumptions**, in general, and in specific for the 2010 LTPP:
    a. Renewable resource availability, cost, and performance?
    b. Conventional and other resource cost and performance?
    c. New generation tax and financing assumptions?
    d. On-peak capacity?
    e. Transmission cost assumptions?
    f. Distribution cost assumptions?
22. Do you concur with the proposed inputs and assumptions on **market price forecasts**, in general, and in specific for the 2010 LTPP:
    a. Natural gas price?
    b. Biomass and coal prices?
    c. Electricity market price?
    d. CO_2 price?
    e. GHG policy assumptions?

23. Do you concur with the proposed methodology for **accompanying studies**:
    a. Deliverability risk assessment methodology, in general? (Comments on specific proposed mythologies for the 2010 LTPP are in response to Question #19.)
    b. Renewables and transmission study methodology, in general, and in specific for the 2010 LTPP?
    c. Renewables integration study methodology, in general, and in specific for the 2010 LTPP?
24. Do you concur with the proposed requirement on presentation of information?

The report describes an implementation alternative: **a Joint System Plan**. Although not part of the Staff Proposal, staff analyzed the approach in order to initiate dialogue among parties on the merits or risks of this approach.

25. Is the list of potential benefits comprehensive and well-reasoned? If not, what would you add, subtract or modify?
26. Is the list of potential costs and risk comprehensive and well-reasoned? If not, what would you, add subtract or modify?
27. Overall, do you find that potential benefits of the Joint System Plan alternative outweigh the potential cost and risks, or vice versa, and why? Do you recommend the Joint System Plan alternative?

Attachment 3 of the Amended Scoping memo presents timelines for completing all procurement related objectives that take place during LTPP proceedings, as well as the actual utility procurement activities that may result from the proceeding (e.g. conduct RFOs, file applications for new resources, etc.). The timelines in Attachment 3 correspond to the estimated schedule in Table 1 of the Staff Proposal.

28. Can your respective organization staff all the various ongoing pieces of the Procurement process as outlined the Staff Proposal? Please comment on both models.
29. Is it a reasonable expectation to have overlapping LTPP proceedings, such as in the consecutive model which would require simultaneous consideration of 2010 LTPP **Bundled Plans** and 2012 LTPP **System Plans** (unless 2010 LTPP **Bundled Plans** are decoupled and accelerated)?
30. Under the consecutive approach, **System Plans** would become effective upon issuance of a Commission decision approximately 5 months after the **System Plan** is filed and approximately 18 months after the OIR. Is this a reasonable approach? If not, why not?
31. Under the consecutive approach, **Bundled Plans** would become effective upon issuance of a Commission decision approximately 4 months after the **Bundled Plan** is filed and approximately 27 months after the OIR. i.e., 2010 bundled plans would become effective approximately Q3 2012 unless **Bundled Plans** are decoupled and accelerated). Is this a reasonable approach? If not, why not?

32. Under the concurrent approach, **System and Bundled** plans would become effective upon issuance of a Commission decision approximately 6 months after the **Combined Plans** are filed and approximately 23 months after the OIR. (i.e., 2010 **System & Bundled Plans** are effective Q4 2011.) Is this a reasonable approach? If not, why not?

(END OF ATTACHMENT 4)