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Attachment 1

Energy Division Proposal:
Standardized Load and Resource Tables for System Resource Plans

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**

Notes by Line Number:

1 System peak demand represents peak demand in CAISO's control area, North of Path 26 (NP26) or South of Path 26 (SP26). This includes the PG&E service area and participating publicly owned utilities i 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 have a contract in place, have been permitted, and have construction well under way.

12 System resource additions resources that have a contract, but have not yet begun construction.

13 System resource additions resources that have a contract, but have not yet begun construction.

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

San Diego Gas & Electric
Physical Capacity Need for SDG&E
Scenario: xx

Line*		MW									
	LOCAL RELIABILITY AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**Service Area** 1-in-2 Peak Summer Demand	**25,000**									
	LOCAL RELIABILITY AREA SPECIFIC LINE ADJUSTMENTS:										
2	Uncommitted EE	300									
3	Net Qualifying Capacity (NQC) of Price Sensitive Demand Response (DR)	500									
4	NQC of Interruptible/Curtailable DR	400									
5	**Residual Service Area Peak Demand (Line 1 - Sum (Lines 2 thru Line 4)**	**23,800**									
	LOCAL RELIABILITY AREA RESOURCES:										
6	Existing Generation NQC	25,000									
7	Retirements (Announced)	(100)									
8	Retirements (Assumed for this scenario)	(200)									
9	Known/High Probability Additions	100									
10	RPS Additions NQC (Including Imports)	100									
11	Other Utility Planned Additions NQC	300									
12	Other non-Utility Planned Additions NQC	100									
13	Net Interchange (Sum Lines 14 thru 16)	200									
14	*Non-Firm Imports (Require Reserves)*	*2,300*									
15	*Firm Imports (Do Not Require Reserves)*	*700*									
16	*Exports*	*(2,800)*									
17	**Total Service Area Resources (Sum Lines 6 thru Line 13)**	**25,500**									
	SERVICE AREA PLANNING RESERVES:										
18	Available Planning Reserve - not adjusted for firm imports (Line 17 - Line 5)	1,700									
19	Available Planning Reserve (Percentage) (Line 18/Line 5)	7.1%									
20	Lower Bound of Planning Reserve Requirement (Line 5 * 15%)	3,570									
21	Upper Bound of Planning Reserve Requirement (Line 5 * 17%)	4,046									
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
22	Lower Bound 1-in-2 Service Area Surplus (Deficit), Adjusted for Firm Imports	(1,765)									
23	Upper Bound 1-in-2 Service Area Surplus (Deficit), Adjusted for Firm Imports	(2,227)									

*** See notes by line number on following page.**

NOTES (by Line number):

1 Based on CEC's 2009 IEPR 1-in-2 peak demand, which embeds self-served load and committed EE.

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

9 System Resource additions that meet predetermined criteria.

13 Sum of all imports and exports into service area.

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

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

20 Service Area Demand * 15%

21 Service Area Demand * 17%

22 Line 19 + (adjusted for firm imports by adding 15% of Line 15) - Line 21

23 Line 19 + (adjusted for firm imports by adding 17% of Line 15) - Line 22

(End of Attachment 1)

Attachment 2

Energy Division Proposal:
Planning Standards for System Resource Plans

Planning Standards for System Resource Plans

The r resource plans filed by the IOUs, or any other respondent shall conform with the planning standards in this document. In general, standardization addresses (I) definitions, (II) guiding principles, (III) portfolio evaluation criteria; (IV) base case assumptions, and (V) sensitivity analysis, as specified below.

I. Definitions

Scenario - A possible future state of the world encompassing assumptions about policy requirements, market realities and resource development choices. Required scenarios are those specified in the Scoping Memo. Supplemental scenarios are any additional scenarios evaluated in addition to those required in the Scoping Memo.

Portfolio - A set of electric resources, both supply-side and demand-side, that provides electric service to all system ratepayers, under a given scenario.

Utility-Preferred Portfolio **–** A resource portfolio identified by the IOU as a preferred resource portfolio and submitted to the Commission for consideration and possible adoption.

Resource Plan – A filing before the Commission containing information and analysis on all portfolios developed and evaluated, including complete documentation of each portfolio's performance under required evaluation criteria. The filing also submits a utility-preferred portfolio to the Commission for consideration and possible adoption and the rationale for its selection over other portfolios evaluated.

Case – A set of input assumptions and parameters (e.g., gas price, or electricity demand) under a given scenario that drives the selection of a given portfolio of resources.

Base Case – A set of input assumptions and parameters that represent the expected or most likely values for each scenario. All required scenarios shall have the same Base Case assumptions, whereas supplemental scenarios may consider alternative Base Case assumptions.

Sensitivity Analysis - A test to measure the change in output variable (e.g., cost, resource need) due to a change in input assumptions and parameters. Sensitivity analysis is conducted by changing one or more input assumptions from the Base Case to an alternative value.

II. Guiding Principles for Resource Plans

Resource plans filed in this proceeding shall follow these guiding principles:

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

B. Assumptions should reflect the behavior of market participants, to the extent possible.[1]

C. Resource plans should be informed by an open and transparent process.[2]

D. Resource plans should consider whether substantial new investment in transmission and flexible resources such as dispatchable generation or energy storage would be needed to reliably integrate and deliver new resources to loads.

E. Resource scenarios should provide useful information and resource portfolios should be substantially unique from each other.

II. Portfolio Evaluation Criteria

Reliability should be treated as a modeling input constraint, rather than as a separate evaluation metric. The Planning Reserve Margin (PRM), in conjunction with the resource adequacy (RA) program, is the mechanism by which the Commission ensures system reliability levels are maintained. In the system analysis, each resource portfolio should include sufficient levels of resources in order to meet the PRM requirement, currently 15-17% of peak demand.[3] While the IOUs 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, the Commission discourages assessments of reliability benefits outside the PRM proceeding (R.08-04-012 or its successor).

The resource plans filed by the IOUs, or any other respondent shall evaluate and document the performance of each portfolio filed in terms of cost, risk, and GHG emissions metrics. These three categories of evaluation criteria are summarized in Table 1 and described in more detail below.

Table 1: Required Evaluation Criteria for Resource Plans

Criteria	Description
1. Cost	(a) Net Present Value Revenue Requirement (utility cost) (b) Utility average rate (c) Total Resource Cost (customer and utility cost)
2. Risk	Robust scenario and sensitivity analysis

[1] A possible exception is confidential market price data, which may be reasonably substituted with public engineering- or market-based price data.

[2] It is anticipated that the renewable generation portfolios developed by Energy Division staff will be developed according to a transparent and vetted methodology. However, as stated in Guiding Principle B, there are benefits to having commercial activity reflected in renewable generation portfolios. These portfolios may thus reflect some confidential information from the IOUs' RPS solicitations. Access to disaggregated market data may be restricted to non-market participants who sign a non-disclosure agreement, pursuant to D.06-06-066 and its successors.

[3] See D.04-01-050.

3. GHG Emissions	(a) Total GHG emissions during each year of the planning horizon (b) Average, per ton cost of GHG emissions abatement (c) Qualitative assessment of long-term GHG implications

1. Cost

Portfolios shall be evaluated on the basis of at least the following cost metrics: the net present value revenue requirement (PVRR), utility average rate, and PVRR plus customer cost.

(a) Net Present Value Revenue Requirement: The PVRR includes all costs required to meet service area demand that are expected to enter into utility rates. The PVRR includes generation costs as well as transmission, distribution, and all other utility costs. To calculate PVRR, the total, utility 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 must be included in the PVRR calculation. (See Table 3 and discussion below for CO_2 price forecast methodology and GHG policy assumptions used to calculate the effect of CO_2 prices on generation costs and costs to utilities.)

Because fossil fuel and CO_2 allowance prices may continue to rise after the end of the normal 10-year planning period, cost metrics shall be calculated over 20 years, at a minimum. If a 20-year time period is selected, additional analysis to capture "end effects" after the end of the 20-year period should be done. A "salvage value" approach that credits ratepayers with the remaining market value of the resource, given appropriate assumptions for CO_2 price and natural gas price forecasts, is acceptable. We encourage the IOUs to work together to develop a common methodology; however, that methodology should incorporate the market value of the plant and not just the remaining book value.

The utility average rate shall be calculated for each year of the model period as the revenue requirement of each portfolio divided by total sales in that year. A present value of the average rate shall also be calculated (present value of the revenue requirement divided by the present value of the total sales).

PVRR Plus Customer Cost[4]: Many of California's policy goals are aimed at increasing the deployment of distributed energy resources such as EE, DR and renewable DG. Development of these resources often requires substantial customer contributions in

[4] In this proceeding, this criteria refers to the sum of the utility cost and customer cost of the entire resource portfolio. This criteria is closely related to, but not precisely the same as, the Total Resource Cost criteria used in the context of cost-effectiveness determinations of individual EE and other demand-side resource programs.

addition to utility support. The PVRR Plus Customer Cost criteria includes both utility and net 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, including EE, DR, CSI, CHP, and others.

2. Risk

Robust scenario and sensitivity analyses should be conducted to assess a variety of risks associated with a given set of resource portfolios. More detailed guidance on scenarios and sensitivities is provided below in Sections III and V, respectively.

3. Greenhouse Gas Emissions

(a) Total GHG Emissions: Resource plans shall report the total GHG emissions associated with each portfolio during each year of the planning horizon.

(b) Average, Per-ton Cost of GHG Emissions Abatement: Resource plans shall calculate the average, per ton cost of CO_2 emissions reductions for each portfolio, relative to a benchmark portfolio constructed by meeting all resource needs with new natural gas fired resources. The "All-Gas" portfolio is similar to other portfolios submitted for the Commission's review, but is developed for benchmarking purposes only. To calculate the average cost of CO_2 emissions reduction, the change in PVRR relative to the All-Gas portfolio cost is divided by the change in total GHG emissions relative to the All-Gas 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 evaluation criterion because it provides an indication of a portfolio's cost-effectiveness in reducing GHG emissions.

(c) Qualitative Assessment of Long-Term GHG Implications: Resource plans shall 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. 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 GHG benefits and substantial cost reductions and would score highly. We do not intend this assessment to be highly specific and quantitative in nature; rather, we are interested in the perspective of the IOUs' and parties as to which technologies hold the most promise for cost-effective, long-term, electric sector GHG reductions and whether increased investment in those technologies now would have long-term benefits for electric ratepayers in California.

III. Required Scenarios

The Energy Division shall propose a minimum set of renewable generation scenarios in its draft report due in June 2010. In addition to comments on staff's proposed renewable scenarios, the IOUs or any other party may propose other scenarios the Commission should consider to achieve the goals of this proceeding. The Assigned Commissioner will determine a reasonable minimum set of resource planning scenarios in the Scoping Memo, based on initial proposals and parties' comments. The required scenarios shall be consistent with the guiding principles set forth in Section II.

IV. Required Base Case Assumptions for Each Required Scenario

Tables 2 and 3 below summarizes our requirements for base case assumptions in required scenarios evaluated in the IOUs' resource plans. In general, these requirements apply to two categories of assumptions: (1) **load and resource variables** underlying assessments of need for new resources; and (2) **cost variables** underlying computations of total portfolio cost. See discussion below for more detailed descriptions of these requirements.

1. Load and Resource Variables

Table 2 below summarizes our requirements for base case load and resource assumptions in the minimum set of scenarios evaluated in the IOUs' resource plans. We note that preferred resources (e.g., CHP) not already identified in Table 2 shall be reflected in the IOUs' resource plans, with guidance as specified in the Scoping Memo.

Table 2: Requirements for base case assumptions: load and resource assumptions

Variable	Source for Base Case Assumptions
Load and Resource Assumptions	
Load forecast (energy and capacity)	For system RA need assessments, use the most recent IEPR base case 1-in-2 load forecast. For local RA need assessments, use local area forecasts that are consistent with the most recent IEPR base case 1-in-10 load forecast.
Energy efficiency (EE)*	**Committed EE**[5] - Embedded utility EE program savings in the most recent IEPR base case load forecast.

[5] In this OIR, we define *committed EE* as savings from IOU programs implemented in the 2006-2012 period. These are considered committed savings and are embedded in the CEC's 2009 IEPR demand forecast.

Variable	Source for Base Case Assumptions
	Uncommitted EE[6] – Assumed levels of EE savings that are incremental to the most recent IEPR base case load forecast, as specified below.
Demand response (DR)*	IOUs propose forecasted DR load impacts based on April 1st Load Impact Report Compliance Filing pursuant to D.08-04-050 Ordering Paragraph 4, and as specified below.
Customer-side DG, including California Solar Initiative (CSI)	Embedded levels of self-generation in the most recent IEPR base case load forecast.
Peak capacity value	Net Qualifying Capacity (NQC) values per the RA proceeding.[7]
Resource Additions and Retirements *	IOUs propose assumptions on resource additions. The Scoping Memo specifies an approach for plant retirements.
Planning Reserve Margin	15%-17% of peak demand, or as modified in R.08-04-012.
* Includes inputs or assumptions for which the IOUs shall file initial proposals in Q2 2010, pursuant to the Preliminary Schedule in the OIR, or as modified by subsequent ruling.	

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. As part of the IEPR, the CEC documents the amount of EE and other behind-the-meter resources such as solar PV, CHP and other DG that are assumed to be embedded in the forecast.

Energy Efficiency

Decision 08-07-047 states 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."[8] However, the Commission has deferred to the CEC's IEPR process to generate load forecasting information necessary to interpret the

[6] In this OIR, we define *uncommitted EE* as savings from IOU and non-utility programs implemented in the 2013-2020 period to achieve the Commission's EE savings goals adopted in D.08-07-047, as modified by D.09-09-047 and subsequent decisions.
[7] The updated NQC list is publish at www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_guides_2008-09.htm.
[8] D.08-07-047, OP 3, at p. 39.

impacts of TMG energy savings goals on procurement. Specifically, CEC and Commission staffs collaborated in the 2009 IEPR proceeding to develop forecasts of uncommitted EE (i.e., TMG energy savings not embedded in the forecast.)[9]

In this proceeding, Base Case assumptions for EE shall reflect the sum of (1) utility EE program savings embedded in the most recent IEPR demand forecast , and (2) incremental EE savings reasonably expected to occur from implementing the IOUs' EE goals, relative to the most recent IEPR load forecast. Base Case assumptions shall represent 100% of the current EE goals or alternative assumptions, as specified in the Scoping Memo with input from parties. The Assigned Commissioner shall consider the most recent CEC forecasts of incremental EE relative to the IEPR demand forecast, as well as other relevant information in establishing a reasonable Base Case assumption for each IOU. The Scoping Memo shall require sensitivity analysis based on different expectations of EE policy achievements, including 100% of the current numerical EE goal for each IOU (if not already required as a Base Case assumption).

Demand Response

Base Case levels of demand response (DR) assumed in required scenarios shall 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 IOUs' Automated Metering Infrastructure (AMI) systems.

The utilities shall estimate the ex-ante annual load impact forecast (2011-2020) based on approved DR programs. Forecasts shall also include AMI-enabled DR, such as price-responsive programs adopted or directed by the Commission, but yet to be implemented,[10] and any default and optional dynamic rates expected in the forecast period.

The estimated ex-ante load impact forecast filed in this proceeding shall be based on the April 1, 2010 Load Impact Report Compliance Filing pursuant to Ordering Paragraph 4, D.08-04-050. The utilities should report DR load impact forecast for LTPP using the August Monthly System Peak Load Day under a 1-in-2 Weather Condition. If utilities are unable to provide estimated ex-ante load impact forecast for DR programs that have yet to be implemented[11] by June 2010 along with other non-RPS planning assumptions, then the utilities can include them in resource plans filed in (est.) Q1 2011. By Q1 2011 when resource plans are expected to be filed, if there are substantial changes in the load impact forecast for certain individual DR programs[12] originally estimated in June 2010, parties will be provided opportunity comment on revised estimates in filed testimony.[13]

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[9] See CEC Committee Report, *Incremental Impact of Energy Efficiency Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast.* http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html.

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

[11] For example, PTR and Default CPP.

[12] New programs that may not have enough data such as Peak Choice.

[13] Q2 2011

Resource Additions and Retirements

IOUs shall specify resource additions and retirements, as listed in the standardized physical system capacity need tables (Attachment 1). IOUs shall specify which resource additions and plant retirements are assumed. "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.

The Scoping Memo shall specify an approach to plant retirement assumptions for required scenarios in the IOUs' resource plans, consistent with implementation of the state's OTC policy.

1. Cost Variables

Table 3 below summarizes our requirements for Base Case cost assumptions in the minimum set of scenarios evaluated in the IOUs' resource plans. See discussion below for more detailed descriptions of these requirements.

Table 3: Requirements for base case assumptions: cost assumptions

Variable	Source for Base Case Assumptions
Cost Assumptions	
Renewable resource availability	Final Staff Renewables and Transmission Study, as derived from RETI and other sources.
Renewable resource cost	Final Staff Renewables and Transmission Study, as derived from RETI and other sources.
Conventional and other resource cost and performance *	MPR values for CCGT. IOUs propose for others
New generation tax and financing assumptions *	For new renewables, use assumptions in the Final Staff Renewables and Transmission Study. For other technologies, IOUs propose.
Transmission cost assumptions *	For transmission to access new renewables, use assumptions in the Final Staff Renewables and Transmission Study. For other transmission, IOUs propose.
Distribution cost	EE Avoided Cost methodology

Variable	Source for Base Case Assumptions
assumptions	
Natural Gas Price	Most recent MPR methodology
CO_2 Price	Most recent MPR methodology
GHG Policy Assumptions	Prior to evaluating the base case portfolio, the IOUs will develop a common set of GHG allowance (and/or allowance revenue) allocation scenarios based on the latest guidance from the ARB Cap and Trade policy development process (and any meaningful Federal policy developments), based on staff and parties' input.
* Includes inputs or assumptions for which the IOUs shall file initial proposals in Q1 2011, pursuant to the Preliminary Schedule in the OIR, or as modified by subsequent ruling.	

Natural Gas Fuel Price Forecast

Subject to change by the Commission in subsequent MPR decisions, the IOUs shall use the MPR gas price forecasting methodology (not actual values) for the Base Case gas price forecast in the LTPP. We direct this in order to avoid re-litigating an issue that the Commission has already decided in another procurement-related proceeding.

The IOUs shall use the same quote date, as specified in the Scoping Memo. It is expected that each IOU will have different gas forecast values due to each utility's unique basis differentials and gas delivery costs.

CO_2 Price Forecast

When the IOUs file their 2010 resource 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 this time. Therefore, the Commission does not expect that relevant, real price data will be available when the IOUs file their 2010 resource plans. With this in mind, the IOUs' base case analysis shall use the CO_2 price forecast methodology applied in the most recent MPR decision.

V. Required Sensitivity Analysis

The IOUs shall test the robustness of the base case portfolio against changes in a limited and influential set of variables. IOUs may assume that the resource portfolio and dispatch would not change under the sensitivity analysis. For example, sensitivity analysis of total portfolio cost would simply apply different gas, CO2 and/or technology cost assumptions to a fixed resource portfolio. The IOUs shall run eight sets of sensitivities: two sets for each of the four variables. During the course of the proceeding, the IOUs may be directed to run additional combinations of sensitivities. Table 4 below specifies the required sensitivity analyses.

Table 4: Requirements for required sensitivity analysis

Variable	Requirement
1. Natural Gas Prices *	Each portfolio shall be evaluated using a "High Gas Price" and "Low Gas Price" sensitivity analysis, corresponding to feasible extremes of natural gas prices. The Scoping Memo shall establish values to be used for sensitivity analysis, based on initial IOU proposals for High- and Low-Gas Price assumptions and parties' comments and/or alternative proposals.
2. CO_2 Prices *	Each portfolio shall be evaluated using a "High CO_2 Price" and "Low CO_2 Price" sensitivity analysis, corresponding to feasible extremes of CO_2 price. The Scoping Memo shall establish values to be used for sensitivity analysis, based on initial IOU proposals for High- and Low-CO_2 Price assumptions and parties' comments and/or alternative proposals.
3. Need Level *	The utility-preferred portfolio shall be evaluated using a "High-Need" and "Low-Need" sensitivity analysis, corresponding to levels of uncertainty in the achievements of policy-driven demand-side programs. The "Low-Need" sensitivity should reflect more optimistic assumptions about policy-driven resource achievements (e.g., EE, DR, customer-side DG, and CHP). These sensitivities are designed to reflect total need adjustments, not as permutations of a single policy-driven resource assumption (with the exception of EE as noted below.) The "High-Need" sensitivity should reflect more conservative assumptions about policy-driven resource achievements. The Scoping Memo shall establish numerical values to be used for sensitivity analysis, based on initial IOU proposals as well as parties' comments and/or alternative proposals. For EE resources, the TMG numerical value adopted in D.08-07-047, as modified in subsequent decisions, must be one component of the High-, Low-, or Base-Need levels required by the Scoping Memo.

Variable	Requirement
4. Technology Cost *	Sensitivity analysis should test the effect on a portfolio's cost if the cost of a selective set of resources drops substantially over time. The base case portfolio should be evaluated using a "High Cost" and "Low Cost" sensitivity analysis for selected technologies (e.g. photovoltaics), corresponding to feasible extremes of technology cost. The Scoping Memo shall establish numerical values to be used for sensitivity analysis, based on initial IOU proposals, as well as parties' comments and/or alternative proposals.
* Includes inputs or assumptions for which the IOUs shall file initial proposals in May 2010, pursuant to the Preliminary Schedule in the OIR, or as modified by subsequent ruling.	

(End of Attachment 2)