R.12-03-012: Energy Division Straw Proposal – Planning Standards

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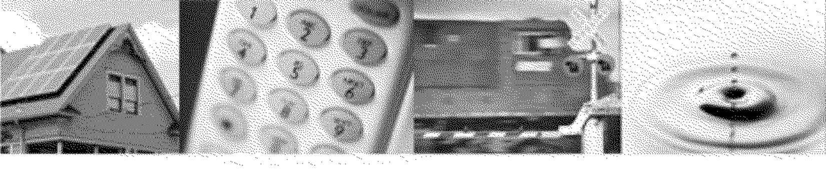
California Public Utilities Commission

May 17, 2012



Agenda

Time	Item
10:00 - 10:10	Introduction, Schedule
10:10 – 10:25	Background, Roadmap
10:25 - 12:00	Demand-side Assumptions
12:00 – 1:00	Lunch
1:00 – 2:00	Supply-side (Non-RPS) Assumptions
2:00 – 2:45	Supply-side (RPS) Assumptions
2:45 – 3:00	Break
3:00 – 3:30	Allocation methodologies for Energy Efficiency (Mike Jaske, CEC)
3:30 – 3:45	Allocation methodology for Demand Response (Donald Brooks)
3:45 – 4:00	Wrap-up/Next steps

Call in #:
866-687-1443
*Note: *6 to mute/unmute*

Passcode:
737358

Workshop Purpose

- Familiarize parties with straw proposal assumptions in order to assist with comments and reply comments

Standards Schedule

- 5/31 – Comments
- 6/11 – Reply Comments

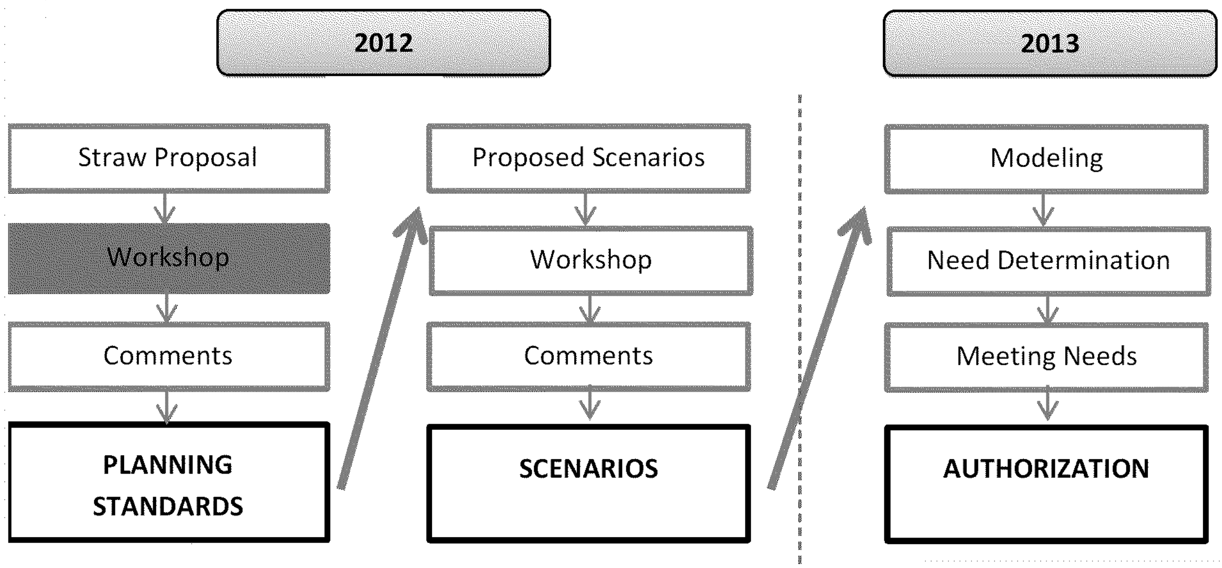
Anticipated:

- 8/1 – Draft Scenarios Straw Proposal
- 12/31 – Decision on Standards & Scenarios

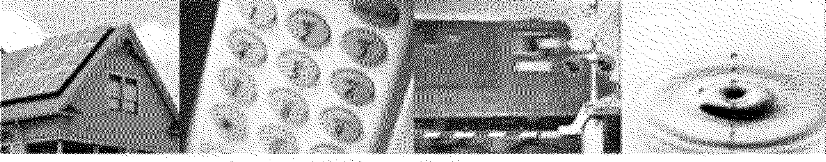
Other Anticipated Schedule

- Track I (Local Area Reliability)
  - 5/23 – CAISO testimony on LCR
  - Late June – Other parties' testimony on LCR
  - Hearings – 8/7-10 & 8/13-17
    - If needed
    - Some subset of days may be selected
- Track III (Bundled Procurement / Rules)
  - Q3 2012 start expected

Roadmap



= **Commission / ALJ / Assigned Commissioner action point**



Problem Statement

Scenarios should be developed to answer the following primary questions:

- What new infrastructure needs to be constructed to ensure adequate reliability?
- What mix of infrastructure minimizes cost to customers over the planning horizon?

Guiding Principles

Assumptions

- Realistic view of expected policy-driven resource achievement
- Reflect real-world possibilities

Scenarios

- Informed by transparent and open process
- Inform new resource investments
- Provide policy information
- Inform bundled procurement plans
- Limited in number based on current LTPP policy objectives

Spreadsheets, not snapshots

Assumptions Overview

Demand

Peak Weather Impacts
Economic and Demographic Drivers
Load Forecast
Incremental Uncommitted Energy Efficiency
Non-Event Based Demand Response
Incremental Small Photovoltaic (behind the meter)
Incremental CHP (behind the meter)

Supply

All Resources
Existing Resources
Imports
Resource Additions
Event-Based Demand Response
Incremental CHP (supply-side)
Resource Retirements

Allocation Methodologies

Planning Area

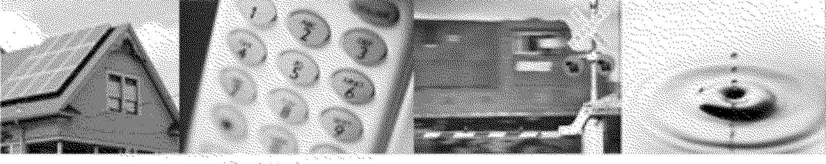
CAISO controlled transmission grid & distribution systems

- Resources in CAISO footprint
- Resources outside footprint
  - Directly connected
  - Dynamically transferred
- Includes:
  - Existing Transmission
  - New transmission approved by CAISO and CPUC expected online in the planning period
  - Minor Upgrades (does not require a new right of way)

Planning Period

- Period 1
  - 1 to 10 year detailed look
  - Similar to that traditionally done in LTPP
  - 2013-2022
- Period 2
  - 11 to 20+ year simplified look
  - Simplified demand assumptions to extend understanding of future planning horizon
  - 2023-2034

Demand-side Assumptions



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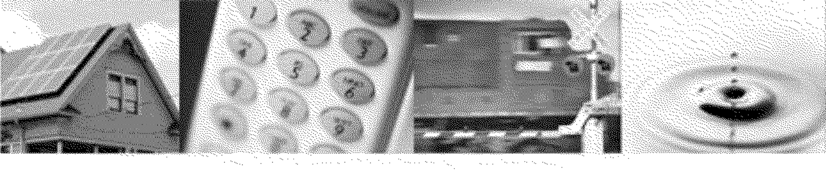
Allocation Methodologies



Background

- Demand side assumptions are one of two types
  - Base values
  - Incremental values

Base values may be largely considered independent, while incremental values are modifications to a base value.

Example – EE beyond that committed in the CEC's Demand Forecast (Base), is an Incremental value.

Background (cont)

- The LTPP combines Base and Incremental values to create a "managed" forecast

- Staff proposes a total of three demand-side scenarios:
  - Low, Middle, and High

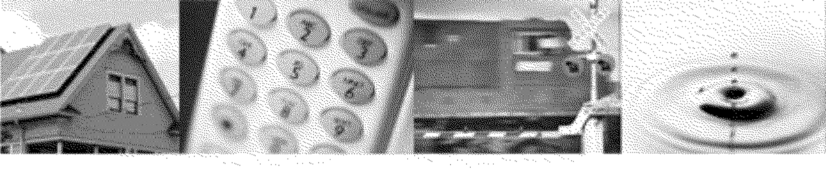
- Peak weather adjustments should be conducted on the Middle scenario

Economic / Demographic Drivers

Economic Growth		
Low	**Mid**	**High**
Moody's protracted slump	Moody's base case	Global Insight optimistic
Vintage:	October 2011	
Population Growth		
Typical	CA Department of Finance, Long Term Forecast	
Alternative	Moody's Analytics	
Vintage:	October 2011	

Economic and demographic drivers should be taken from the most recent California Energy Demand forecast.

See the CEC's 2011 Integrated Energy Policy Report for more information.



Load Forecast

Forecast Snapshot *				
	2010	2022		
	Recorded	Low	Mid	High
MW	48,564	53,378	55,951	58,412
GWh	212,214	235,203	243,362	258,229
Vintage:		Revised CED (Feb '12)		
* Values taken from Forms 1.1b & 1.3 (each IOU)				

Average Load Growth				
	2000-2010 *	2011-2022 **		
	Recorded	Low	Mid	High
MW ***	1.21%	1.13%	1.57%	1.95%
GWh	0.25%	0.87%	1.14%	1.60%
Vintage:		Revised CED (Feb '12)		
* Values taken from Forms 1.1b & 1.3 (Statewide)				
** Values taken from Forms 1.1b & 1.3 (each IOU)				
*** Statewide coincident peak				

The most recent adopted CEC California Energy Demand forecast should be used as the base forecast. In the advent of an older adopted forecast, the revised forecast may be utilized.

The current adopted California Energy Demand forecast is from the 2009 IEPR, and the most recent revised forecast is from February 2012.

Incremental EE

Some level of incremental energy efficiency should be included for long-term planning. The 2011 Potential study, as the most current information should inform the CEC's analysis regarding incremental EE impacts relative to the California Energy Demand forecast.

Incremental Energy Efficiency		
Low	**Mid**	**High**
5% lower than Mid	CEC Mid Inc-EE	15% higher than Mid

Precise values for these levels of incremental EE are expected in May or June from the CEC.

Non Event-Based DR

Incremental Non-Event Based Demand Response		
Low	**Mid**	**High**
Same as CED	Same as CED	Same as CED

Non Event-Based DR values should be the same as embedded into each scenario from the most recent California Energy Demand forecast. Event-Based DR is treated as a supply-side resource.

Incremental Small PV

Incremental Small PV		
Low	**Mid**	**High**
2,200 MW *	2,500 MW total	3,000 MW total
* Reflective of no net change from amount embedded in CED		

The impacts of some programs, such as the California Solar Initiative are embedded in the California Energy Demand forecast. Amounts of small photovolatics proposed here are incremental to those values. These programs are solely behind the meter.

Incremental CHP - Demand

- The impacts of some CHP programs are embedded in the California Energy Demand forecast
- Amounts of CHP proposed here are incremental to those values
- Programs accounted for here are reductions in load
- Programs exporting energy are accounted for on the supply-side
- MW values are attained by 2030 with linear growth

Incremental CHP (cont)

Incremental Demand-Side CHP			
	Low	**Mid**	**High**
Assumptions	No change in net CHP capacity.	ICF Base Case	ICF Mid Case
Assumption Details	33% RPS; Retirements are replaced with new CHP, keeping the current CHP capacity unchanged	Cap and trade, SGIP with program expiration in January 2016, 33% RPS, AB 1613 CHP Pricing for CHP under 20 MW, SRAC export pricing for CHP over 20 MWs	SGIP is extended beyond 2016, 33% RPS, Stimulus for export projects larger than 20 MWs, Increased market participation due to removal of barriers and risk by 5-20%
Nameplate MW	0	1,672	1,968
Capacity Factor	75%		
Vintage:		Revised February 2012 ICF CHP Policy Analysis and 2011-2030 Market Assessment Consultant Report, expected Summer 2012	

Supply-side Assumptions

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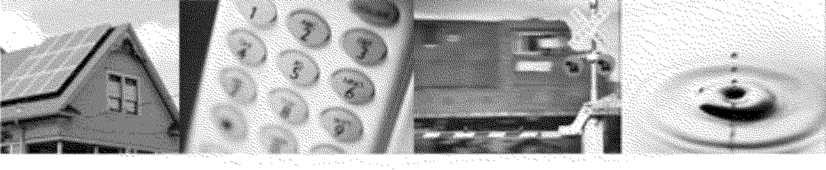
Allocation Methodologies

Background

- Supply-side assumptions are for planning purposes and not indicative
  - Inclusion or exclusion of specific projects or resources has no implications for existing or future contracts
  - Assumes an electrically equivalent resource would be selected if a forecast resource were to become unavailable



Accounting

- All resources should be
  - Identified as system or by local area / subarea
  - Accounted for via
    - Most recent NQC
    - Absent an NQC, a forecast should be made in light of actual or expected installed capacity
  - Existing resources NQC will be posted on the CPUC website
  - Variable resources should include a production profile

Imports

- Based on Maximum Import Capability into CAISO
  - As used in RA program
  - Including expansions identified in CAISO TPP
- Resources outside of the CAISO should be taken from the publically available TEPPC data
  - Currently the 2022 Common Case generation table

Resource Additions

Non-RPS resources should be included if they meet either Known or Planned definitions

- Known Additions
  - Contract in place
  - Permitted
  - Under construction
- Planned Additions
  - Contract in place

Deliverability

Resources should be assumed deliverable if they meet one of two criteria:

- Fits on existing or approved transmission
- Baseload or flexible resources

Resources not meeting these criteria would be considered energy only.

Resource Additions Summary

Resource Additions				
	Known	**Planned**	**Location**	**Deliverable**
Non-RPS	Contracted resource NQC, permitted, and under construction	Contracted resource NQC, plus Known resources	Specific Local Area or System	Only if baseload or flexible, or fits on existing or approved Transmission
RPS	Scenario based, see RPS specific scenarios		Specific Local Area or System	Only if baseload or flexible, or fits on existing or approved Transmission

Event-Based DR

Event-Based Demand Response			
Low	**Mid**	**High**	**Location**
10% lower than Mid	Most recent Load Impact Reports filed	10% higher than Mid	Per DR methodology, Appendix A

Event-based DR should be accounted for as a supply-side resource. The most recently filed Load Impact reports filed with the CPUC should serve as the Mid value.

For PG&E this should include the pending Peak Time Rebate Program

Incremental CHP - Supply

- Amounts of CHP proposed here are incremental to the California Energy Demand forecast
- Programs accounted for here are exporting electricity to the grid
- Programs serving on-site load are accounted for on the demand-side
- MW values are attained by 2030 with linear growth

Incremental CHP (cont)

Incremental Supply-Side CHP			
	Low	**Mid**	**High**
Assumptions	No change in net CHP capacity.	ICF Base Case	ICF Mid Case
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Nameplate MW	0	213	1,661
Capacity Factor	75%		
Vintage:		Revised February 2012 ICF CHP Policy Analysis and 2011-2030 Market Assessment Consultant Report, expected Summer 2012	

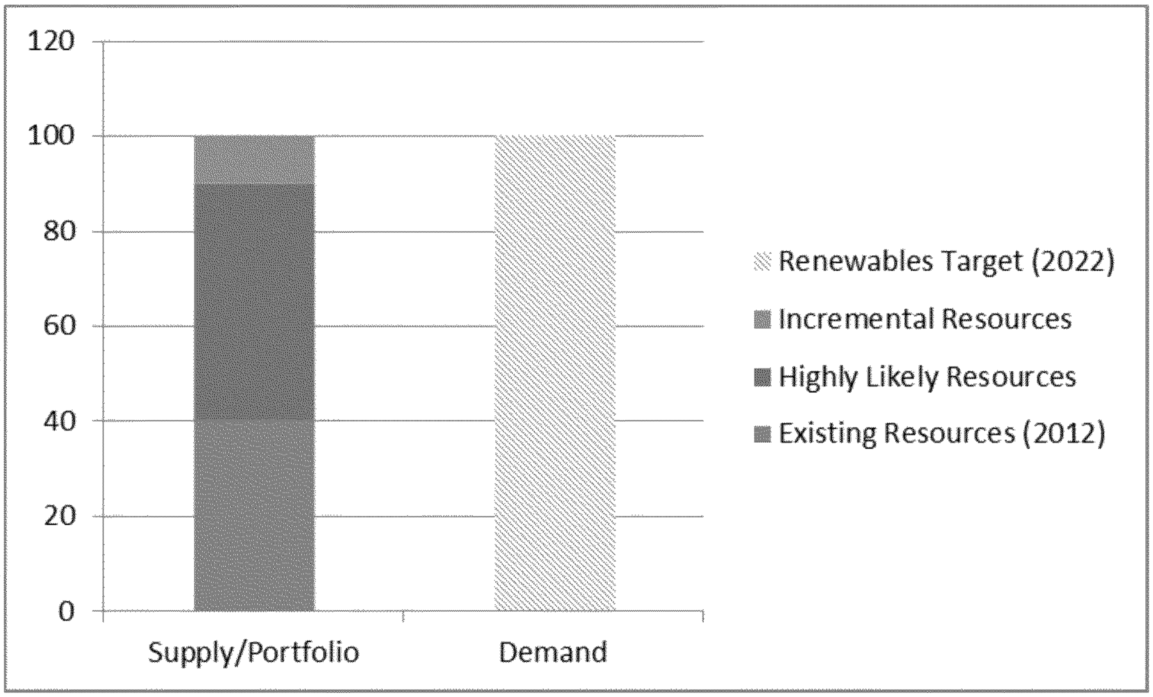
Supply-side Assumptions: RPS

RPS Target & Supply

- RPS Target established in LTPP
  - Currently 33% of retail sales in 2020
  - Other interim targets
- Supply methodology established in RPS proceeding
  - R.11-05-005

What is a RPS Portfolio?

A set of RPS supply resources assumed to be operational in the study year



* Existing resources should be decremented for assumed retirements

What do Portfolios Mean?

- Portfolios will be studied in 2013 for the CAISO’s TPP and in flexibility studies
- Inform investment decisions:
  - Need for other resources to meet needs
  - Transmission
- These investment decisions will constrain other future alternatives

RPS Portfolios

Renewable Portfolio Development				
Portfolio	**Expected**	**Incremental**	**Sensitivity**	**Location**
Base	As established in R.11-05-005	Fill RPS target short by cost	Fill RPS target short by cost in preferred locations	Specific Local Area or System
High DG	As established in R.11-05-005	Fill RPS target short with DG resources by cost	Fill RPS target short by cost in preferred locations	Specific Local Area or System

RPS Portfolio Development

- Base Portfolio
  - RNS filled based on cost
    - Cost is defined of net market value
    - Includes transmission costs
    - Excludes capacity value
    - Calculated from Attachment A to Q4 2011 “Renewables Portfolio Standard Quarterly Report”
- High DG
  - RNS filled based on DG programs based on cost
  - Developed from technical potential study for local PV
    - Recommends using least net cost, no learning, no extended investment tax values

Sensitivity

- Any RNS calculated by selecting projects in preferred locations by cost
- Preferred location defined as:
  - Low environmental score (25 or less) in 33% RPS calculator
  - Site in a region generally near low-scoring sites and not near high scoring sites
  - Site evaluated by CEC staff in this proceeding as having a low environmental score
  - Generation project already possessing an environmental permit

Long-term Target

- Maintain 33% RPS post-2020
- Linear progression to a 40% RPS by 2030
  - Incremental additions selected by low cost

Retirements

- Parties expected to provide current public information
- Due to uncertainties, retirements are based on facility age

Retirements (cont)

Retirement Scenarios			
	Low	**Mid**	**High**
Announced	Retirement date	Retirement date	Retirement date
OTC	Same as Mid	The earlier of SWRCB deadline or announced retirement date;, Track II treated as continued operation of the existing facility	The earlier of SWRCB deadline or announced retirement date; Track II treated as retirement
Nuclear	Relicensed for continuous operation	Retire at end of license	Retire in 2015
Hydro	All units repowered at end of life	Retire at 70 years	Retire at 50 years
Renewables	All units repowered at end of life	Retire at 25 years	Retire at 20 years
Other	All units repowered at end of life	Retire at 40 years	Retire at 25 years

Allocation Methodologies

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Allocation Methodologies

Allocation Methodologies: Incremental Energy Efficiency

Mike Jaske (CEC)

Evaluating Demand-side Policy Initiatives for Impacts on Local Capacity Requirements

Mike Jaske
California Energy Commission
4/10/2012

The Context

- AB 1318 (V. Manuel Perez, 2009) requires ARB, in cooperation with CEC, CPUC, ISO, etc. to determine for South Coast Air Basin:
  - Capacity additions needed for reliability
  - Emission offsets required for capacity additions
  - Recommendations for changes to permitting practices and regulations

The Approach

- California Clean Energy Future process devised a set of scenarios for electricity planning
- Incremental demand-side policy initiatives not included within the CEC's adopted demand forecast are translated into busbar-level load reductions for year 2021 to allow the ISO to conduct transmission studies
- The ISO uses busbar-level load reductions to modify power flow base cases and runs LCR studies

Incremental Energy Efficiency

(beyond that included in CEC demand forecasts)

	2021 Peak Demand Impacts by IOU(MW)		
	PG&E	SCE	SDG&E
Residential	1512	1560	310
Commercial	540	733	168
Industrial	223	168	17
Total	2275	2461	496

Note 1: @ customer meter without T&D losses

Note 2: Source – CPUC 2010 LTPP Scoping Memo (Feb. 2011)

Approach

1. Extract annual peak load results for each customer class from the CEC Incremental Uncommitted Energy Efficiency report for all years 2013 to 2020.
2. Obtain results of CPUC data request to each IOU (circa spring 2011) that identifies summer peak load by busbar and the split to major customer sector.
3. Multiply total busbar peak load by customer sector proportions to get absolute value of load at peak for each customer sector.
4. For each customer class, tabulate results of step 3 to determine the proportion that each busbar is of total IOU service area end-user demand for each customer sector.

Approach, cont'd

5. For each year 2013 to 2020, multiply the IOU service area peak load savings for each customer sector from step 1 by the customer sector proportion of each busbar from step 4.
6. Add up the three customer sector values at each busbar of step 5 to compute the total program impacts at each busbar. Extend the same values from year 2020 to be savings for year 2021.
7. Verify that the sum of impacts across all busbars matches the service area starting peak load impacts of Step 1.
8. Provide bus by bus results to ISO for use in LCR studies for a mid-net load case.

ISO - LCR Requirements for 2021(MW)

Area	High Load Case	Mid-Net Load Case
LA Basin (w/o Mira Loma Load Transfer)	12567	10761
LA Basin (with Mira Loma Load Transfer)	11246	10311
Western LA Sub-area	7408	6458
OTC "Need"	1870 - 2884	802 - 1275

Note 1: Environmental RPS Scenario

Note 2: Source is 2011-12 Transmission Report, Table 3.3-25 and Table 3.4-2

Conclusions

- Incremental energy efficiency policy initiatives can have a large impact on local capacity area requirements
- The 2011-12 Transmission Plan does not rely upon adjustments to CEC demand forecasts, thus there is disagreement among CEC, CPUC and ISO about whether or not to rely upon uncommitted energy efficiency or other demand-side policy initiatives

Allocation Methodologies: Demand Response

Donald Brooks

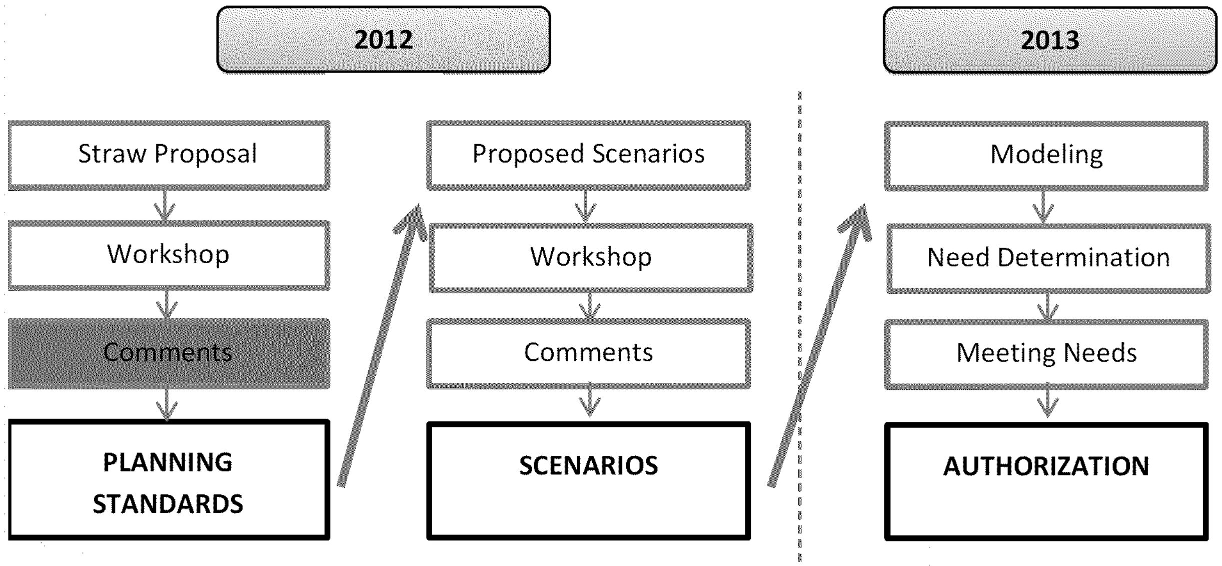
Next Steps

- Scoping Memo expected soon
- Comments due 5/31
- Reply Comments due 6/11
- Adoption of Planning Standards

- Scenario Creation

- May 23 – CAISO LCR needs testimony

Next Steps: Roadmap



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Thank you!
For Additional Information:

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www.GoSolarCalifornia.ca.gov
www.CalPhoneInfo.com