Summary of Preliminary Results of 33% Renewable Integration Study – 2010 CPUC LTPP Docket No. R.10-05-006

May 10, 2011

SECTION 1: INTRODUCTION AND OVERALL STATUS

Contents of Presentation

Introduction and Study Background:

- In a coordinated effort, the IOUs, E3, Plexos Solutions, Nexant, and the ISO conducted Step 1 and Step 2 modeling for the four renewable portfolio scenarios described in 12/3/10 Ruling:
  - Trajectory
  - Time Constrained
  - Cost Constrained
  - Environmentally Constrained
- The study results are dependent upon the scenario modeling assumptions described in the 12/3/10 CPUC scoping memo, with database modifications described in this presentation
- These preliminary results being provided according to schedule established in 3/1/11 Ruling
- ISO will conduct additional sensitivity analysis to validate preliminary results
- Final results will be provided with June 3 testimony

Study Coordination

- April 29 results were produced through a collaborative process between the IOUs and the ISO (and their contractors)
- ISO Activities:
  - Condition Step 1 and Step 2 input data. Contractor: Nexant
    - ISO also requested analytical support from E3, PLEXOS Solutions and IOUs. ISO made final decision on all Step 1 and Step 2 inputs.
  - Calculate Step 1 results. ISO using PNNL software
  - Calculate Step 2 results. Contractor: PLEXOS Solutions
    - ISO directed production of Step 1 and Step 2 results for all scenarios (IOUs did not produce Step 1 or Step 2 results independently of ISO)
- IOU Activities:
  - Calculate Step 3 results. Contractor: E3

Objectives of the 33% Renewable Integration Study and Role of the ISO

1. Identify operational requirements and resource options to reliably operate the ISO controlled grid (with some assumptions about renewable integration by other Balancing Authorities) 33% RPS in 2020
   - Provide estimates of operational requirements for renewable integration (measured in terms of operational ramp, load following and Regulation capacity and ramp rates, as well as additional capacity to meet operational reliability requirements)
   - Analyze sensitivity variables that affect the results
     - Impact of different mixes of renewable technologies and other complementary policies
     - Load growth
     - Impact of forecasting error and variability

Objectives of the 33% Renewable Integration Study and Role of the ISO (cont.)

2. Inform market, planning, and policy/regulatory decisions by the ISO, State agencies, market participants and other stakeholders
   - Support the CPUC to identify long-term procurement planning needs, costs and options
   - Inform other CPUC, and State agency, regulatory decisions (for example, Resource Adequacy, RPS rules, once through cooling [OTC] schedule)
   - In coordination with the CPUC, inform ISO and state-wide transmission planning needs to interconnect renewables up to 33% RPS
   - Inform design of ISO wholesale markets for energy and ancillary services to facilitate provision of integration capabilities

Study approach – overview of modeling tools utilized and proposed for LTPP methodology

- *Step 1* – Statistical Simulation to Assess Intra-Hour Operational Requirements
  - Estimates added intra-hour requirements under each studied renewable portfolio due to variability and forecast error
  - Calculates the following by hour and season: Regulation Up and Regulation Down capacity, load-following up and down capacity requirements, and operational ramp rate requirements
- *Step 2* – Production Simulation
  - Optimizes commitment and dispatch of resources in an hourly time-step to meet load, ancillary services and other requirements at least cost.
  - Uses Step 1 Regulation and load following capacity requirements to reflect intra-hourly operations
  - Calculates production cost-based energy prices, emissions, energy and ancillary services provided by units, violations of system constraints and additional capabilities required to eliminate violations

Status of ISO Methodology and Simulations

- Step 1 methodology under review for assumptions about solar forecast error
- Step 2 methodology reflects modified assumptions discussed in prior workshop (and reviewed in these slides) and additional modifications based on LTPP analysis
- Preliminary Step 2 simulation results now available for review
- Opportunities for further refinement of both Step 1 and Step 2 methodology prior to next batch of CPUC scenario assumptions
- Would like to continue working with the IOUs on an All Gas case, High Load Growth case and a 2011 base case

This presentation builds on prior ISO presentations at CPUC LTPP workshops

- These slides reference:
  - ISO August 24-25, 2010 presentation
  - ISO October 22, 2010 presentation

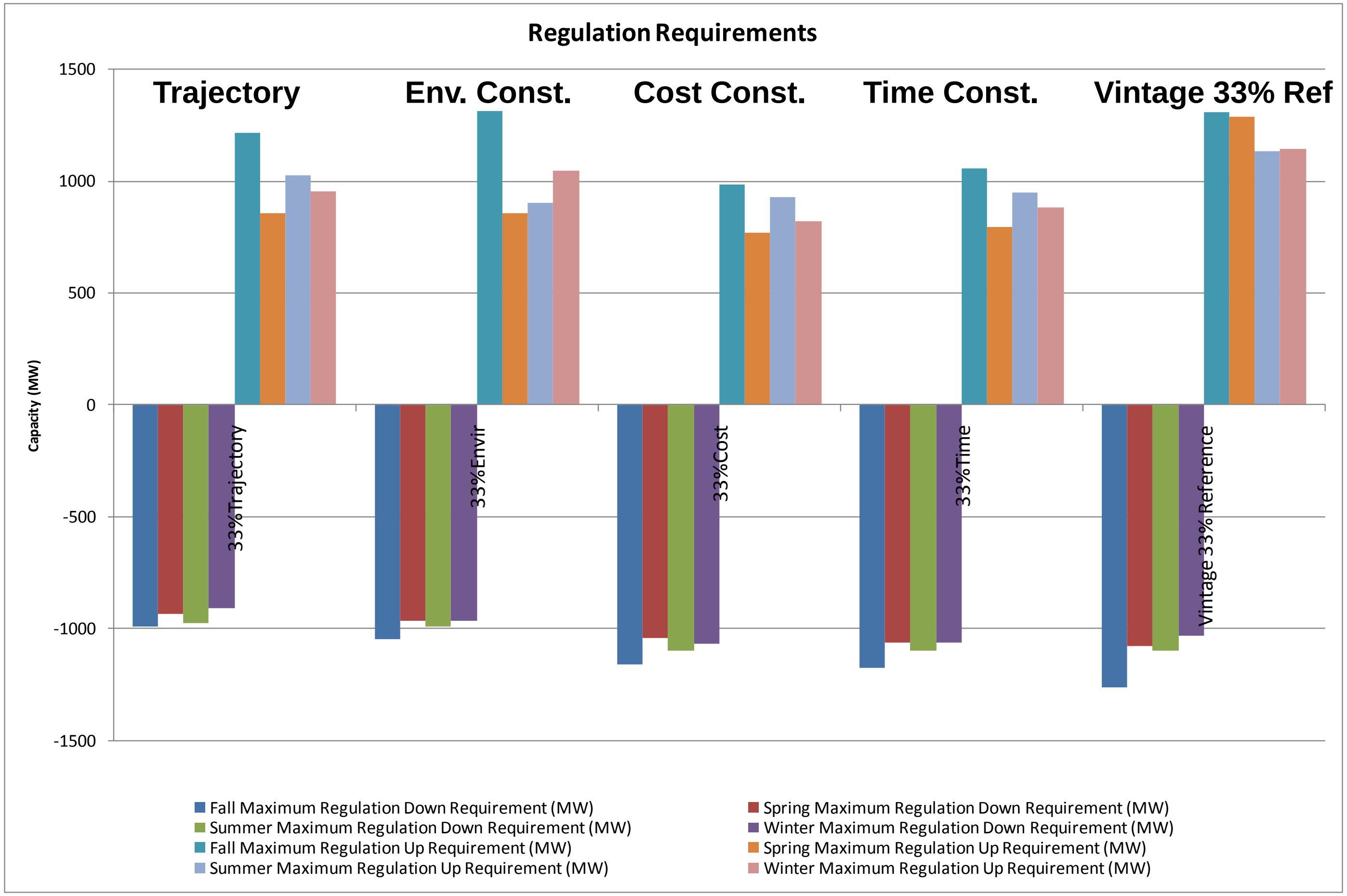
- Prior ISO slides available at
  - http://www.cpuc.ca.gov/PUC/energy/Renewables/100824_workshop.htm

SECTION 2: OPERATIONAL REQUIREMENTS RESULTS (STEP 1)

Step 1 Operational requirement results

- Regulation and load following requirements determined 2010 CPUC-LTPP scenarios
- New load, wind and solar profiles were developed
- Updated load, wind and solar forecast errors were used to calculated requirements
- Refer to appendix for changes to profile and forecast error
- Load following requirement reduced from vintage cases due to reduced forecast errors
- Regulation requirements increased in some hours due to increase in 5 minute load forecast

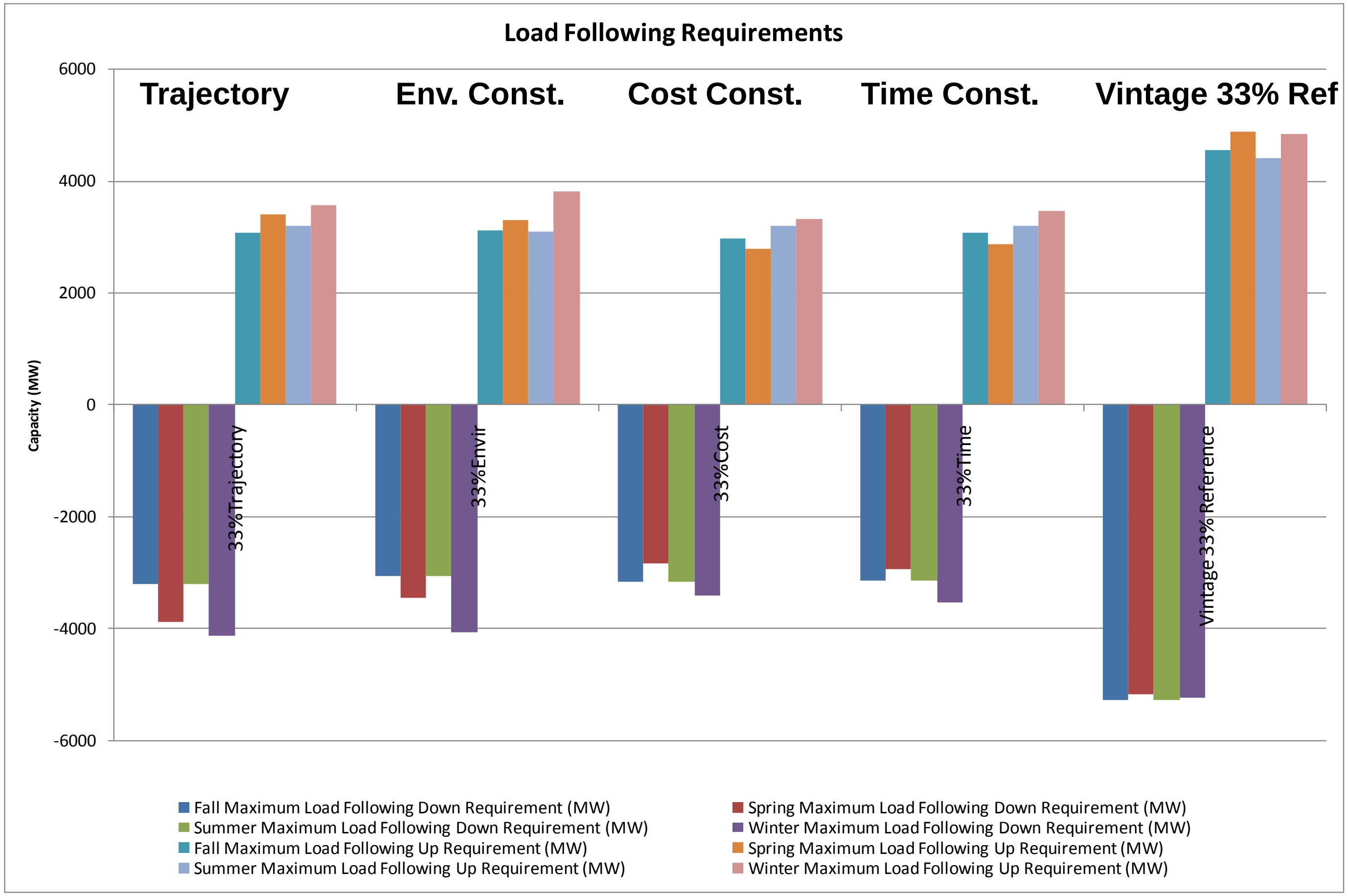
Step 1: Hourly regulation capacity requirements, by scenario



Notes:

- For purposes of comparison, the figures show the single highest hourly seasonal requirement from Step 1 for each season (using the 95th percentile)
- The actual cases use the maximum monthly requirement by hour for need determination and hourly value for production cost and emissions
- Discussion of sensitivity in Section 3

Step 1: Hourly load-following capacity requirements, by scenario



Notes:

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- The actual cases use the maximum monthly requirement by hour for need determination and hourly value for production cost and emissions
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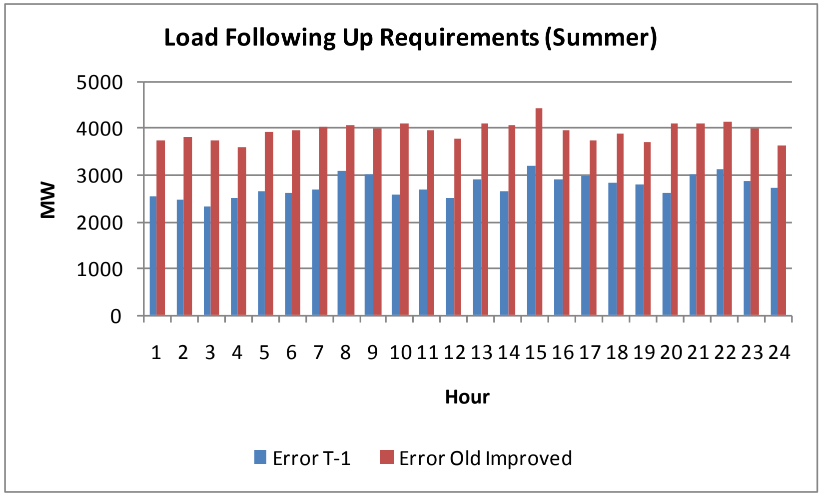
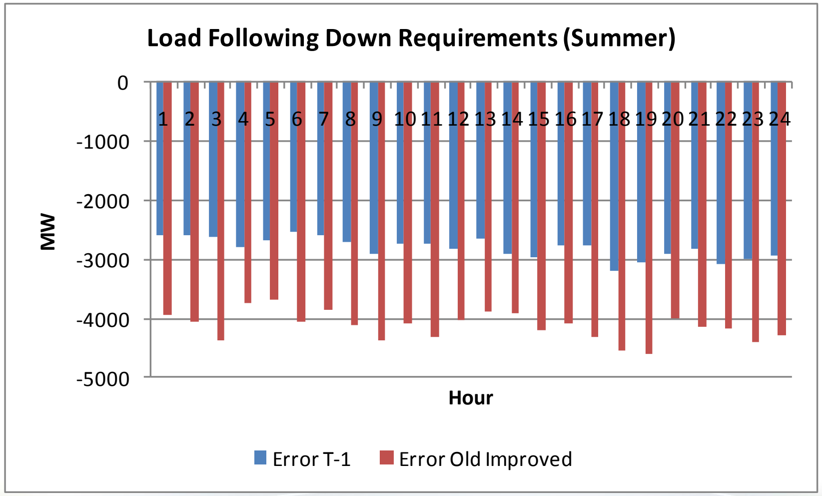
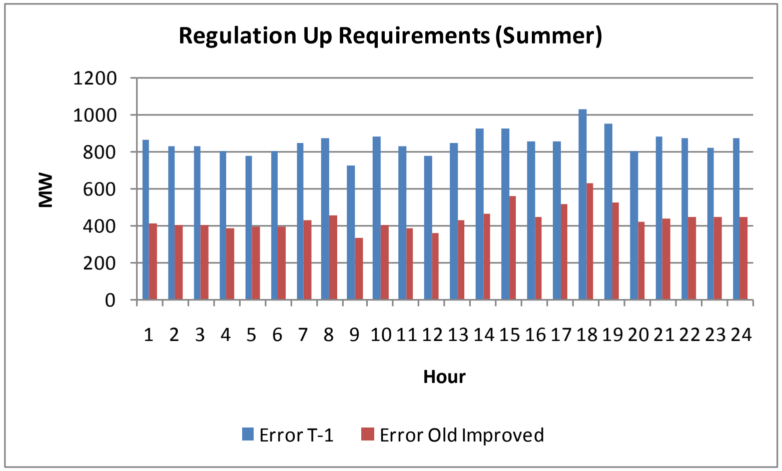
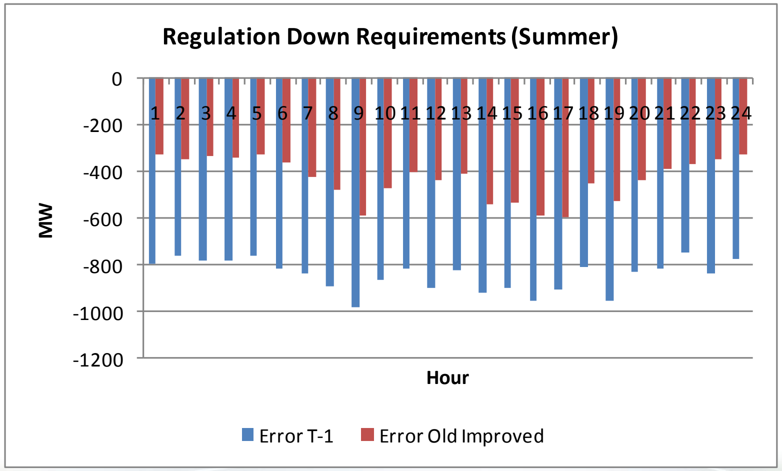
Comparison of load following requirements using refined and previous forecast error. Decrease in load following requirements reflect decrease in T-1 hour forecast errors.



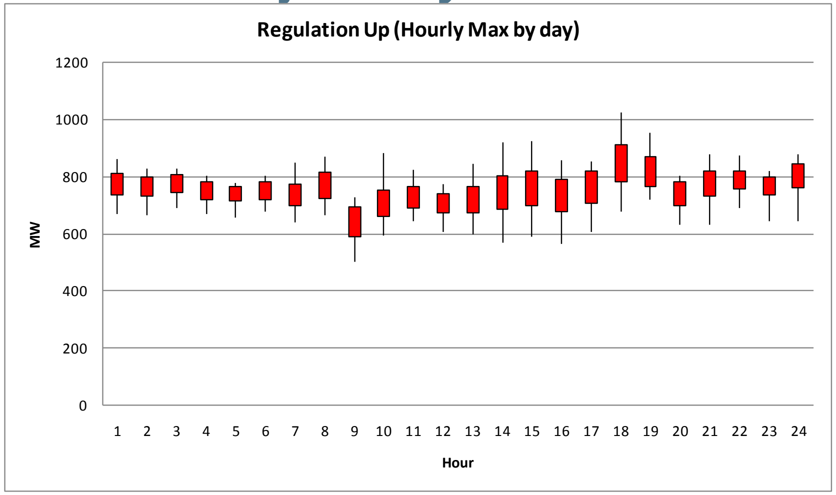


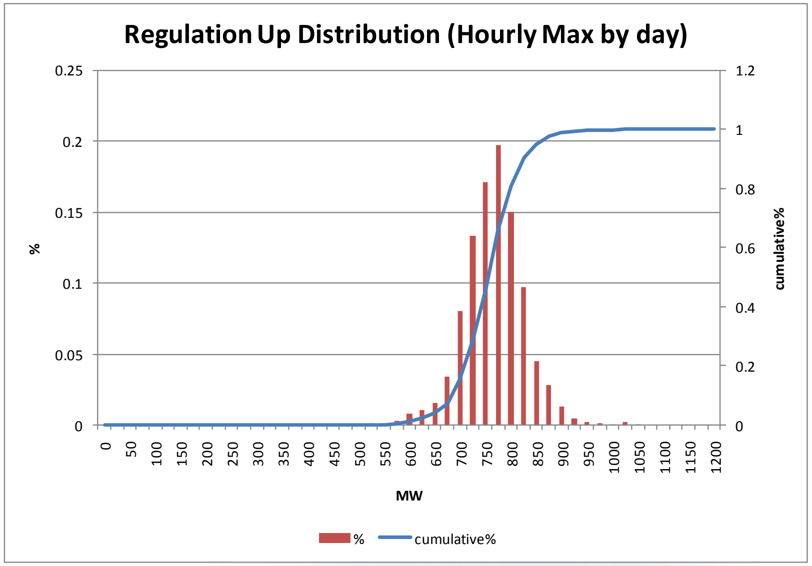
Comparison of regulation requirements using new and previous forecast error. Higher regulation requirement reflects 2010 actual T-7.5 forecast error high then 2006 assumption.



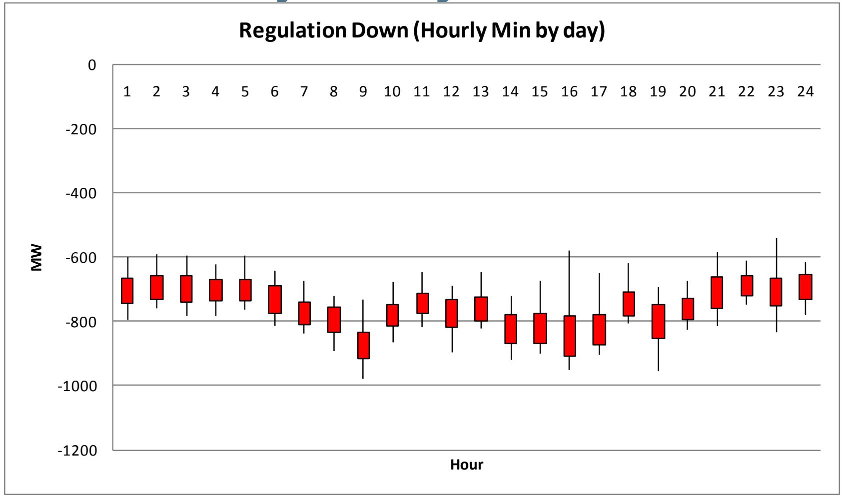


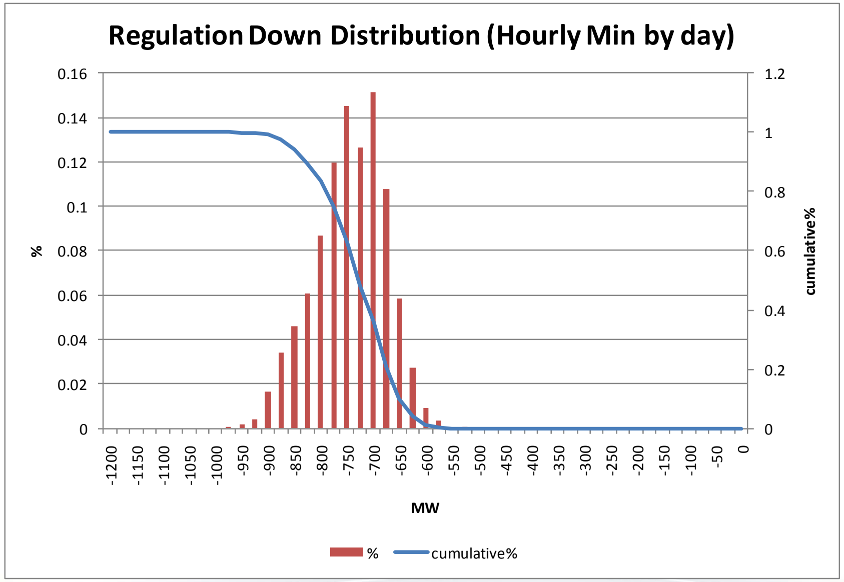
Summer 2020 regulation up capacity requirement – distributions of – 33% Trajectory



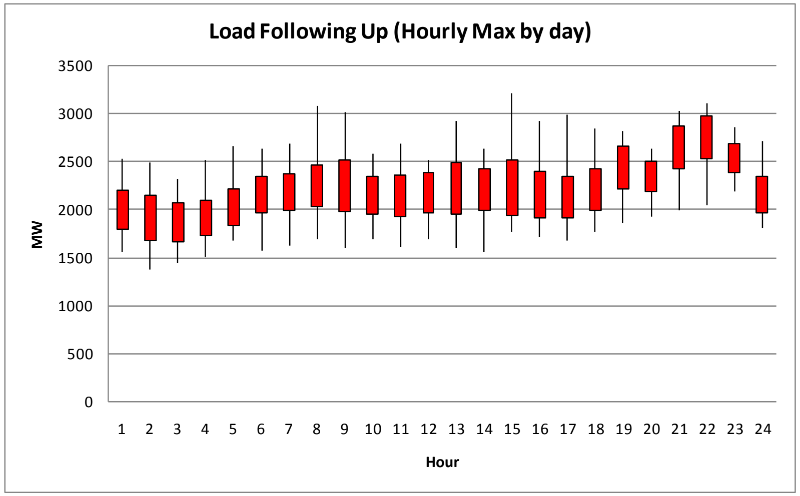


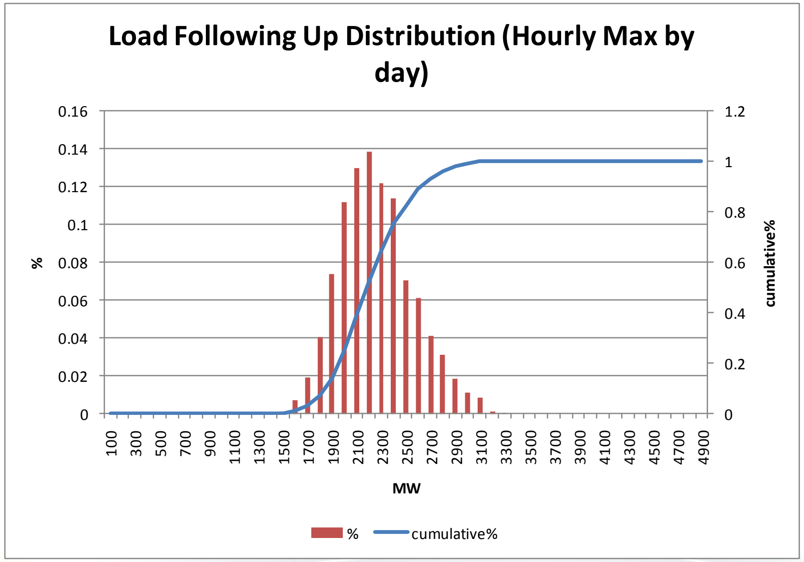
Summer 2020 regulation down capacity requirement – distributions of – 33% Trajectory





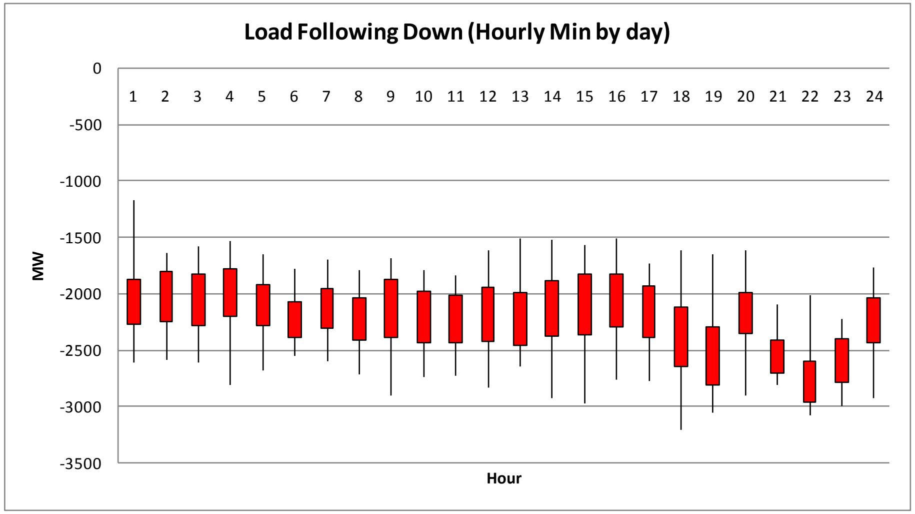
Summer 2020 load following up capacity requirement – distributions of – 33% Trajectory

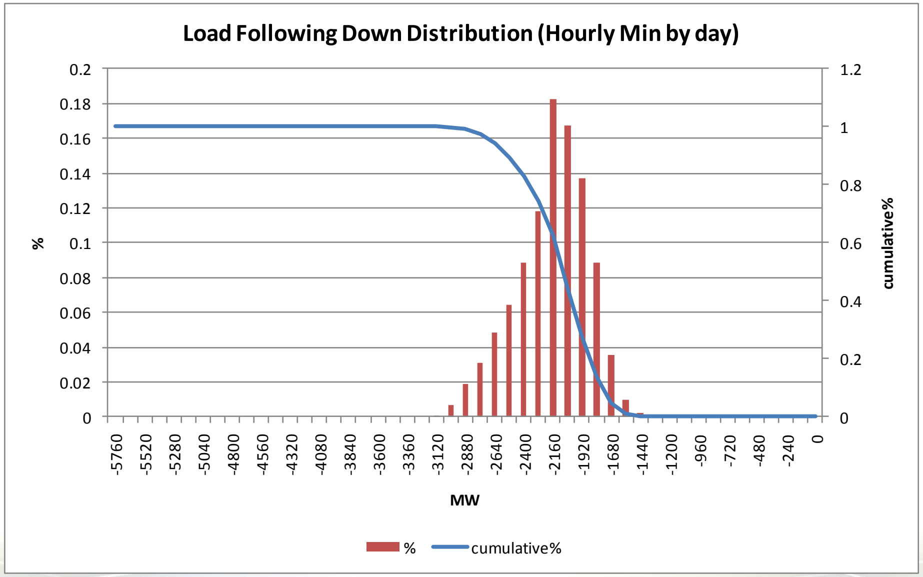




California ISO
Shaping a Renewed Future

Summer 2020 load following down capacity requirement – distributions of – 33% Trajectory





SECTION 3:
PRODUCTION SIMULATION RESULTS FOR TRAJECTORY, ENVIRONMENTAL CONSTRAINED, COST CONSTRAINED AND TIME CONSTRAINED (STEP 2)

Initial comments on method and results

- The focus of the presentation is on initial results for four scenarios:
  - Trajectory, Environmental Constrained, Cost Constrained and Time Constrained
  - Review of these results continues to be conducted
- Results are function of assumptions load, renewable portfolio and forecast error which warrant sensitivity analysis
  - E.g., what range of operational requirements to model and how to interpret the implications
- Some results are a function of *ex post* processing of model outputs; alternative methods will yield different results within a range
  - E.g, allocation of import production costs to California load

Key common assumptions for production simulation cases

- WECC-wide model using latest PC0 dataset from the Transmission Expansion Planning Policy Committee (TEPPC) at WECC
- CPUC 2010-LTPP scenarios (renewable portfolios, load forecasts, planned retirements/additions)
- Conventional dispatchable generation modeled with generic physical operating parameters
  - Inventory of operational flexibility capability – load following, regulating ranges – reviewed in Section 4
- Import constraints enforced
- Path 26 and SCIT constraints enforced
- Out of state renewables:
  - 15% dynamic - 15% intra-hour (15 minute),
  - 40% hourly scheduled - 30% unbundled RECs where

Renewable portfolios for 2020: 2010 LTPP Scenarios

Scenario	Region	Incremental Capacity (MW)							
		Biomass/ Biogas	Geothermal	Small Hydro	Solar PV	Distributed Solar	Solar Thermal	Wind	Total
Trajectory	CREZ-North CA	3	0	0	900	0	0	1,205	**2,108**
	CREZ-South CA	30	667	0	2,344	0	3,069	3,830	**9,940**
	Out-of-State	34	154	16	340	0	400	4,149	**5,093**
	Non-CREZ	271	0	0	283	1,052	520	0	**2,126**
	Scenario Total	338	821	16	3,867	1,052	3,989	9,184	**19,266**
Environmentally Constrained	CREZ-North CA	25	0	0	1,700	0	0	375	**2,100**
	CREZ-South CA	158	240	0	565	0	922	4,051	**5,935**
	Out-of-State	222	270	132	340	0	400	1,454	**2,818**
	Non-CREZ	399	0	0	50	9,077	150	0	**9,676**
	Scenario Total	804	510	132	2,655	9,077	1,472	5,880	**20,530**
Cost Constrained	CREZ-North CA	0	22	0	900	0	0	378	**1,300**
	CREZ-South CA	60	776	0	599	0	1,129	4,569	**7,133**
	Out-of-State	202	202	14	340	0	400	5,639	**6,798**
	Non-CREZ	399	0	0	50	1,052	150	611	**2,263**
	Scenario Total	661	1,000	14	1,889	1,052	1,679	11,198	**17,493**
Time Constrained	CREZ-North CA	22	0	0	900	0	0	78	**1,000**
	CREZ-South CA	94	0	0	1,593	0	934	4,206	**6,826**
	Out-of-State	177	158	223	340	0	400	7,276	**8,574**
	Non-CREZ	268	0	0	50	2,322	150	611	**3,402**
	Scenario Total	560	158	223	2,883	2,322	1,484	12,171	**19,802**

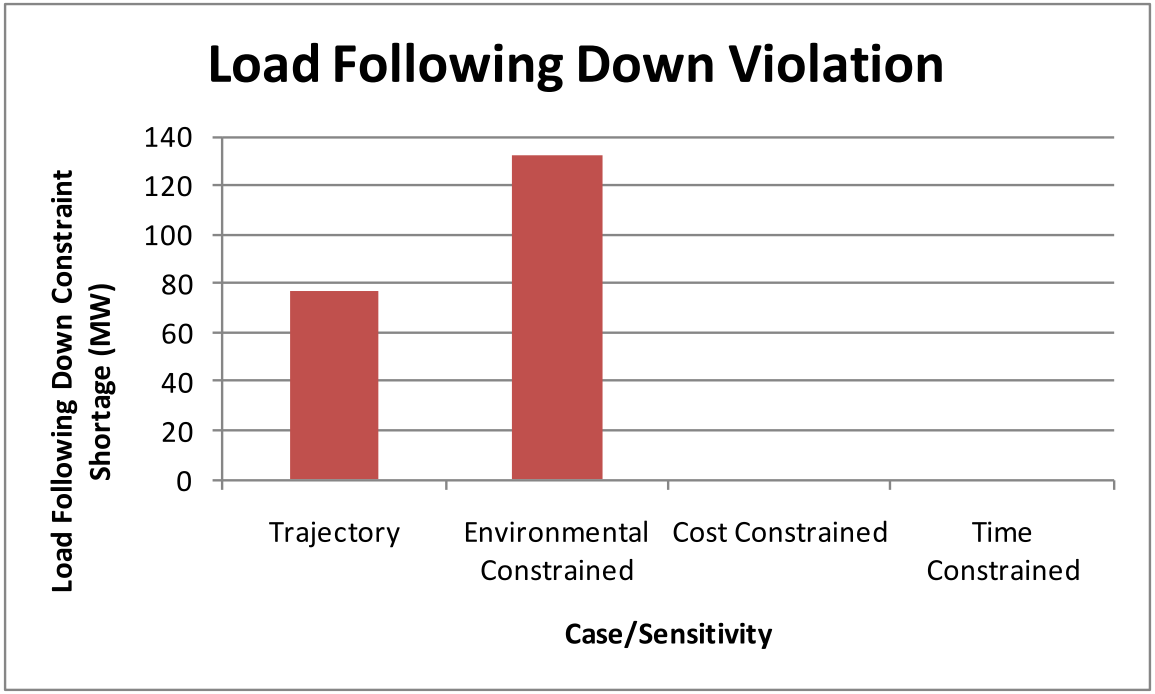
Production simulation results in this section reflect certain assumptions

- Intra-hourly operational needs from Step 1 assume monthly maximum requirements for each hour
  - Regulation, load-following
- Additional resources are added by the model to resolve operational constraints (ramp, ancillary services); this process determines potential need.
- Renewable resources located outside California to serve California RPS will create costs that will be paid for by California load-serving entities – see Step 3 results completed by California IOUs

The analysis adds resources above the defined case resource level to resolve to resolve operational violations

- LTPP analysis did not require adding any generic units to meet PRM because CPUC scoping memo assumptions create a 2020 base dataset that has a significant amount of capacity above PRM
- Next slide shows operational requirement shortages (constraint violations)
- Results for production costs, fuel use and emissions by scenario assume that these resources are added to generation mix

Under CPUC Scoping Memo assumptions, there are no upward constraints violations. There a few hours of load following down constraint violations. (Updated with revised outage profile)



Notes:

1. Consideration of other measures including curtailment should be considered to address load following down shortages
2. Based on limited hours and magnitude of load following down violations the traditional practice of adding generic proxy resources to relieve violation is NOT reflective of needs. However to relieve downward violations, 200MW, 300MW, 0MW and 0MW were introduced in simulations, for the respective trajectory, environmental, cost and time constrained cases

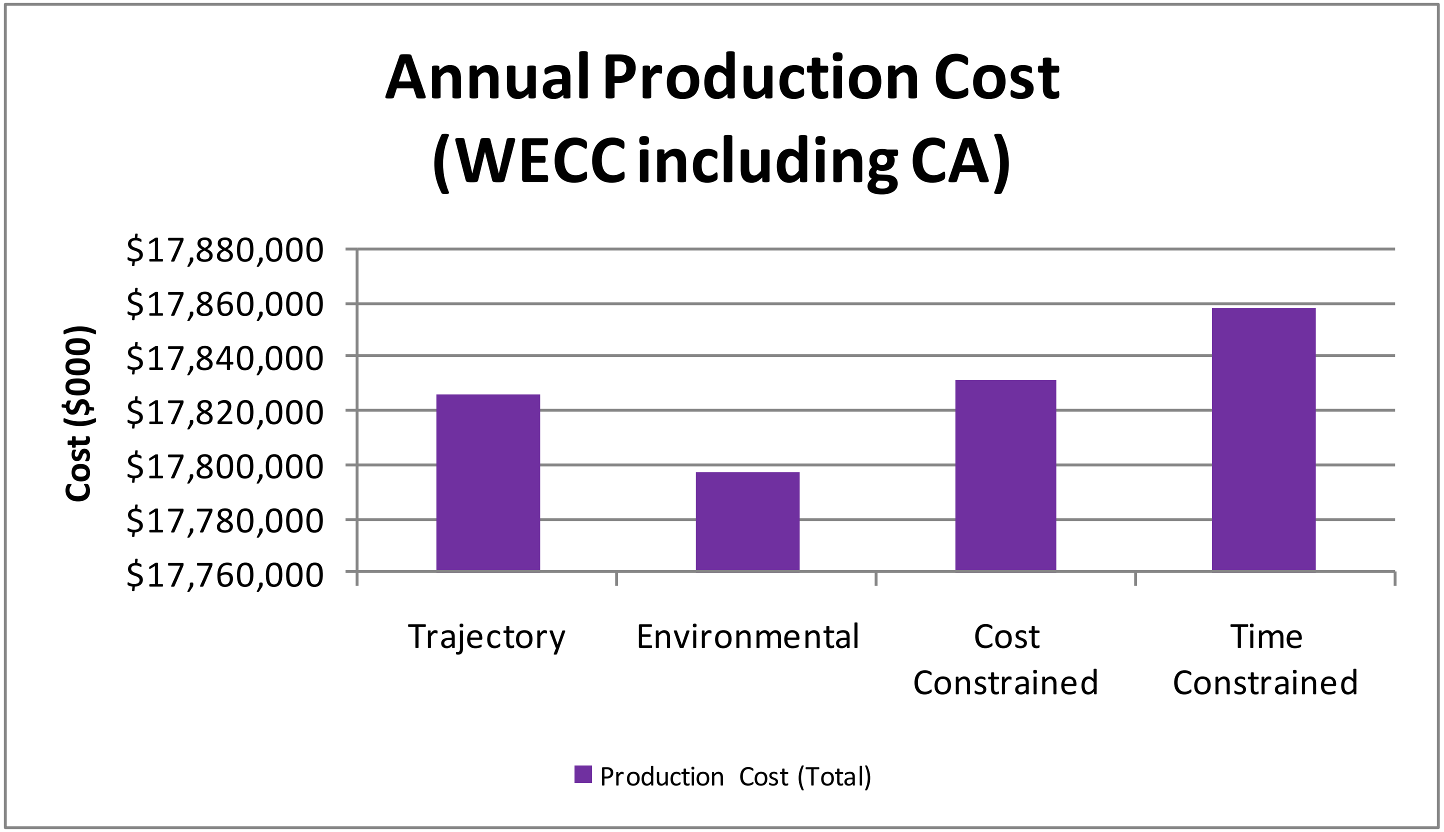
Discussion of results on additional resources

- No upward violations identified in the 2010 Trajectory, Environmental, Cost Constrained and Time Constrained scenarios due to combination of lower loads and reduced requirements
- Limited number of hours and magnitude of load following down violations warrant curtailment or other measures to resolve
- Results are sensitive to assumptions about load level, requirements based on forecast error, mix of resources, and maintenance schedules

Production costs and fuel consumption by scenario

- Production costs based primarily on generator heat rates and assumptions about fuel prices in 2020
- Trends in production costs related to fuel burn and variable O&M (VOM) costs are thus closely related
- Production costs have to be assigned to consuming regions by tracking imports and exports
- Costs associated with emission are tracked separately from fuel and VOM costs

Annual production costs ($) for California and rest of WECC by scenario



Notes:
1. Note scale differences are small
2. Values are in 2010$

Components for calculating California production costs

CA GENERATION COSTS

+

(**CA IMPORTS** – **CA EXPORTS**)

CA IMPORTS

- Dedicated Resources
  - Renewables
    - Firmed
    - Non-Firmed
  - Conventional Resources
    - i.e. Hoover, Palo Verde
- Undesignated (or non-dedicated) Resources
  - Marginal resources in various regions

CA EXPORTS

- Undesignated (or non-dedicated) Resources
  - Marginal resources within CA regions

Calculating total California production costs

+ CA Generation Costs

- Costs to operate CA units (fuel, VOM, start costs)

+ Cost of Imported Power (into CA)

- Dedicated Import Costs
- Undesignated (or non-dedicated) Import Costs
- Out of State renewables (zero production cost)

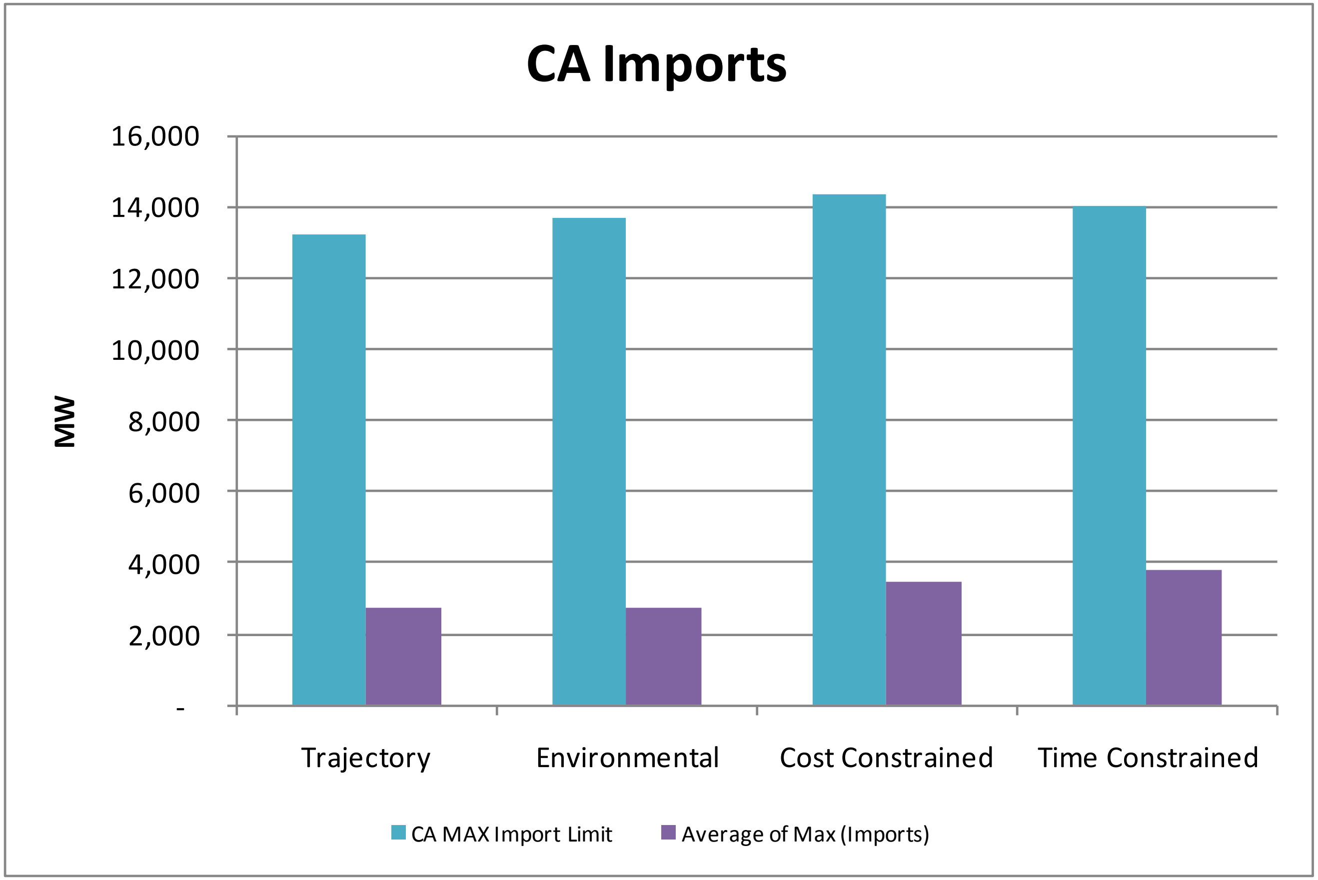
– Cost of Exported Power (out of CA)

- Undesignated (or non-dedicated) Export Costs

= Total Production Cost of meeting CA load

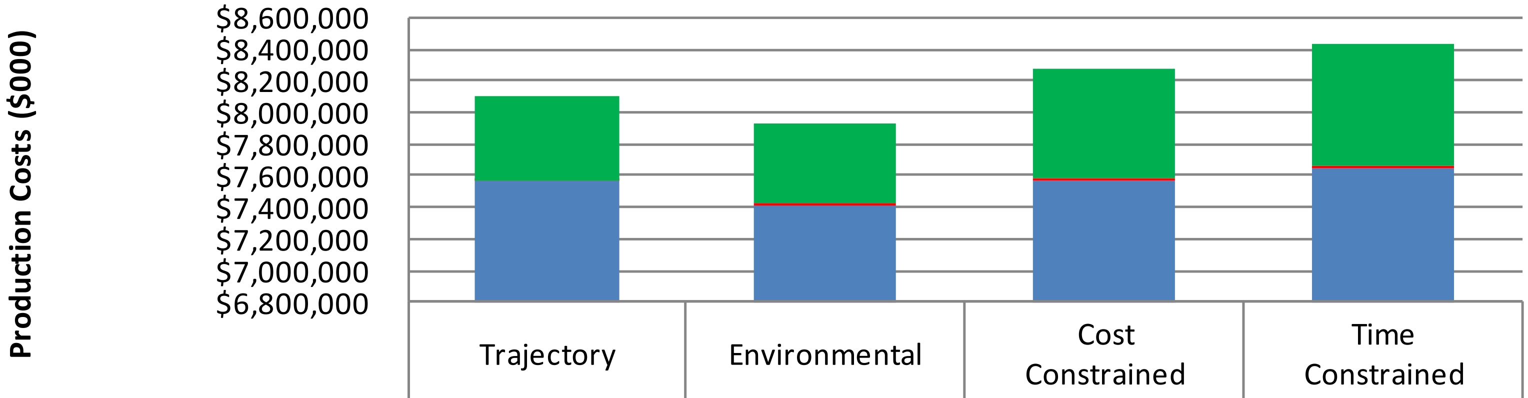
Note: Dedicated vs. Non-dedicated may also be known as specified or non-specified

Net Import results by scenario



Total annual production costs ($) associated with California load (accounting for import/exports), by scenario

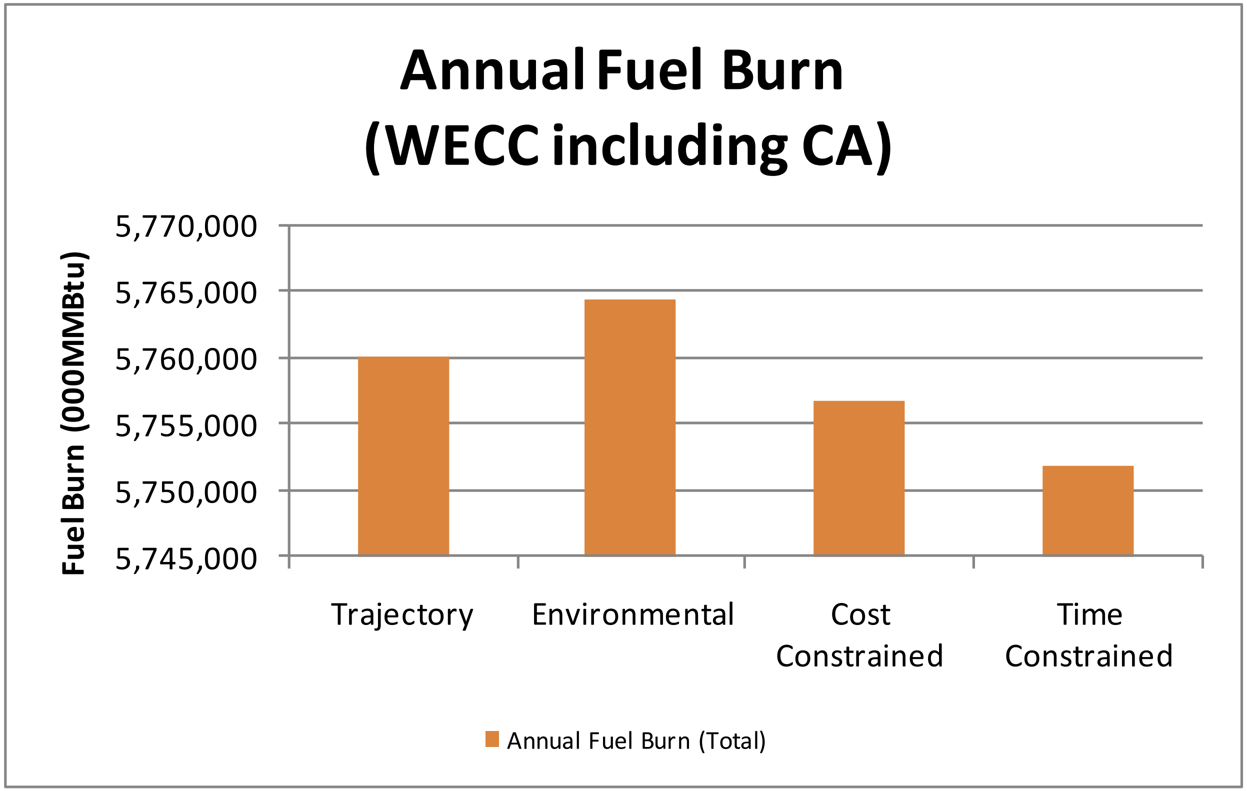
Production Costs to Meet CA Load Accounting for Imports / Exports



	Trajectory	Environmental	Cost Constrained	Time Constrained
Non-Dedicated	$529,620	$511,919	$698,702	$769,998
Dedicated	$9,195	$12,055	$9,649	$21,864
CA Generation Prod Costs	$7,566,554	$7,408,596	$7,570,102	$7,644,021

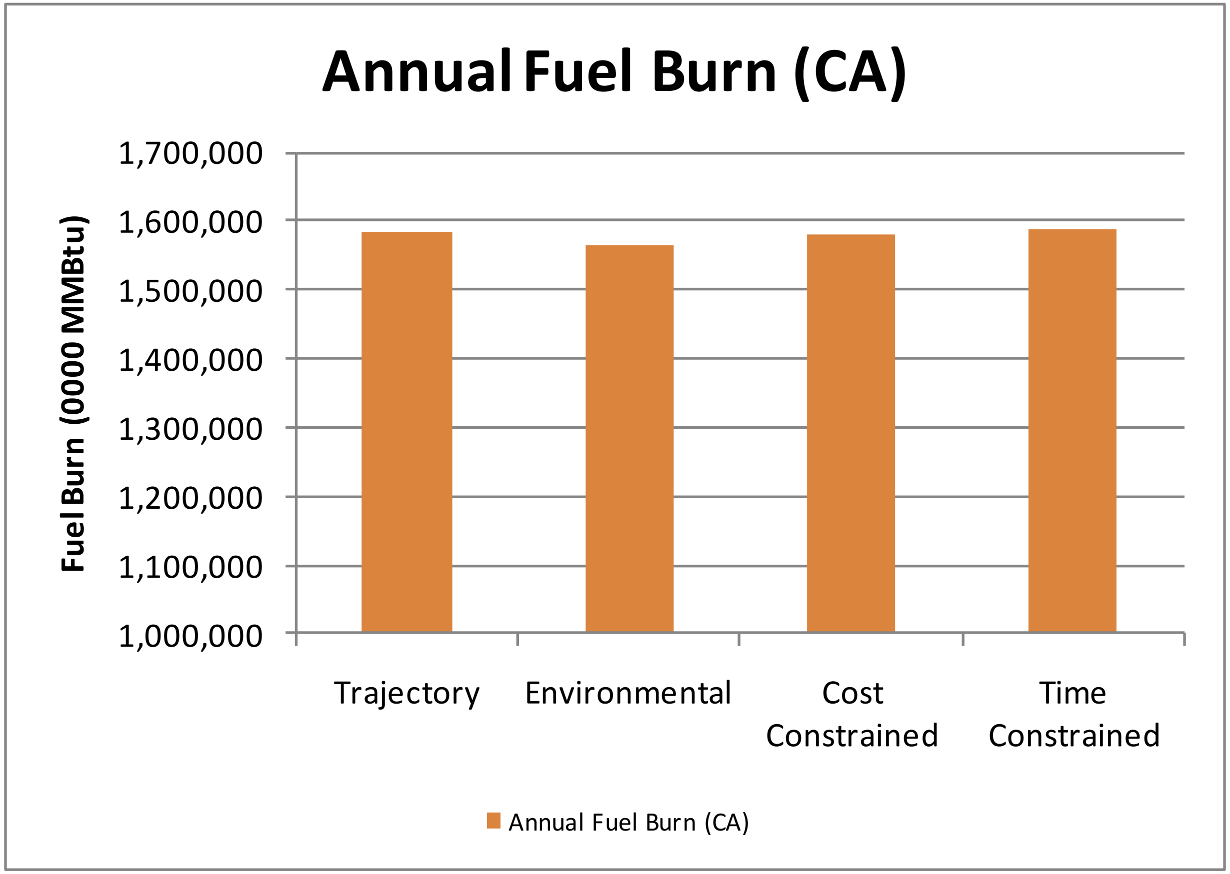
Note: IOUs have a step 3 accounting. This slide reflect vintage method for accounting imports/exports. Energy credit for RECs is not accounted for in this. When the IOU do their Step 3 analysis this will be accounted for.

Total WECC (including CA) fuel burn (MMBTU), by scenario



MMBTU = million BTU for conventional/fossil resources

Total fuel burn (MMBTU) for in-state generation in California, by scenario



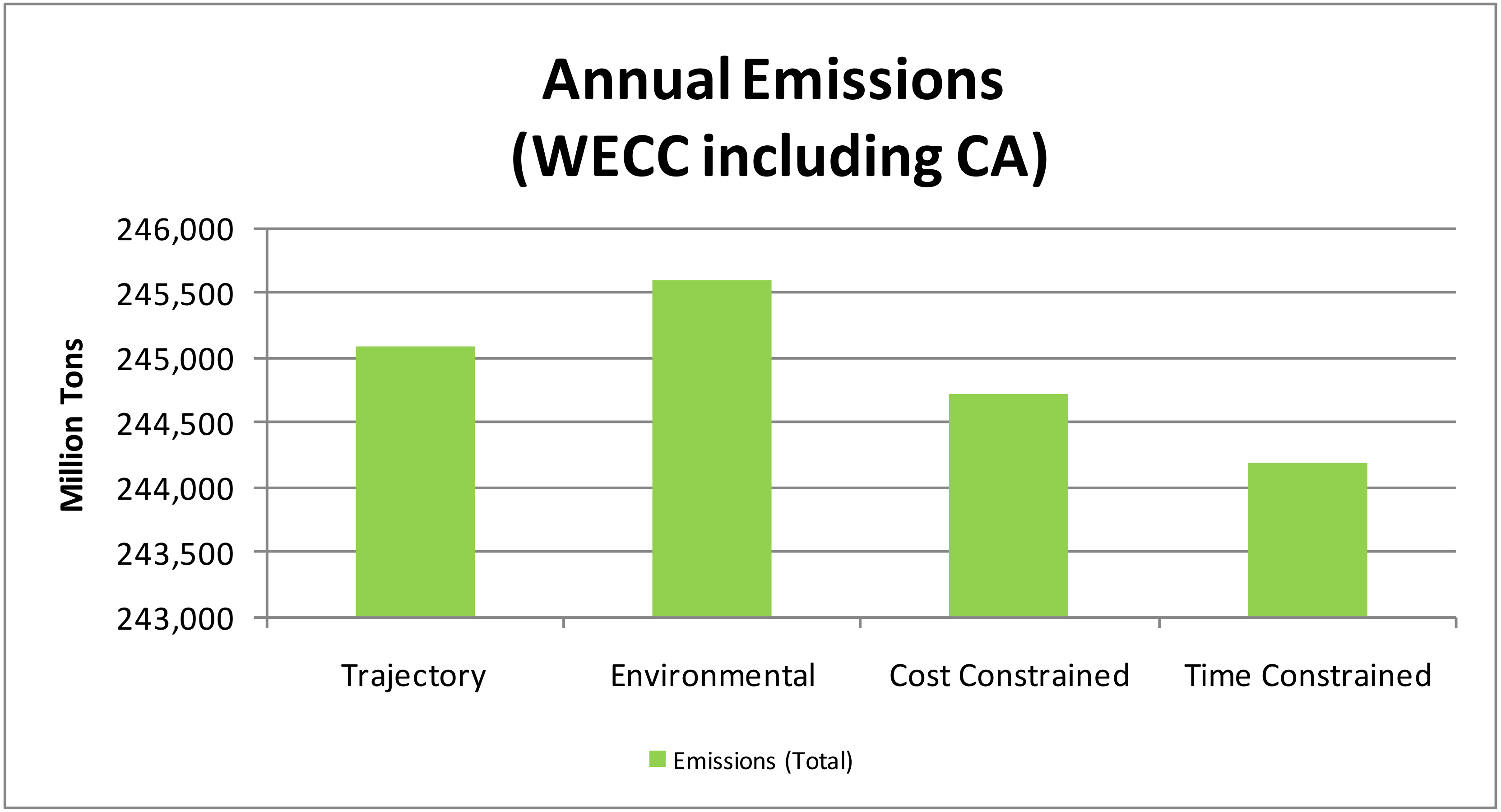
MMBTU = million BTU for conventional/fossil resources

GHG emissions calculations

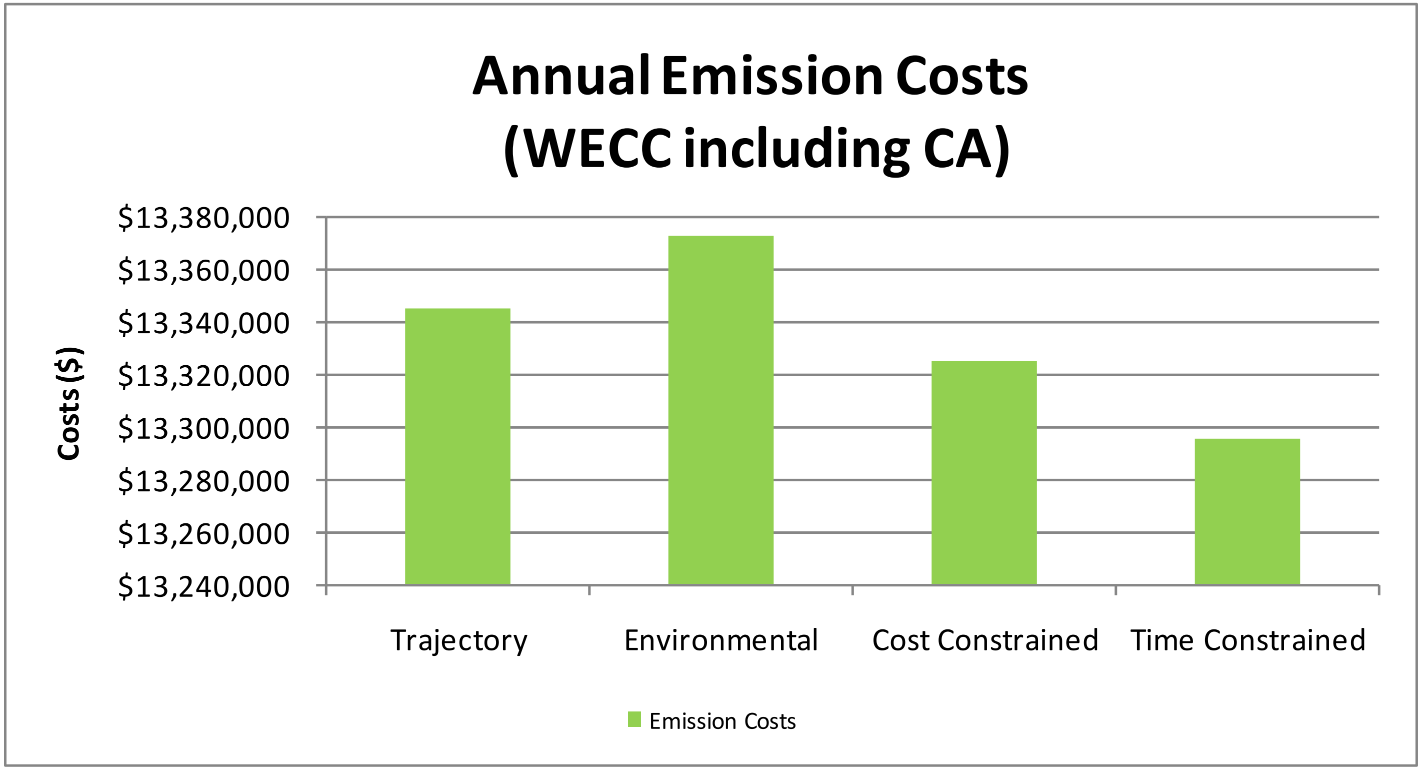
- GHG emissions are calculated by heat rate (MMBTU/MWh) × fixed emissions factor (lbs/MMBTU)
- Plants with multiple-step heat rate curves will have different emissions/MWh depending on their output in each hour of the simulation (two actual plants in table below)

Supply curve:		Segment 1	Segment 2	Segment 3
Plant 1	MW	68	170	340
	Heat rate	11750	10100	9600
Plant 2	MW	263	394	525
	Heat rate	8000	7300	7000

Annual WECC emissions by scenario



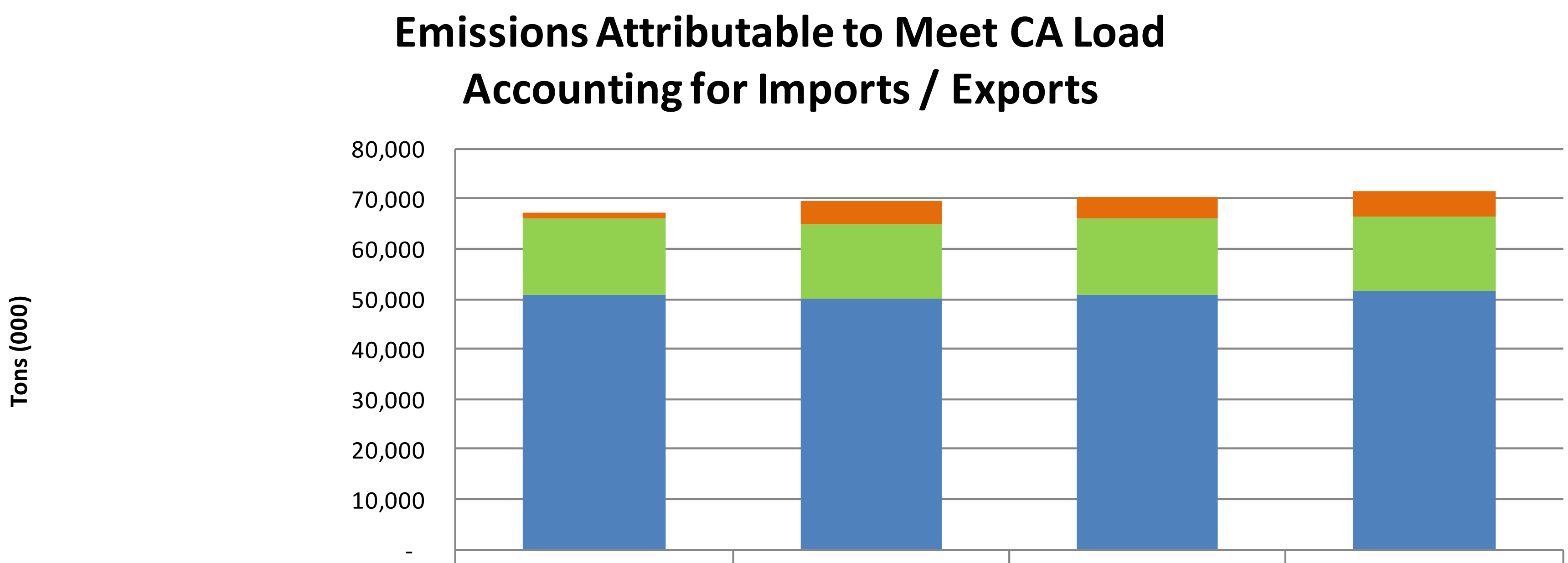
Annual WECC emission costs by scenario



Calculation of emissions associated with California

- Production simulation modeling output includes GHG emissions (tons/MMBTU) per generator to capture WECC-wide emissions reductions, but:
  - The model solves for the WECC without considering contractual resources specifically dedicated to meet California load
  - Not all OOS RPS energy dedicated to CA may “flow” into CA for every simulated hour as it could in actual operations (thus reducing emissions in CA)
- To ensure that the emissions benefit of OOS RPS energy dedicated to California is counted towards meeting California load, the study uses an *ex post* emissions accounting method (next slide)

Emissions attributed to meet California load (accounting for Import/Exports[1]), by scenario and emissions source



	Trajectory	Environmental	Cost Constrained	Time Constrained
Emissions from Non-Dedicated Import	1,464	4,696	4,471	5,223
Emissions from Dedicatied Imports	14,932	14,923	14,897	14,929
CA Emissions	51,013	49,912	51,035	51,561

1. Emissions associated with non-specified imports are attributed to CA based on an assumed emissions rate of .44 metric tons/MWh

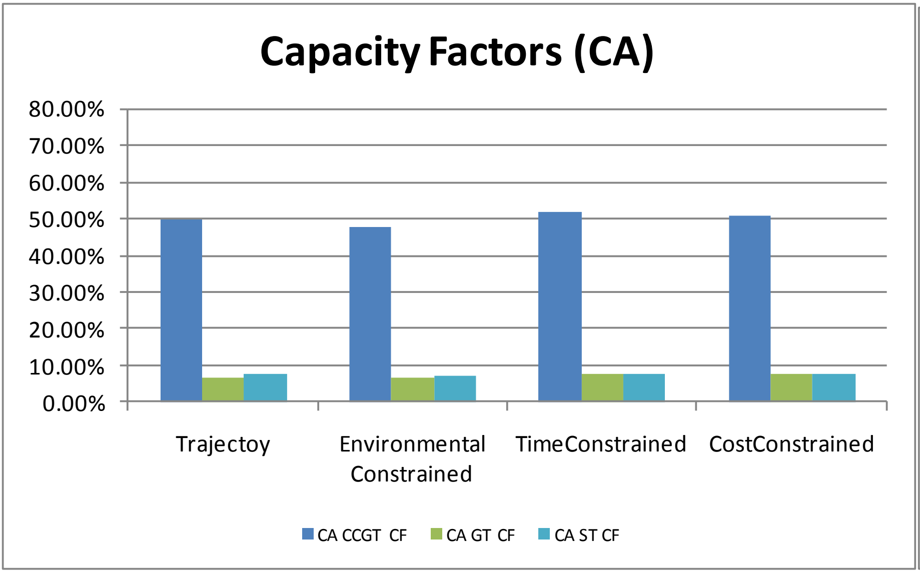
Discussion of emissions results

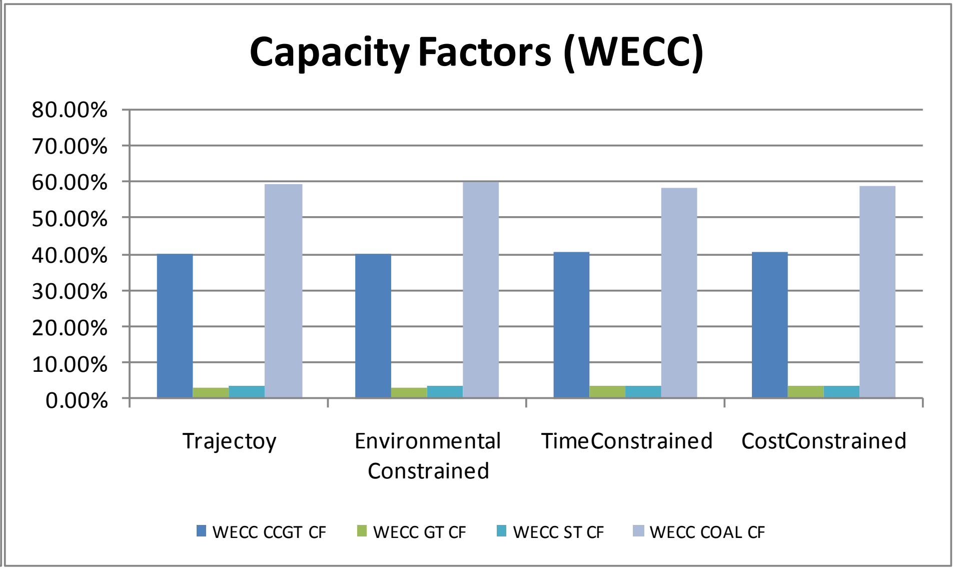
- Total emissions reduction assigned to California includes contribution of imports
- Emissions impact from California in-state generation is due in part to operational requirements associated with integration
  - Total emissions from California generators are lower in the sensitivity analysis on operational requirements discussed in Section 3
- Results are sensitive to method for allocating renewable energy imports to California load

Changes to fleet operations

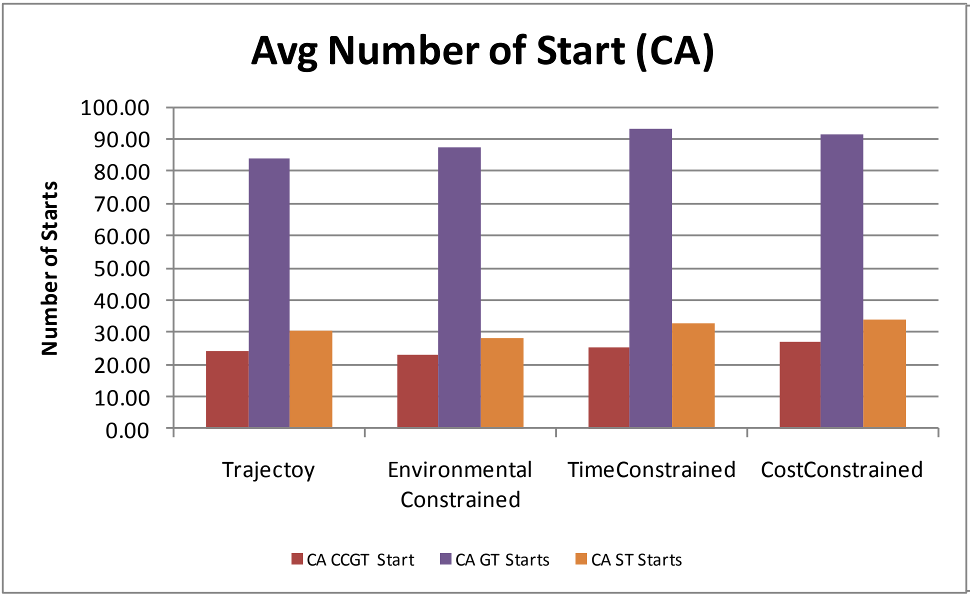
- Changes in capacity factors, number of starts by unit type and location
- California within-state results are influenced by integration requirements within state
- Linked to production costs and emissions, as shown in earlier slides

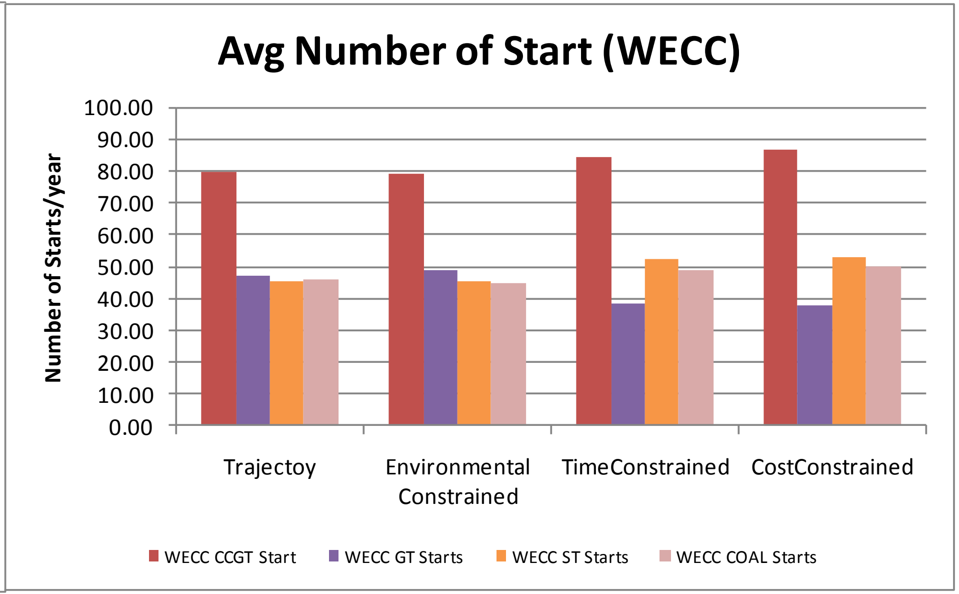
Changes to Capacity Factors, by scenario





Changes to number of Start-ups, by scenario





Comparison of CA and WECC (exclusive of CA) Results (2)

Comparison of Dispatchable Resources (CA versus WECC) (Trajectory)

Technology	CA		WECC		Difference (CA-WECC)	
	Avg CF	Avg Unit S	Avg CF	Avg Unit S	Avg CF	Avg Unit Starts
CCGT	49.71%	24.00	40.19%	79.69	9.52%	-55.69
Coal	N/A	N/A	59.14%	45.92	N/A	N/A
GT	6.86%	84.23	3.07%	47.35	3.79%	36.88
ST	7.47%	30.69	3.57%	45.28	3.90%	-14.59

Comparison of Dispatchable Resources (CA versus WECC) (Environmental Constrained)

Technology	CA		WECC (Excl CA)		Diff(CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	47.82%	22.72	40.18%	79.29	7.64%	-56.57
Coal	N/A	N/A	59.58%	44.71	N/A	N/A
GT	6.67%	87.59	3.06%	48.83	3.61%	38.76
ST	7.37%	28.00	3.56%	45.51	3.81%	-17.51

Comparison of Dispatchable Resources (CA versus WECC) (Time Constrained)

Technology	CA		WECC (Excl CA)		Diff (CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	51.60%	25.56	40.70%	84.34	10.90%	-58.79
Coal	N/A	N/A	58.40%	48.77	N/A	N/A
GT	7.63%	92.89	3.35%	38.49	4.28%	54.40
ST	7.51%	33.00	3.74%	52.06	3.77%	-19.06

Comparison of Dispatchable Resources (CA versus WECC) (Cost Constrained)

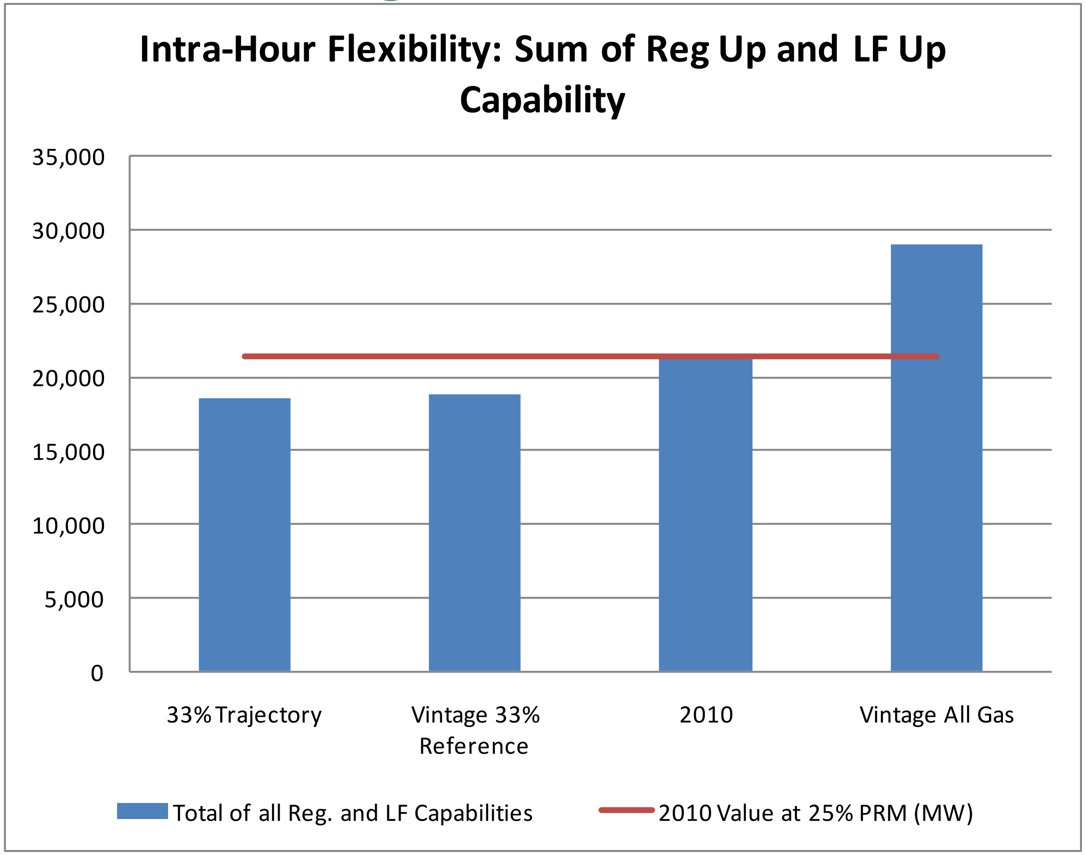
Technology	CA		WECC (Excl CA)		Diff (CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	50.78%	27.07	40.59%	86.43	10.19%	-59.35
Coal	N/A	N/A	58.90%	50.30	N/A	N/A
GT	7.72%	91.39	3.42%	37.82	4.30%	53.58
ST	7.64%	34.00	3.82%	52.99	3.82%	-18.99

SECTION 4:
FURTHER ANALYSIS OF FLEET FLEXIBILTY IN 2020

Analysis of generation fleet flexibility in 2020

- Prior presentations provided analysis of fleet flexibility
- Updated fleet flexibility analysis for 2010-CPUC LTPP trajectory scenario
- The following compares the fleet flexibility with vintage “33% reference” and “all gas” cases as well as 2010 existing

Analysis of generation fleet flexibility in 2020, with comparison with vintage cases and 2010



- The blue bar reflects the fleet flexibility of the resource fleet in the trajectory case and fleet to meet PRM in the vintage cases
- Fleet flexibility decreases as OTC resources are replaced by renewables

SECTION 5:
RECOMMENDATIONS AND NEXT STEPS

Preliminary observations

- Assuming CA achieves demand side objectives preliminary results indicate most operational requirements can be satisfied with potential need for measures to address some over-generation conditions
- Operational requirements are dependent on load, wind and solar forecast error assumptions, mix of renewable resources and outages
  - Initial sensitivities using vintage regulation and higher load following requirements indicate potential for shortages including load following up

Recommendations and next steps

- Recommend updating analysis in future years as assumptions evolve and more is known
- Continue to evaluate forecast error with actual data as additional data is available
- Recommend running additional sensitivities to:
  - Assess higher loads
  - Assess changes to forecast error and requirements
  - Evaluate generation outages
  - Assess resources needed for local capacity requirements
  - Additional evaluation storage, pump hydro and demand response
  - Assess different assumptions of dynamic transfers

APPENDIX:
PRODUCTION SIMULATION MODEL CHANGES

Overview of Step 2 Database and Modeling

- To conduct the LTPP Step 2 analysis, an up-to-date PLEXOS database was required
- ISO used the 33% operational study PLEXOS database as a starting point
- Input data from this database were changed to align with the assumptions in the CPUC scoping memo
- Non-specified assumptions were updated by the ISO to reflect operational feasibility and to include the best publically available data
- To ensure the April 29th deadline was met, PLEXOS implemented several modeling enhancements to improve simulation efficiency

Key Inputs

- Two sets of key inputs: CPUC specified assumptions and non-specified assumptions updated by the ISO
- Assumptions stated in the CPUC Scoping Memo
  - Load forecast that includes demand side reductions
  - Renewable resource build-out
  - Existing, planned and retiring generation
  - Maximum import capability to California
  - Gas price methodology for California
  - CO_2 price assumption
- Non-specified assumptions updated by the ISO
  - Allocation of reserve requirements between ISO and munis
  - Generator operating characteristics and profiles
  - Operational intertie limits
  - Loads, resources, transmission and fuel prices outside of California

California ISO
Shaping a Renewed Future

CPUC SPECIFIED ASSUMPTIONS

Load – Load Profiles

- Nexant created a load profile that was consistent with the CPUC's forecasted load for the analysis of the four LTPP scenarios
- Load profile adjustment made to the CPUC specified demand side resources
  - Energy efficiency
  - Demand side CHP
  - Behind-the-meter PV – modeled as supply
  - Non-event based DR

Generation - CPUC Generation Dataset

- CPUC provided data on existing, planned and retiring generation facilities
- Existing resources specified by the CPUC were drawn from two resources:
  - 2011 NQC as of August 2^{nd}, 2010
  - ISO master generation list
- Additions and non-OTC retirements are drawn from the ISO OTC scenario analysis tool; other additions are resources with CPUC approved contracts that do not have AFC permits approved
  - CCGTs in CPUC planned additions were modeled with generic unit operating characteristics taken from the MPR
- OTC retirements taken from the State Water Board adopted policy with several CPUC modifications

CPUC Supply Side CHP and DR Specifications

- Existing CHP and DR bundles in the 33% operational study PLEXOS database were scaled to match the incremental supply side CHP and DR goals in the CPUC scoping memo
- 761 MW of incremental supply side CHP was assumed to be online in 2020 with a heat rate of 8,893 Btu/kWh per the CPUC scoping memo
- 4,817 MW of incremental DR was modeled as supply in 2020 (including line losses)
  – Non-event based DR was included in the load profiles and not in the Step 2 database as supply side resource

Load and Resource Balance with CPUC assumptions

- The CPUC Scoping Memo assumptions estimate a 17,513 MW surplus above PRM in 2020 in the ISO

Load and Resource Balance in the ISO using CPUC Resource Assumptions (MW)										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
ISO Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	(3,432)	(4,712)	(5,650)	(6,374)	(7,187)	(8,036)	(8,936)	(9,874)	(10,776)	(11,651)
Net ISO Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,747	4,388	6,728	7,336	10,558	11,280	12,207	12,283	13,471	13,547
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	69,877	72,353	74,693	74,292	75,254	75,024	71,219	70,344	70,581	68,580
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus	**16,395**	**19,480**	**22,010**	**21,748**	**22,924**	**22,936**	**19,376**	**18,827**	**19,340**	**17,513**

Updating Generation Data in 33% Operational Database

- **The generation data in the 33% operational database were updated to reflect the specified existing, planned and retiring facilities in the CPUC scoping memo**
- **ISO also solicited feedback from the working group, stakeholders via market ISO market notice and also all parties on the LTPP service list on generator operating characteristics which was incorporated into the Step 2 database**
- **ISO found some discrepancies in the CPUC generation assumptions which it has corrected in its Step 2 database and accounting:**
  - Double-counting of the Ocotillo facility
  - Renewable resource capacity additions above what is chosen in the 33% RPS calculator
  - Double counting of several resources as both imports and resources

Ocotillo/Sentinel Generation

- CPUC scoping memo includes two separate facilities in its planned additions for Ocotillo (455 MW) and Sentinel (850 MW)
- Ocotillo is a subset of the Sentinel facility (units 1-5)
  - SCE signed a contract with Sentinel for an additional three units in 2008
- ISO Step 2 database only includes eight Sentinel units (850 MW) because Ocotillo (455 MW) is already accounted for in Sentinel's nameplate capacity

RPS Resources above 33%

- CPUC included 287 MW of RPS resources in its planned additions that are not included in the 33% RPS scenarios:
  - CalRENEW-1(A) (5 MW)
  - Copper Mountain Solar 1 PseudoTie-pilot (48 MW)
  - Vaca-Dixon Solar Station (2 MW)
  - Blythe Solar 1 Project (21 MW)
  - Calabasas Gas to Energy Facility (14 MW)
  - Chino RT Solar Project (2 MW)
  - Chiquita Canyon Landfill (9 MW)
  - Rialto RT Solar (2 MW)
  - Santa Cruz Landfill G-T-E Facility (1 MW)
  - Sierra Solar Generating Station (9 MW)
  - Celerity I (15 MW)
  - Black Rock Geothermal (159 MW)
- If included, these resources will create RPS scenarios that are above 33% RPS
- These resources were not profiled in the Step 1 analysis
- ISO did not include these resources in the Step 2 database

Existing Generation/Imports Discrepancies

- The 2011 NQC list includes 2,626 MW of resources that are imports to the ISO
  - APEX_2_MIRDYN (505 MW)
  - MRCHNT_2_MELDYN (439 MW)
  - MSQUIT_5_SERDYN (1,182 MW)
  - SUTTER_2_PL1X3 (500 MW)
- The CPUC's original L&R tables counted the capacity of these resources twice:
  1. Directly, as specified resources with NQC capacity
  2. Indirectly, by assuming full transmission capability into the ISO
- For accounting purposes and to avoid double accounting, ISO has removed these resources from the available generation but maintains the assumption of full transmission capability into the ISO

Load and Resource Balance After Assumption Modifications

- Accounting for all of these modifications, the load and resource balance has a surplus of 14,144 MW above PRM in 2020, compared to 17,513 MW above PRM using the CPUC assumptions

Load and Resource Balance in the ISO using CAISO Resource Modifications (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	3,432	4,712	5,650	6,374	7,187	8,036	8,936	9,874	10,776	11,651
Net Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,618	4,259	6,440	7,048	9,815	10,537	11,464	11,540	12,728	12,804
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	67,122	69,598	71,779	71,378	71,885	71,655	67,850	66,975	67,212	65,211
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus Above PRM with CAISO Modifications	13,640	16,726	19,096	18,834	19,556	19,568	16,007	15,459	15,972	14,144
Surplus Above PRM with CPUC Assumptions	16,395	19,480	22,010	21,748	22,924	22,936	19,376	18,827	19,340	17,513
Difference in Surplus between CPUC and CAISO	***2,755***	***2,755***	***2,914***	***2,914***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***

MPR Gas Forecast Methodology

- CPUC Scoping Memo specifies that the LTPP proceeding use a gas forecast calculated using the same methodology as the Market Price Referent (MPR) using NYMEX data gathered from 7/26/2010 – 8/24/2010
  - MPR methodology provides a transparent framework to derive a forecast of natural gas prices at the utility burner-tip in California
  - In the near term (before 2023), the forecast is based on:
    1. NYMEX contract data for natural gas prices at Henry Hub and basis point differentials between HH and CA
    2. A municipal surcharge, calculated as a percentage of the commodity cost
    3. A gas transportation cost based on the tariffs paid by electric generators

CA Gas Forecast

- 2020 natural gas forecast for CA delivery points (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - PGE_Citygate	$ 5.95	$ 5.92	$ 5.75	$ 5.31	$ 5.29	$ 5.34	$ 5.41	$ 5.45	$ 5.47	$ 5.54	$ 5.79	$ 6.04
Gas - PGE_Citygate_BB	$ 6.07	$ 6.04	$ 5.87	$ 5.43	$ 5.41	$ 5.46	$ 5.53	$ 5.57	$ 5.59	$ 5.66	$ 5.92	$ 6.17
Gas - PGE_Citygate_LT	$ 6.23	$ 6.20	$ 6.03	$ 5.59	$ 5.57	$ 5.62	$ 5.69	$ 5.73	$ 5.75	$ 5.82	$ 6.08	$ 6.33
Gas - SoCal_Border	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - SoCal_Burnertip	$ 6.18	$ 6.15	$ 5.98	$ 5.57	$ 5.54	$ 5.60	$ 5.67	$ 5.71	$ 5.72	$ 5.80	$ 6.02	$ 6.28

CO_2 Price

- A \$36.30/short ton of CO_2 (2010\$) cost was used in the PLEXOS simulations per the CPUC scoping memo

NON-SPECIFIED ASSUMPTIONS UPDATED BY ISO

Allocation of Reserves Between ISO and Munis

- Step 1 analysis created statewide load following and regulation requirements
- Step 2 is an ISO-wide analysis that requires an allocator to split the load following and regulation requirements between the IOUs and Munis
- Allocator calculated using two parts:
  - 50% of allocator = ratio of peak load between the ISO (83%) and Munis (17%)
  - 50% of allocator = fraction of wind and solar resources delivered to California that are integrated by the ISO (94%) and Munis (6%)
- This results in the following allocation of the reserve requirements: 88.5% to the ISO and 11.5% to the Munis

Update of Generator Operating Characteristics

- ISO received feedback from 5 stakeholders on information in the 33% operational study PLEXOS database
  - Comprehensive list of changes came from SCE and included updated information on individual generator operating characteristics and SP15 hydro dispatch
  - Calpine submitted a new start profile for CCGTs
- CT planned additions and generic units were mapped to the operating characteristics of an LMS100 or LM6000 depending on plant size

Helms modeling

- PG&E updated the maximum capacity of the Helms reservoir to 184.5 GWh
- PG&E provided end of spring reservoir energy storage target and summer monthly energy usage schedules
- ISO consulted with PG&E to develop the appropriate pumping windows in 2020
  – availability in the summer months, Helms pumping was restricted to 1 pump between May and September
  – 3 pumps were assumed to be available for October through April
- Continued discussions with PG&E suggest that three pump capability in 2020 in non-summer months may not be possible; may warrant additional sensitivities

Transmission Import Limits to CA

- ISO defined simultaneous import limits to CA
- ISO used a model developed by the ISO to estimate the Southern California Import Transmission (SCIT) limit based on
  - planned thermal additions
  - OTC retirements
  - renewable resources additions
  - neighboring transmission path flows into and around the SCIT area

Import Limits by Scenario and Time

Transmission Limits (MW)	Summer Pk	Summer Off Pk	Winter Pk	Winter Off Pk
Trajectory Case				
S. Cal Import Limit to be used for study	12,416	10,709	10,928	8,823
Total California Import Limit	13,216	11,509	11,728	9,623
Environmental Case				
S. Cal Import Limit to be used for study	12,901	10,735	11,237	8,851
Total California Import Limit	13,701	11,535	12,037	9,651
Cost Case				
S. Cal Import Limit to be used for study	13,523	10,735	11,726	8,851
Total California Import Limit	14,323	11,535	12,526	9,651
Time Case				
S. Cal Import Limit to be used for study	13,221	10,735	11,499	8,851
Total California Import Limit	14,021	11,535	12,299	9,651

Assumptions of Gas Forecast Outside of CA

- The MPR methodology provides a forecast of gas prices for generators inside of California
- In order to avoid skewing the relative competitive position of gas fired generators inside and outside of California, WECC-wide gas prices outside of California must be updated to reflect the same underlying commodity cost of gas embedded in the MPR forecast

Gas Forecast Outside of CA (cont'd)

- Created an MPR-style forecast for gas prices elsewhere in the WECC drawing upon available NYMEX contract data over the same trading period (7/26/10 – 8/24/10):
  - In addition to the California gas hubs (PG&E Citygate and Socal Border), forecast hub prices at Sumas, Permian, San Juan, and Rockies hubs using the NYMEX basis differentials
  - For each bubble (geographic area), add appropriate delivery charges (based on TEPPC delivery charges) to the appropriate hub price to determine the burnertip price
- Two specific changes were made to this methodology based on IOU feedback:
  - Arizona gas hub was moved from Permian to SoCal Border
  - Delivery charge was removed from Sumas hub to British Columbia

Gas Forecast Outside of CA

- 2020 natural gas forecast for delivery points outside of California (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - AECO_C	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - Arizona	$ 6.06	$ 6.02	$ 5.85	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.57	$ 5.58	$ 5.66	$ 5.89	$ 6.16
Gas - Baja	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Colorado	$ 6.08	$ 6.04	$ 5.88	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.56	$ 5.57	$ 5.65	$ 5.92	$ 6.17
Gas - Idaho_Mont	$ 6.00	$ 5.97	$ 5.81	$ 5.23	$ 5.21	$ 5.26	$ 5.33	$ 5.37	$ 5.39	$ 5.46	$ 5.85	$ 6.10
Gas - Kern_River	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Malin	$ 5.98	$ 5.95	$ 5.79	$ 5.10	$ 5.07	$ 5.13	$ 5.20	$ 5.24	$ 5.26	$ 5.33	$ 5.83	$ 6.08
Gas - Pacific_NW	$ 6.11	$ 6.08	$ 5.91	$ 4.98	$ 4.95	$ 5.01	$ 5.08	$ 5.12	$ 5.14	$ 5.21	$ 5.96	$ 6.21
Gas - Permian	$ 5.58	$ 5.54	$ 5.38	$ 5.01	$ 4.99	$ 5.04	$ 5.11	$ 5.15	$ 5.17	$ 5.24	$ 5.42	$ 5.67
Gas - Rocky_Mntn	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - San_Juan	$ 5.52	$ 5.49	$ 5.32	$ 4.86	$ 4.84	$ 4.89	$ 4.96	$ 5.00	$ 5.02	$ 5.09	$ 5.37	$ 5.62
Gas - Sierra_Pacific	$ 6.12	$ 6.08	$ 5.92	$ 5.48	$ 5.46	$ 5.51	$ 5.58	$ 5.62	$ 5.64	$ 5.71	$ 5.96	$ 6.21
Gas - Sumas	$ 6.02	$ 5.98	$ 5.82	$ 4.89	$ 4.86	$ 4.92	$ 4.99	$ 5.03	$ 5.04	$ 5.11	$ 5.86	$ 6.11
Gas - Utah	$ 5.76	$ 5.73	$ 5.56	$ 4.99	$ 4.97	$ 5.02	$ 5.09	$ 5.13	$ 5.15	$ 5.22	$ 5.61	$ 5.86
Gas - Wyoming	$ 6.05	$ 6.01	$ 5.85	$ 5.27	$ 5.25	$ 5.30	$ 5.37	$ 5.41	$ 5.43	$ 5.50	$ 5.89	$ 6.14

TEPPC PC0 Case

- PC0, a recent TEPPC database, was used to populate the PLEXOS database with loads, resources and transmission capacity for zones outside of California
- Embedded in this case were several coal plant retirements
- ISO incorporated several adjustments to this case:
  - Included several additional coal plant retirements that were announced but not included in PC0
  - Excluded the resources assumed to contribute to California’s RPS portfolio that are located outside of California

Exclusion of RPS Resources from PC0

- TEPPC's PC0 case includes enough renewables to meet RPS goals in California and the rest of the WECC
  - The portfolio for California is very similar to the Trajectory Case specified for the LTPP, which includes out-of-state renewables
- To develop consistent scenarios for LTPP, the RPS builds for CA in PC0 must be adjusted according to the following framework:

	WECC-Wide RPS Resources in PC0
–	PC0 RPS Resources in CA
–	PC0 OOS RPS Resources Attributed to CA
+	CPUC RPS Portfolio (Traj/Env/Cost/Time)
=	**RPS-Compliant LTPP Scenario**

State	**Resource**	**MW**	**GWh**
New Mexico	Biomass	39	231
Idaho	Geothermal	27	198
Nevada	Geothermal	76	561
Utah	Geothermal	120	885
British Columbia	Small Hydro	90	442
Oregon	Small Hydro	13	50
Nevada	Solar Thermal	285	933
Arizona	Solar PV	319	737
Nevada	Solar PV	23	41
Alberta	Wind	1,565	4,843
Colorado	Wind	517	1,298
Montana	Wind	262	818
Oregon	Wind	871	2,373
Washington	Wind	1,252	3,004
Wyoming	Wind	86	344
Total		5,544	16,760

OOS resources to remove from PC0

Coal retirements by 2020

- PC0 includes the following coal plant retirements:
  - **AESO:** Battle Units 3 & 4 and Wabamun Unit 4 **(586 MW)**
  - **NEVP:** Reid Gardner Units 1-3 **(330 MW)**
  - **PSC:** Arapahoe Units 3 & 4 and Cameo Units 1 & 2 **(216 MW)**

- Based on conversations with Xcel and announced retirements, ISO included the following retirements:
  - Arapaho Unit 4 repowers as a natural gas combined cycle **(109 MW)**
  - Cherokee Units 1-4 retire **(722 MW)**; unit 4 repowers as a natural gas combined cycle **(351 MW)**
  - Four Corners Units 1-3 retire **(560 MW)**
  - Valmont Unit 5 retires **(178 MW)**

REFINEMENTS OF THE STATISTICAL MODEL OF OPERATIONAL REQUIREMENTS (STEP 1)

Step 1 inputs and analysis of the four scenarios results are available

- Aggregate minute and hourly profile data
- Load, wind and solar forecast error
- Monthly and daily regulation and load following requirements
- Data available at: http://www.caiso.com/23bb/23bbc01d7bd0.html

Refinements to load profiles

- Load peak demand and energy adjusted to conform to CPUC scoping memo based on 2009 CEC IEPR
- LTPP net load reduction of approximately 6,500 MW in 2020 relative to “vintage” 33% reference case due to demand side programs specified in the CPUC scoping memo
- Statewide peak load in CPUC Trajectory Case is 63,755 MW versus 70,180 MW in vintage 33% ISO Operational Study reference case

Refinements to load forecast error

- Updated load forecast error based on 2010 actual load and forecast data
- Hour ahead forecast data based on T-75 minutes in updated LTPP analysis versus T-2 hours in vintage case
- 5-minute data shows increased forecast error based on actual load data

Comparison of Load Forecast Errors

LTPP Analysis

Season	HA STD 2010 ADJUSTED For PEAK (based on 2010 data)	RT (T-7.5min) STD 10% Improve 2020 (based on 2010 data)	HA autocorr	RT Autocorr
Spring	545.18	216.05	0.61	0.86
Summer	636.03	288.03	0.7	0.92
Fall	539.69	277.38	0.65	0.9
Winter	681.86	230.96	0.54	0.85

Vintage Analysis

Season	HA STD 10% Improve 2020 (based on Vitage 2006 data)	RT (T-7.5min) STD 10% Improve 2020 (based on Vitage 2006 data)
Spring	831.11	126
Summer	1150.61	126
Fall	835.11	126
Winter	872.79	126

Refinements to wind profiles

- Wind sites were expanded to include quantity and locations consistent with CPUC scoping memo
- For new plants, wind plant production modeling based upon NREL 10 minute data production was expanded to include 21 distinct locations in California and 22 locations throughout the rest of WECC.

Refinements to wind forecasting errors

- Recalibrated wind forecast errors using profiled data

- Applied a *t-1hr* persistence method for estimating forecast errors

Comparison of Wind Forecast Errors

Region	Case	Technology	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	33%Base	Wind	9436	T-1	All	0.040	0.038	0.032	0.031
					Vintage Cases	0.050	0.045	0.044	0.041

Note: Actual wind forecast error based on existing PIRP resources is higher than forecast *t-1hr* based on profiles

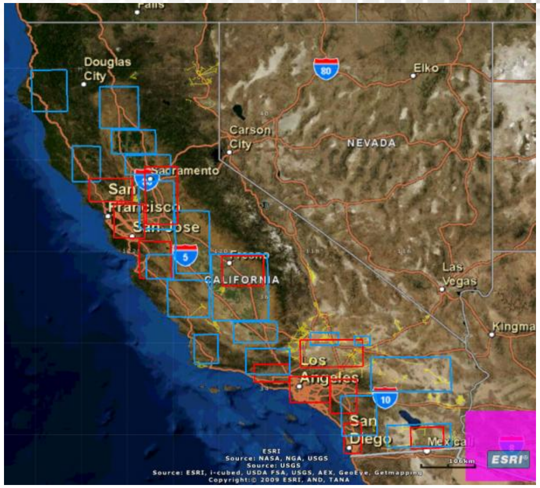
PIRP Forecast Error								
Region	Tech	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	Wind	1005	T-2	All	11.1%	10.8%	8.1%	6.0%
CA	Wind	1005	T-1	All	8.4%	7.1%	5.3%	3.9%
CA	Wind	1005	PIRP	All	10.5%	8.9%	8.4%	6.7%

Refinements to solar profiles

- Profiles for 2010 scenarios are developed based on satellite irradiation data[1] rather than rather than NREL land based measurement data used previously.
- Variability was introduced based on a plant footprint rather than a single point
- Better represents diversity of resources
- Expanded use of 1 minute irradiance data to use three locations:
  - Sacramento Municipal Utility District (SMUD) in Sacramento
  - Loyola Marymount University in Los Angeles, and
  - in Phoenix, AZ

[1] The Solar Anywhere satellite solar irradiance data can be found at:
https://www.solaranywhere.com/Public/About.aspx

Extended approach to profile small solar



- Extended method to profiling of small solar
- Define geographic boundaries of the 20 grids in Central, North, Mojave, and South area
- Choose each rectangular grid to represent an appropriate area. Each grid will have a different size rectangle
- Average the data on an hourly basis for each rectangle
- Follow similar process for developing solar profiles and adding 1-minute variability

Refinements to solar forecast errors

- Determined errors by analyzing 1-minute “clearness index” (CI) and irradiance data using *t-1hr* persistence
- To address issues that arise using the *t-1h* persistence during early and later hours of the day, use 12-16 persistence to determine solar forecast error
- Results on next slide
  – CI persistence method for Hours 12-16 similar in outcome to “improved” errors
- Recommendations:
  – Since forecast errors are based on profiles and not actual production data, recommend calibrating the simulated to the actual forecast errors when more solar data is available
  – Continue to develop forecasting error for early and later hours of the day

Comparison of solar forecast error with persistence

Comparison of Solar Forecast Errors

Region	Case	Technology	MW	Persistent	Hour	0<=CI<0.2	0.2<=CI<0.5	0.5<=CI<0.8	0.8<=CI<=1
CA	33%Base	PV	3527	T-1	Hour12-16	0.035	0.069	0.056	0.023
CA	33%Base	ST	3589	T-1	Hour12-16	0.060	0.109	0.108	0.030
CA	33%Base	DG	1045	T-1	Hour12-16	0.022	0.047	0.039	0.018
CA	33%Base	CPV	1749	T-1	Hour12-16	0.016	0.033	0.031	0.016
		All			Vintage Cases	0.05	0.1	0.075	0.05

IMPROVEMENTS TO SIMULATION EFFICIENCY

Modeling Improvements

- The model was modified to improve accuracy of modeling and efficiency of simulation while not compromising quality of results
- The major modifications implemented are:
  - Separation of spinning and non-spinning requirements
  - Generator ramp constraints for providing ancillary services and load following capacity
  - Simplified topology outside of California
  - Mixed integer optimization in California only
  - Tiered cost structure in generic resources in determining need for capacity

Separation of spinning and non-spinning requirements

- In the previous model, non-spinning includes spinning in both requirements and provision
- Spinning and non-spinning are separated in this model
  - The requirements for spinning and non-spinning are all 3% of load
  - The provision of non-spinning of a generator does not include its provision of spinning
- The separation is consistent with the ISO market definition and is needed to implement the ramp constraints as discussed below

Generator ramp constraints for providing ancillary services and load following capacity

- 60-minute constraint
  - The sum of intra-hour energy upward ramp, regulation-up, spinning, non-spinning, and load following up provisions is less than or equal to 60-minite upward ramp capability of the generator
  - The sum of intra-hour energy downward ramp, regulation-down, and load following down provisions is less than or equal to 60-minite downward ramp capability of the generator

Generator ramp constraints for providing ancillary services and load following capacity (cont.)

- 10-minute check constraint
  - The sum of upward AS and 50% of load following up provisions is less than or equal to 10-minite upward ramp capability
  - The sum of regulation-down and 50% of load following down provisions is less than or equal to 10-minite downward ramp capability

Generator ramp constraints for providing ancillary services and load following (cont.)

- 10-minute AS constraint
  - The sum of upward AS provisions is less than or equal to 10-minite upward ramp capability
  - Regulation-down provision is less than or equal to 10-minite downward ramp capability
- 20-minute constraint
  - The sum of upward AS and load following up provisions is less than or equal to 10-minite upward ramp capability
  - The sum of regulation-down and load following down provisions is less than or equal to 10-minite downward ramp capability

Simplified topology outside of California

- The topology was simplified by combining transmission areas (bubbles) outside CA according to the following rules:
  – The areas have no direct transmission connection to CA
  – The areas are combination by state or region (Pacific Northwest)
- There will be no transmission congestion within each of the combined areas

Mixed integer optimization in California only

- Model has mixed integer optimization in CA only
  - Mixed integer optimization applies to all CA generators and generators as dedicated import to CA only
  - These generators are subject to unit commitment decision in the optimization
  - Other generators outside CA are not subject to unit commitment decision
  - These generators are available for dispatch at any time (when they are not in outage)

Tiered cost structure in generic resources in determining need for capacity

- In the run to determine need for capacity, generic resources have high operation costs set up in a tired structure such that:
  - The generic resources will be used only when they are absolutely needed to avoid violation of requirements
  - The use of generic resources will be in a progressive way (fully utilizing the capacity of one generic unit before starting to use the next one)
- The model using this method can determine the need for capacity in one simulation

Tiered cost structure in generic resources in determining need for capacity (cont.)

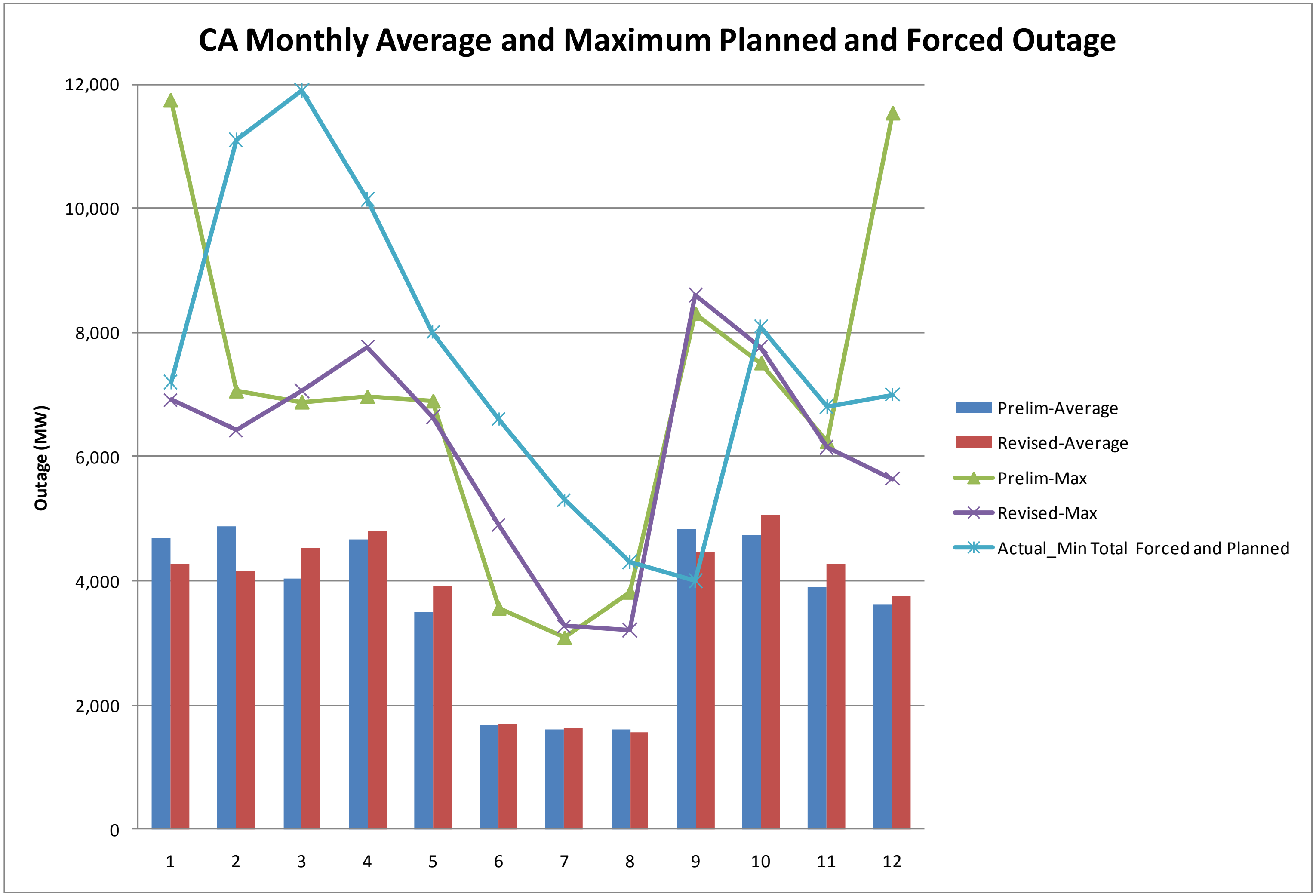
- The VOM cost and the cost to provide AS or load following of the generic resources are set up as

  Tier 1 – $10,000/MW Tier 2 - $15,000/MW

  Tier 3 – $20,000/MW Tire 4 - $25,000/MW

- In the run to determine the need for capacity startup costs of all generators are not considered for the method to work properly
- The run uses the monthly maximum regulation and load following requirements for each hour

Review of outage profile.



Note: Outage profiles need further consideration