A California Perspective on Cycling

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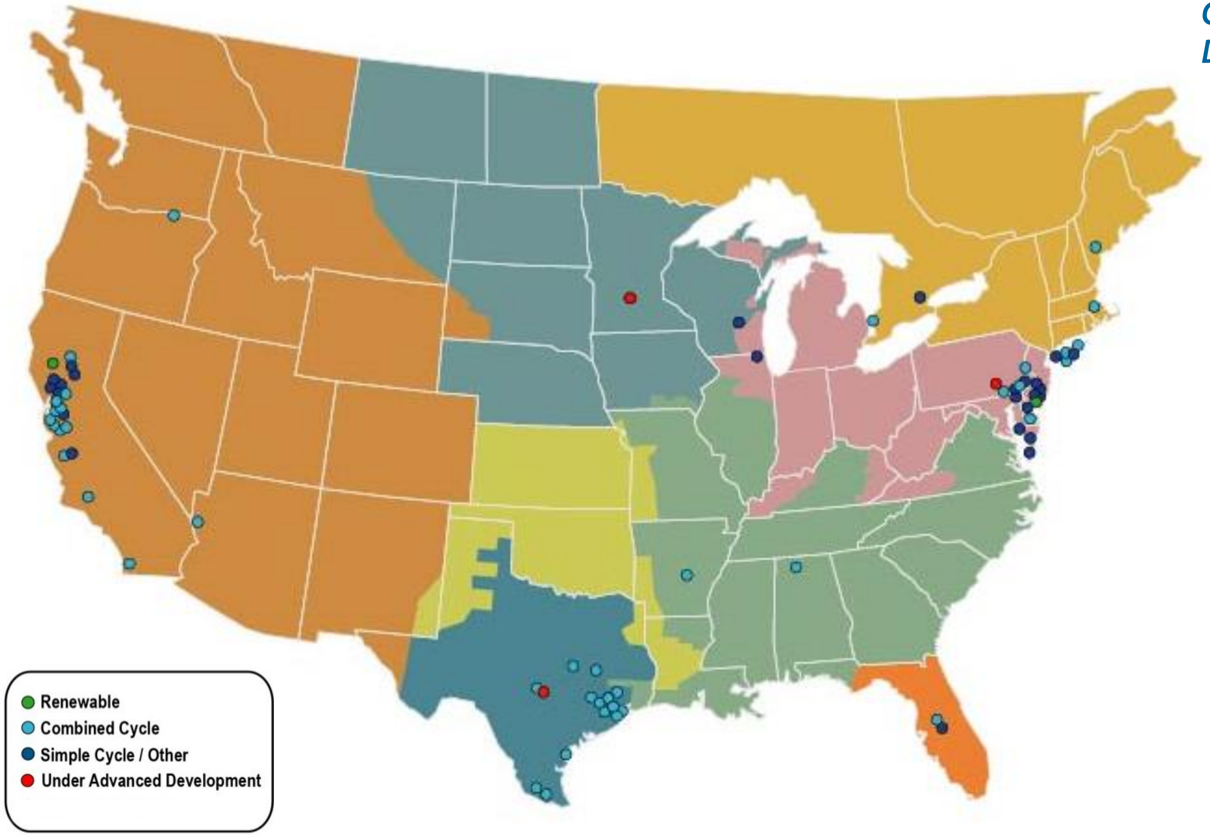
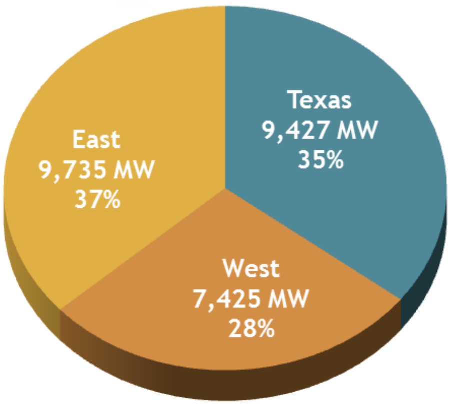
CLEAN MODERN EFFICIENT FLEXIBLE POWER GENERATION

Calpine: National Portfolio of Nearly 27,000 MW

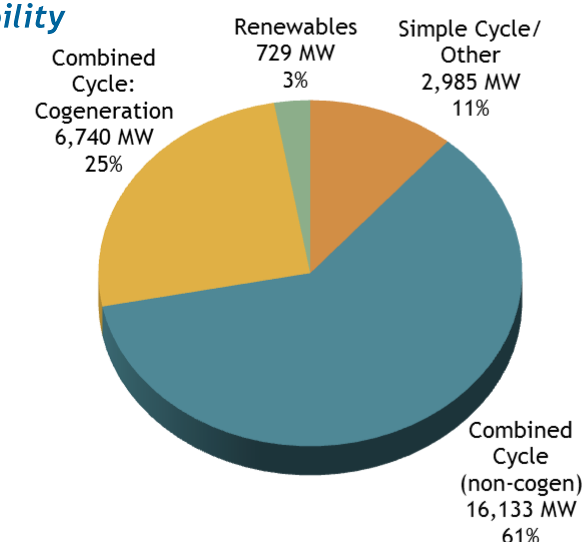


As of 7/1/2015

Geographic Diversity



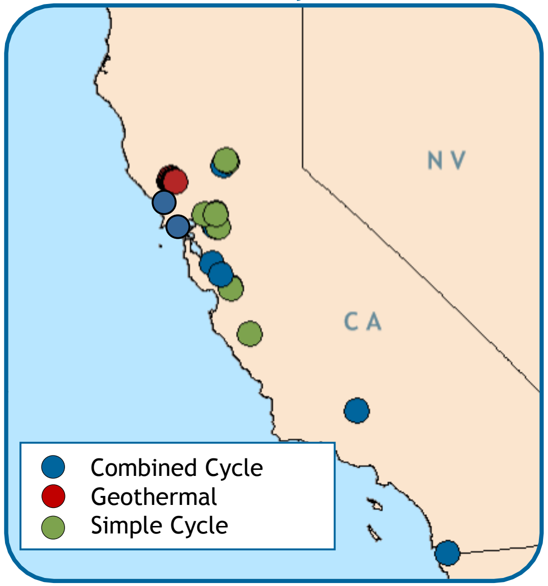
Dispatch Flexibility



- Geographically diversified portfolio: Scale in three most competitive power markets in America
- Largest operator of combined heat and power (cogeneration) technology in America
- Largest geothermal power producer in America
- Featuring one of smallest environmental footprints in America's power generation sector

Calpine has a total California footprint of ~6.4 GW

CAISO Asset Profile:



Geysers

Location: Middletown, CA

Capacity: 725 MW

Technology: Geothermal

Configuration: 15 plants

Current Generating Assets:

Efficient, flexible combined-cycle	5,070 MW
Quick-ramping (peaking) simple-cycle / Other	564 MW
Renewable baseload geothermal	725 MW
Total	***6,359 MW***

New Plants Added in 2013:

- **Russell City Energy Center**
  - 619 MW[1] Natural gas-fired combined-cycle
  - Located in Hayward, CA
  - Operating partnership with GE
- **Los Esteros Critical Energy Facility**
  - 309 MW Natural gas-fired combined-cycle
  - Located in San Jose, CA
  - Conversion of existing simple-cycle to efficient combined-cycle

Map from Energy Velocity

1: Represents total plant capacity, of which CPN is a 75% owner

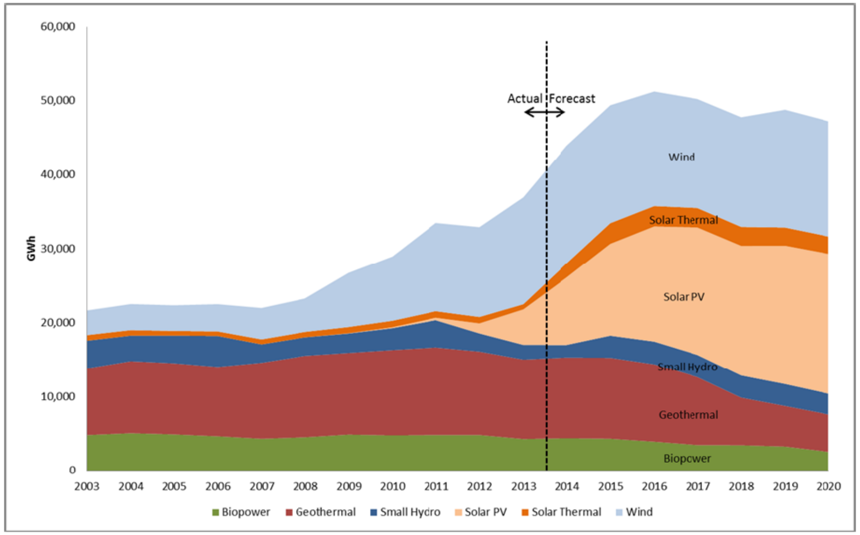
Intro

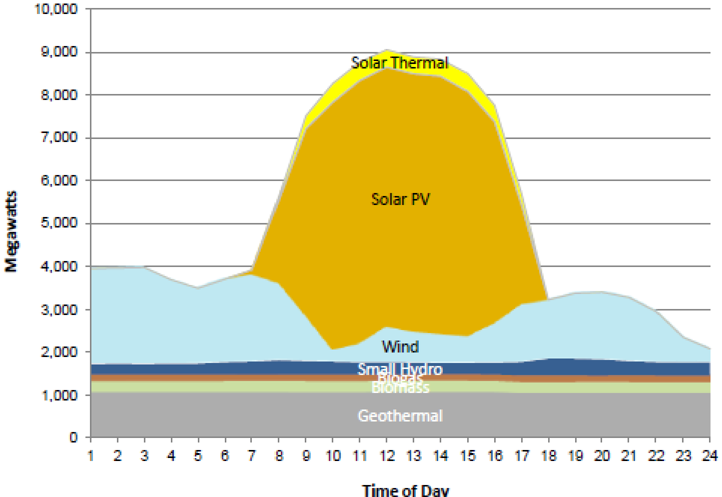
- The problem
  - Will cycling increase at high penetrations of renewables?
  - How is gas-fired generation expected to operate at higher penetrations of renewables?
  - Is the cost of cycling uncompensated?
  - Are merchant economics sufficient to support the continued operation of merchant conventional generation?

- Potential solutions
  - Energy market changes
  - Capacity market changes
    - Flexible RA
    - Generic RA

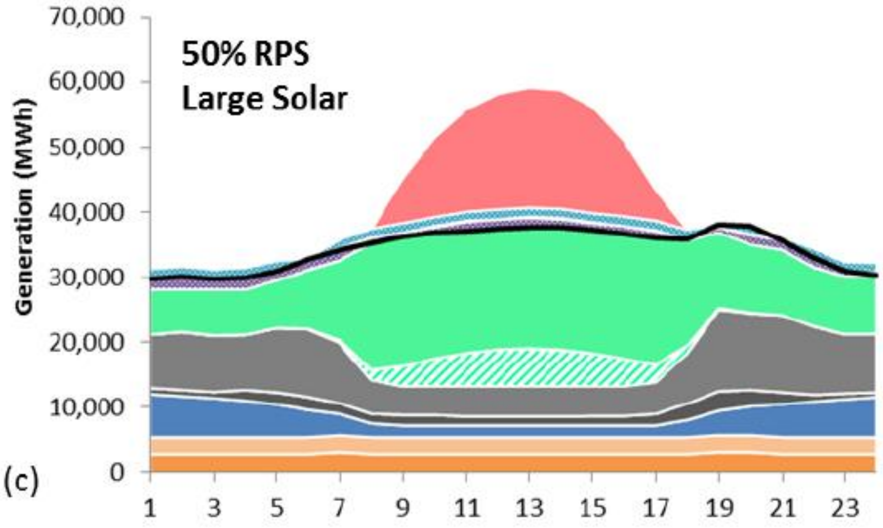
Growth in renewables

Figure 3: Renewable resource mix, actual and forecasted by year [15]





This graph shows the production of various types of renewable generation across the day.

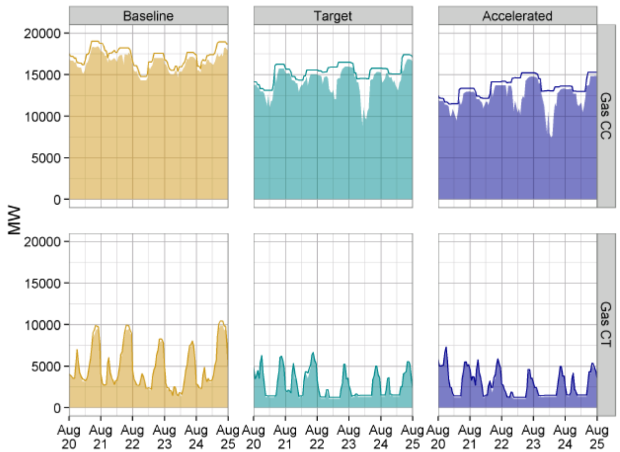


(c)

CEERT/NREL Low Carbon Grid Study—at high renewable penetrations, CCGTs run close to fully loaded when they run

Results: 4. Natural Gas/Grid Operations

Gas fleet utilization – summer typical five-day dispatch



- High utilization of committed gas fleet
- The CC fleet does not do a lot of daily cycling during the summer

- Solid line shows committed capacity of each generator type
- Shaded region shows actual dispatched energy by generator type

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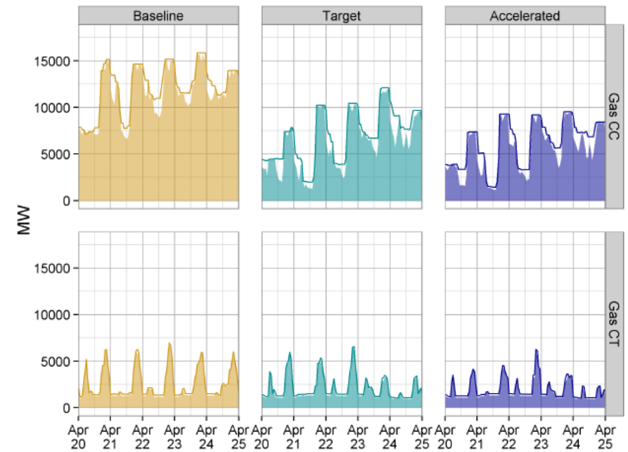
Results: 4. Natural Gas/Grid Operations

Gas fleet utilization – spring typical five-day dispatch



- High utilization of committed gas fleet
- CC fleet sees daily cycling in Target and Accelerated Cases

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Results: 4. Natural Gas/Grid Operations

California Gas Generator Operation

	Baseline	Target	Accelerated
Fleet capacity factor (%)			
CA Gas CCs	66.8	39.0	33.5
CA Gas CTs	22.2	10.8	10.4
CHP-QF	84.1	82.1	81.7
Committed fleet capacity factor (%) (Average capacity factor of each unit only counting hours when the unit is online)			
CA Gas CCs	94.9	92.0	92.0
CA Gas CTs	92.7	90.6	89.8
CHP-QF	96.0	94.1	93.7

- Committed fleet capacity factor is high for all cases, indicating that gas units are turning off, rather than turning down
  - 2013 committed capacity factor of CA CCs was ~80% and CTs was ~72% (based on EPA Continuous Emission Monitor data analysis done by the authors)

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- Hourly production cost simulations
- 33%, >50%, >66% RPS cases
- At high penetrations of renewables, CCGTs run at low capacity factors overall but high capacity factors/fully loaded once they are committed
- Storage, DR, and interchange provide operational flexibility

Cycling costs are low

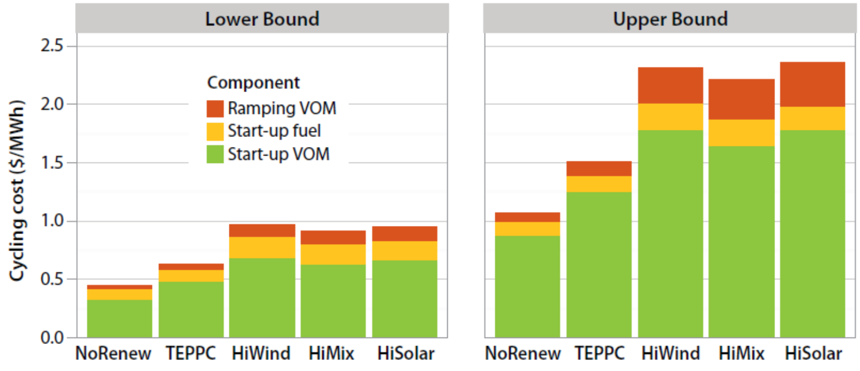


Figure ES-13. Cycling cost, showing the (left) lower- and (right) upper-bound wear-and-tear costs for each scenario

Note: These cycling costs are defined as the total system-wide cycling costs per MWh of fossil-fueled generation.

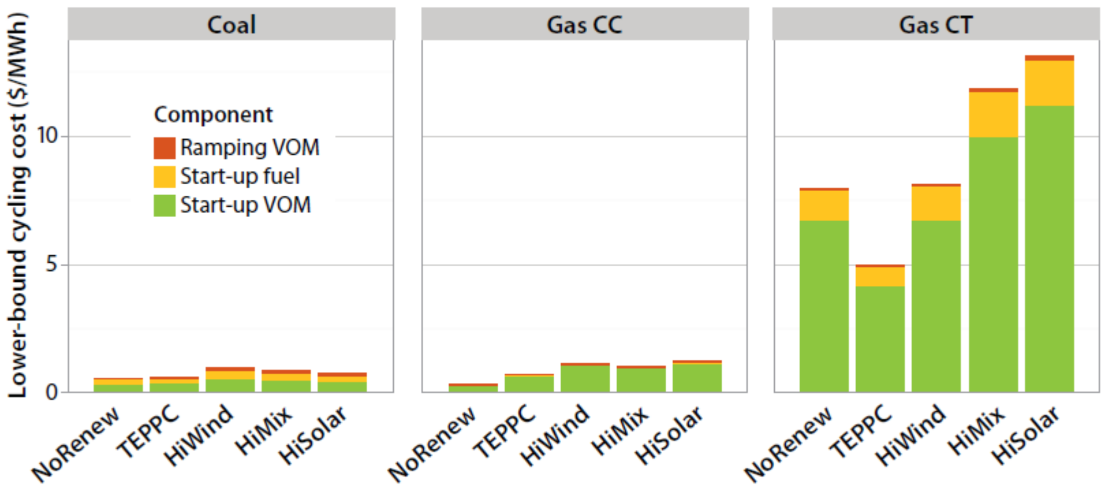


Figure ES-14. Lower-bound cycling cost for (left) coal, (center) gas CC units, and (right) gas CTs (excluding the must-run CTs)

Note: Total, system-wide, lower-bound cycling costs were disaggregated by plant type and divided by MWh of generation of that plant type.

CAISO mechanism for recovering commitment costs

- BCR
- Wear and tear can be included in commitment costs:

> In a competitive market, suppliers will submit offers at prices that reflect the marginal costs of supplying the product, *i.e.*, the incremental costs of supplying the product. Therefore, market rules in wholesale electricity markets designed to mitigate market power must allow generators to reflect all costs that are marginal to the decision to start and run generating units. Certain types of "major maintenance" costs are incurred infrequently and may appear to be fixed costs (and not marginal costs). However, the frequency is directly correlated with starting the unit and/or running the unit for a period of time after the unit has started. Therefore, the major maintenance costs are marginal costs with respect to starting or running the unit.

- Cost recovery for a specific start for a specific resource is not the issue
  - Limiting infra-marginal rents to other resources?

Inexpensive upgrades to reduce cycling costs are readily available

Upgrade	Details & Impacts
Gas Turbine Upgrades	
OEM Advanced Low Load Turndown Package	• Reduces 2x1 Min Load by approx. 85 MW
Ramp Rate Upgrade	• Increases ramp rate to 24 MW/min in 2x1 configuration • Increases spinning reserve for A/S market
Steam Turbine & HRSG Upgrades	
Thermal Blankets	• Keeps steam turbine warm offline to decrease start times
Steam Bypass	• Reconfigure system to allow faster starts • Thermally decouples gas turbine and steam turbine allowing independent control
Purge Credit	• HRSG purge on shutdown; eliminates standard purge on startup
Electric/Gas Auxiliary Boilers	• Maintains vacuum in condenser during offline hours and keeps HRSG warm

Cost Estimate:

- Suite of Flex Upgrades: **$80-120/kW** (based on total plant capacity)
  - New Build Natural Gas Generation: $1,200 -1,600/kW

Merchant CCGT economics

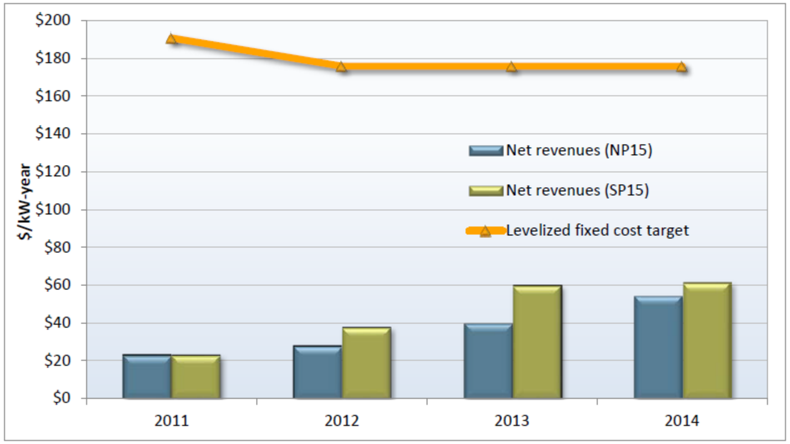
Table 1.7 Financial analysis of new combined cycle unit (2011-2014)

Components	2011		2012		2013		2014	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	53%	66%	70%	75%	84%	83%	83%	84%
DA Energy Revenue ($/kW - yr)	$101.62	$94.27	$118.95	$134.59	$286.19	$315.53	$325.36	$326.07
RT Energy Revenue ($/kW - yr)	$28.62	$30.84	$11.70	$11.62	$10.17	$10.14	$23.62	$22.08
A/S Revenue ($/kW – yr)	$1.71	$2.29	$0.37	$0.39	$0.03	$0.06	$0.08	$0.09
Operating Cost ($/kW - yr)	$108.65	$104.41	$103.01	$108.96	$256.78	$266.00	$295.03	$287.00
Net Revenue ($/kW – yr)	$23.30	$22.99	$28.02	$37.64	$39.62	$59.73	$54.02	$61.23
5-yr Average ($/kW – yr)	*$36.24*	*$45.40*						

Table 13. RA Capacity Prices by Month, 2013-2017

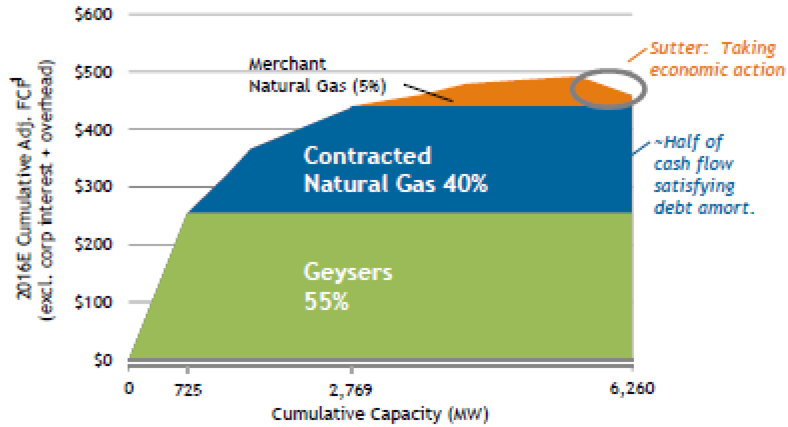
	Weighted Average Price ($/kW-month)	Minimum Price ($/kW-month)	Maximum Price ($/kW-month)	85th Percentile ($/kW-month)	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set
January	$ 1.13	$ 0.19	$ 6.43	$ 2.46	26,325.12	7.1%
February	$ 0.95	$ 0.09	$ 6.43	$ 2.25	25,675.89	6.9%
March	$ 0.92	$ 0.09	$ 6.43	$ 2.50	24,832.53	6.7%
April	$ 0.97	$ 0.09	$ 6.43	$ 2.46	25,373.88	6.8%
May	$ 1.23	$ 0.16	$ 6.43	$ 2.50	29,503.41	7.9%
June	$ 1.98	$ 0.41	$ 6.43	$ 3.00	34,701.70	9.3%
July	$ 6.81	$ 0.80	$19.77	$11.86	43,003.17	11.5%
August	$ 8.16	$ 0.97	$26.54	$15.44	47,207.26	12.7%
September	$ 4.52	$ 0.97	$11.10	$ 6.66	42,822.67	11.5%
October	$ 1.78	$ 0.25	$ 6.43	$ 2.80	29,076.93	7.8%
November	$ 1.64	$ 0.28	$ 6.43	$ 2.75	22,548.09	6.1%
December	$ 1.68	$ 0.37	$ 6.43	$ 2.75	21,552.59	5.8%

Figure 1.18 Estimated net revenue of hypothetical combined cycle unit

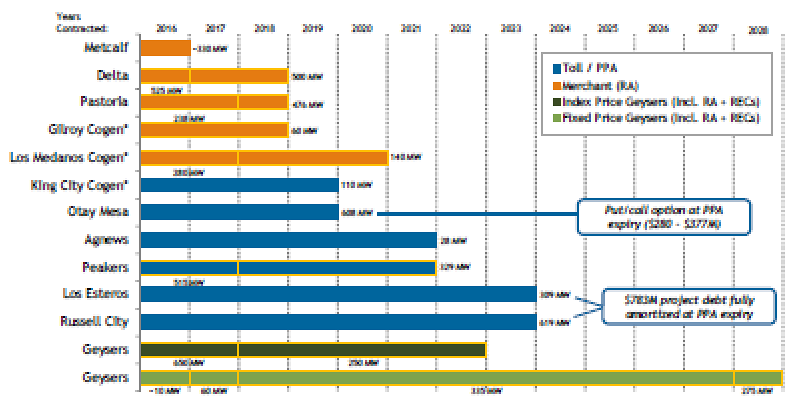


Calpine merchant and contracted economics

Today: Geysers + Contracted Gas Assets Generate ~95% of California FCF[1]…



…Providing Limited Merchant Exposure Through 2023



*Cogen plants also receive steam sales and (for Los Medanos) power sales, not included in chart.

NREL/Calpine LOLP study—load and resource balance might occur by 2024

	Low Capacity	Base	High Capacity
Hydro Available (MW)	4,730	5,951	7,428
Imports (MW)	8,300	9,500	10,100
PV Capacity Credit	N/A	Base LTPP Data	1.75x
Diablo Canyon	Retired	Included	N/A
RPS	N/A	33% OR 40%	N/A

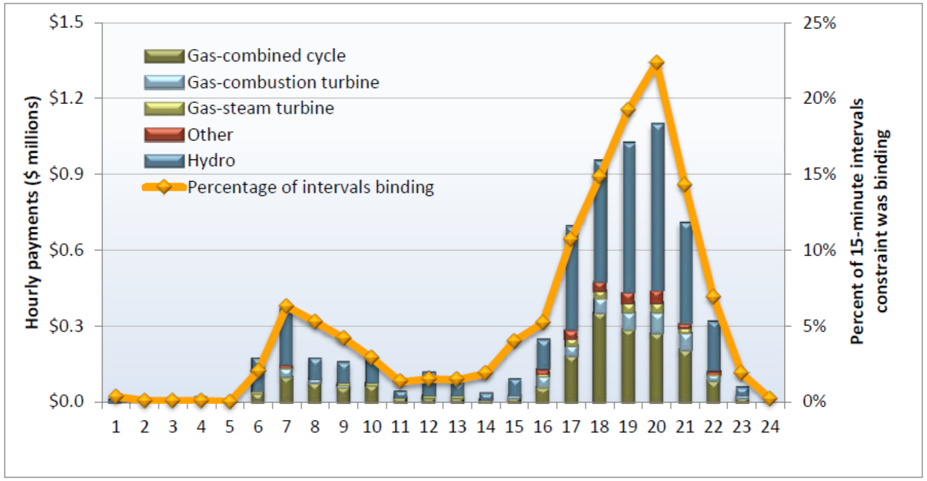
	Base LOLE (days)	Max LOLP (%)	Base LOLH (hours)	Base EUE (MWh)	Incremental capacity to meet 1-in-10
33% Base	0.03	1.54%	0.03	15.1	-770
33% Low	4.52	100.00%	10.00	11558.5	3760
33% High	0.00	0.01%	0.00	0.1	-3100
40% Base	0.01	0.61%	0.01	4.9	-1251
40% Low	4.06	100.00%	6.25	6460.2	3300
40% High	0.00	0.00%	0.00	0.0	-3590

- Traditional LOLP/reliability analysis
- Range of surplus/deficit depends on assumptions about Diablo,hydro, imports, PV profiles
- Conservative in the sense that reserve shortages were not deemed loss of load events

CAISO energy market reforms

- CME
  - Reflect commitment costs to address contingencies in LMP
  - $?
- Flexi-ramp
  - Explicitly price capacity reserved to accommodate short-term ramping in the real-time market as a reserve
    - Feedback to LMP as the result of co-optimization
    - LMP suppression by limiting scarcity/parameter pricing
    - Flexi-ramp constraint worth ~$6 million in 2014
- Are these likely to yield tens of $/kW-year in missing money?

Figure 3.12 Hourly flexible ramping constraint payments to generators (January – December)



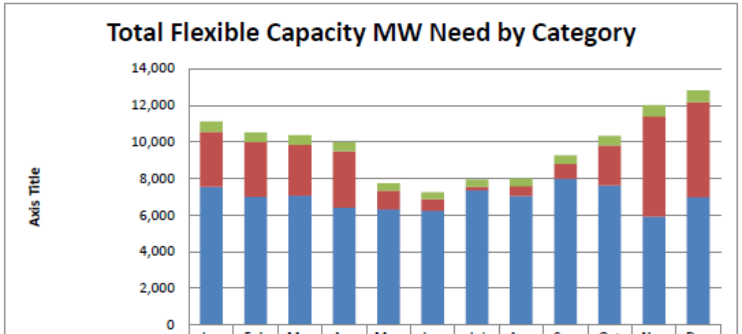
Flexible RA

- Requirement to procure capacity that is capable of ramping over three hours

- Problems with flexible RA
  - – Flexible capacity is not scarce
  - – FCRs not based on objective reliability requirement
    - No flexible RA equivalent of 1-in-10
    - Ramping is not a reliability problem—ramps can be managed by curtailing renewables
    - Poorly targeted
      - – Steam units count
        - » No consideration of the uplift costs associated with reliance on steam units to meet large ramps
        - » No consideration of forecast error, i.e., the fact that steam units cannot be used to meat ramps that are not anticipated day-ahead (or earlier)

- Potential solutions
    - Rely more on spot markets
      - – More flexible resources will have lower net GFFC
    - More granular flexible RA requirements

Figure 3: ISO System-Wide Flexible Capacity Monthly Calculation by Category for 2016



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	555	525	518	499	387	362	397	400	463	517	600	641
Peak Flexibility	3,001	2,967	2,774	3,078	1,023	629	178	560	790	2,203	5,486	5,187
Base Flexibility	7,547	7,015	7,070	6,412	6,321	6,253	7,360	7,039	8,006	7,612	5,919	6,989

Generic RA

- Renewable over-counting
  - PRM projections show over-supply through the next decade, *but*
  - Reliability analyses suggest that the system will be close to 1-in-10
  - Over-counting of renewables accounts for a large portion of the gap
    - Shift in RA counting of renewables under way (State law requires the use of ELCC but implementation has been slow)

- Managing the transition of the conventional fleet
  - ~10 GW of OTC generation expected to retire over the next ~5 years
  - Significant procurement of this OTC generation to meet generic and flexible RA requirements
    - Should modern conventional generation continue to operate with the

- Diablo Canyon retirement

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