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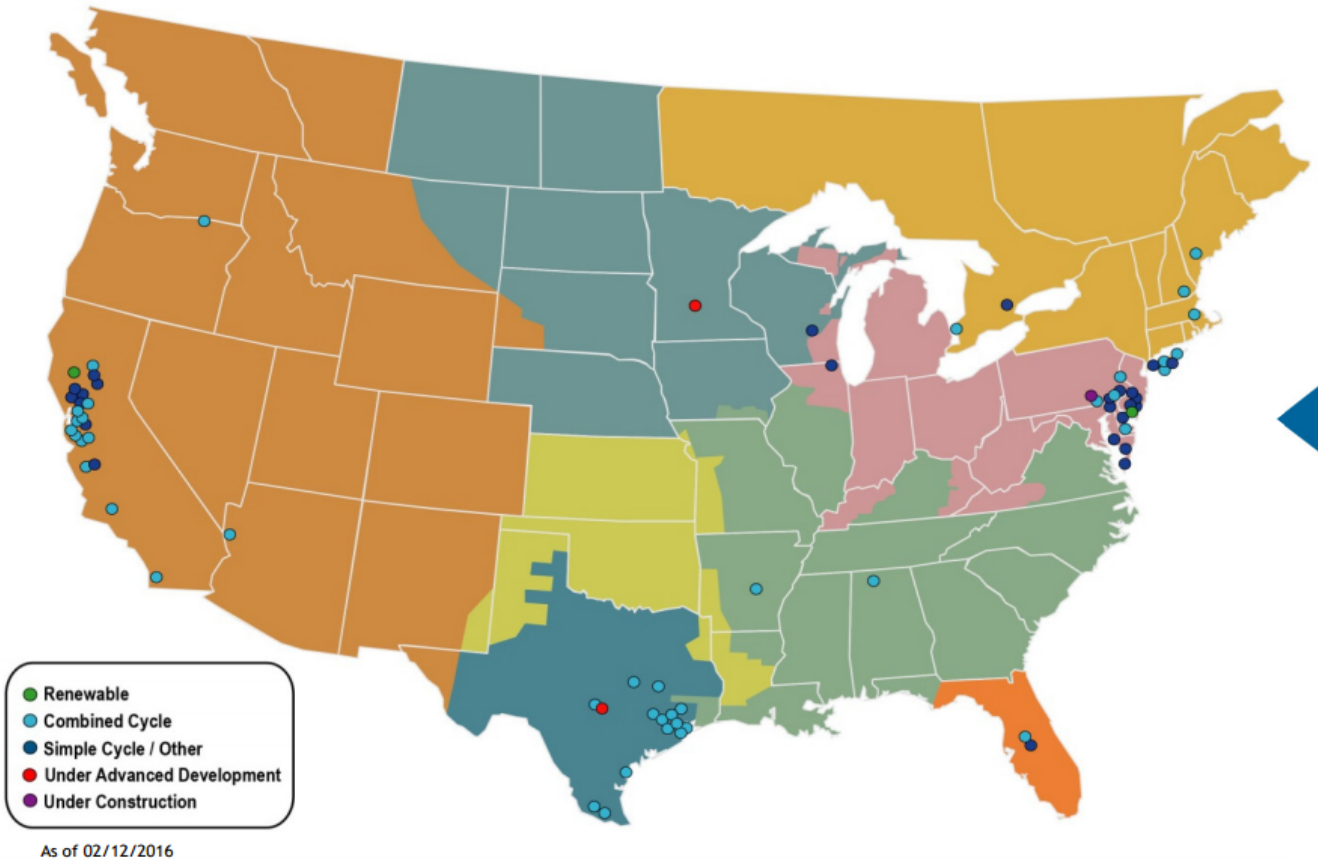
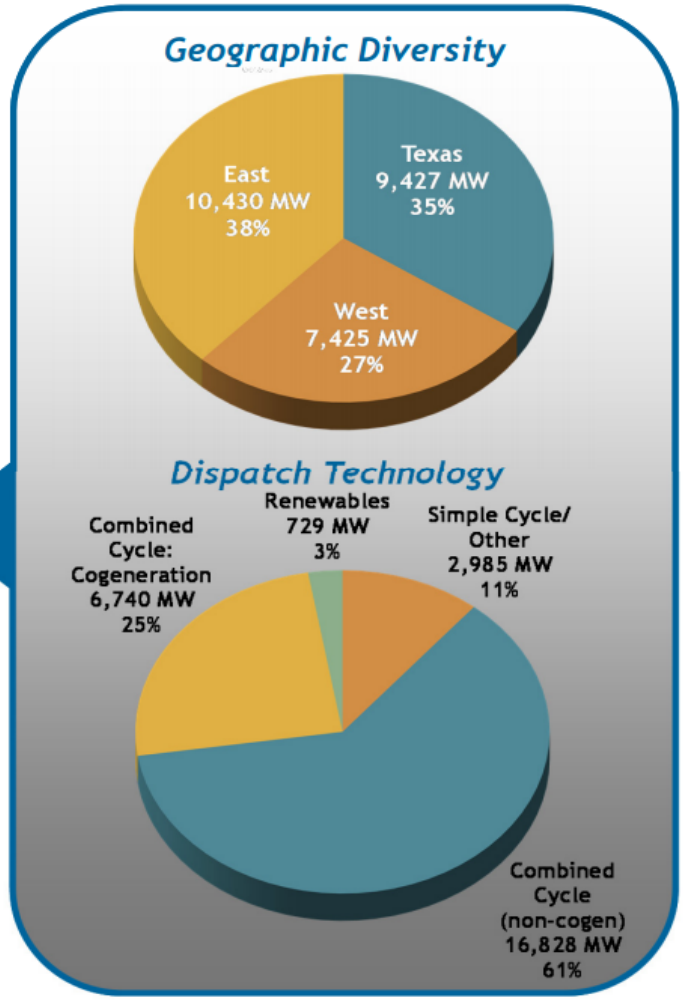
Markets in a low MC world—the case of California

September 14, 2017

CLEAN MODERN EFFICIENT FLEXIBLE POWER GENERATION

National Portfolio of Approximately 27,000 MW





- 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

Intro

- California has been tough for merchants
- Renewables impact the market, but
- Poor merchant market at least as much attributable to poor market design and regulatory interventions as renewables
- Policy-induced oversupply ensures that spot markets never send an investment signal
    - No market-based investment
    - Existing resources struggle to cover costs
- Notwithstanding the fact that California is not a “real” market, it provides useful insight into market design issues associated with higher penetrations of renewables

California OOM procurement—all new resources get long-term contracts, existing merchant resources relegated to spot market ghetto

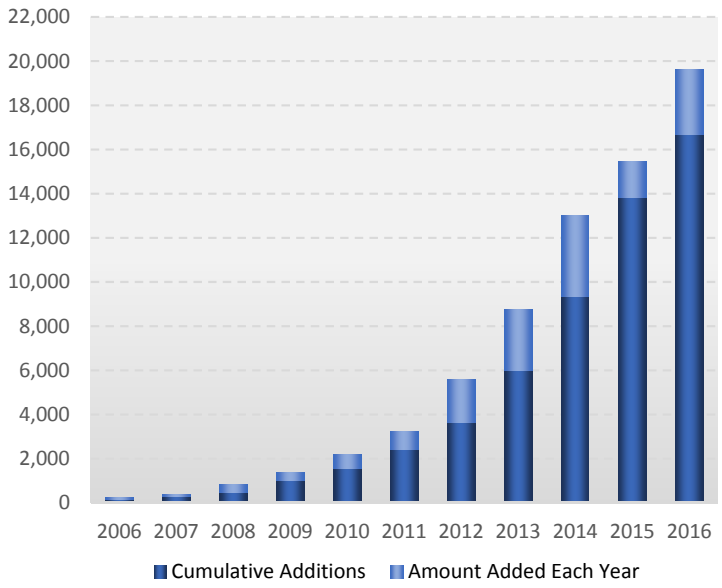
California Central Planning Has Guaranteed Excess Capacity

- CPUC determines need for new resources with a 10-year forward look
- Makes assumption that existing resources will continue to operate if they are covering "Going Forward Costs"
- As capacity deficiencies emerge, CPUC authorizes long term contracting of new resources by IOUs through discriminatory RFPs

Conventional generation under LTPP
10,000 MW

California RPS Laws Increasingly Aggressive	
2002	20% by 2017
2011	33% by 2020
2015	50% by 2030
Current Leg. Proposal	100% by 2045

Renewables additions ~**20,000 MW**



Generous Net Energy Metering (NEM) Rules Have Led To Significant Penetration

At least 5,000 MW

State policies and interventions in FERC's wholesale electricity market, deprive merchant generators of a viable opportunity to recover their investments.

Source: Graph: CPUC RPS Procurement Status Report Q4 2016, Conventional Gen from CEC Power Plant Data.

Energy and capacity market compensation has been low

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Table 1.8 Financial analysis of new combined cycle unit (2012-2015)

Components	2012		2013		2014		2015	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	70%	75%	84%	83%	83%	84%	92%	93%
DA Energy Revenue ($/kW - yr	$118.95	$134.59	$286.19	$315.53	$325.36	$326.07	$251.35	$251.61
RT Energy Revenue ($/kW - yr)	$11.70	$11.62	$10.17	$10.14	$23.62	$22.08	$12.39	$9.45
A/S Revenue ($/kW – yr)	$0.37	$0.39	$0.03	$0.06	$0.08	$0.09	$0.04	$0.06
Operating Cost ($/kW - yr)	$103.01	$108.96	$256.78	$266.00	$295.03	$287.00	$224.16	$215.35
Net Revenue ($/kW – yr)	$28.02	$37.64	$39.62	$59.73	$54.02	$61.23	$39.62	$45.77
4-yr Average ($/kW – yr)	*$40.32*	*$51.09*						

Table 1.6 Financial analysis of new combined cycle unit (2016)

Zone	Scenario	Capacity factor	Total energy revenues ($/kW-yr)	Operating costs ($/kW-yr)	Net revenue ($/kW-yr)
NP15	Day-ahead prices and default energy bids	21%	$75.88	$64.65	$11.23
	Day-ahead prices and default energy bids without adder	23%	$83.12	$70.45	$12.67
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	22%	$79.73	$66.82	$12.91
SP15	Day-ahead prices and default energy bids	29%	$104.92	$84.40	$20.52
	Day-ahead prices and default energy bids without adder	32%	$111.20	$88.83	$22.37
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	30%	$108.51	$86.38	$22.13

Table 6. Capacity Prices by Compliance Year, 2016-2017

	2016 Capacity	2017 Capacity
Contracted Capacity (MW)	90,341	68,377
Percentage of total contracted MW in dataset	30%	22%
Weighted Average Price ($/kW-month)	$2.90	$2.96
Average Price ($/kW-month)	$2.53	$2.57
Minimum Price ($/kW-month)	$0.27	$0.15
Maximum Price ($/kW-month)	$26.54	$6.43

Potential market design/condition changes associated with higher penetrations of renewables

- Capacity compensation may become more important relative to energy/AS compensation. Consequently, important to
  - Enforce locational requirements
  - Measure and reward capacity accurately, especially capacity associated with renewables
  - Flexible forward capacity products?

- Intermittent renewables may cause or require changes to other markets
  - More variable energy prices reward flexible resources
  - Additional reserves/AS?

Enforce locational requirements in capacity markets

- Out-of-market entry has generally assured surpluses and low prices
- Some specific areas are not oversupplied, but not all locational requirements are enforced in the bilateral RA market, so prices never rise to support the continued operation of resources that are critical to local reliability
- As the economic viability of resources that are critical to local reliability has been threatened, increased reliance on non-market mechanisms
- Calpine is in the process of negotiating RMR contracts for three different plants
  - Cost-of-service compensation
  - Costs socialized to all load

Solar capacity counting

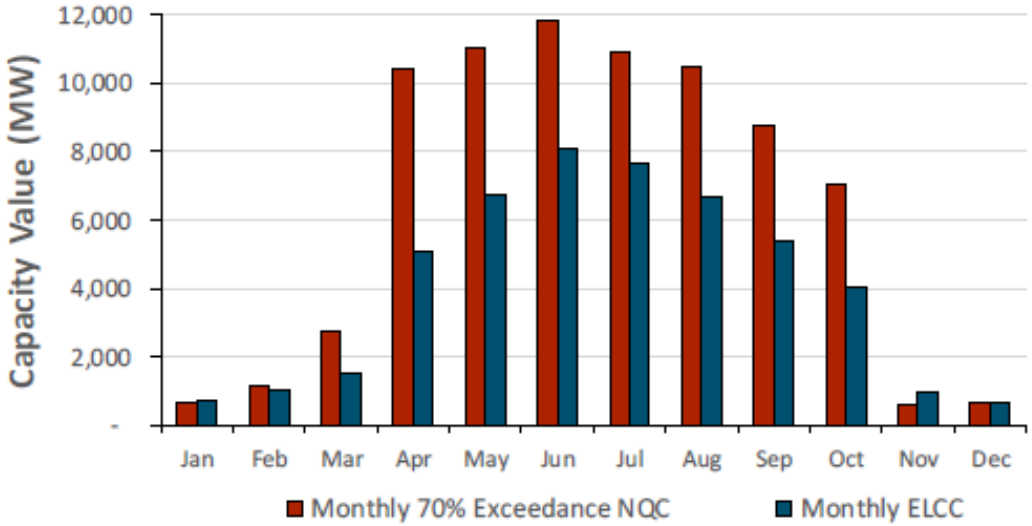


Table 6: Marginal ELCC Values by Region and Technology

	Northern Cal	Southern Cal	Northwest	Southwest
33% RPS Case Marginal ELCC Values				
Wind	21%	14%	40%	24%
Tracking PV	21%	15%		12%
Fixed Axis PV	13%	10%		8%
Distributed PV	12%	8%		
43.3% RPS Case Marginal ELCC Values				
Wind	27%	22%	43%	20%
Tracking PV	8%	4%		3%
Fixed Axis PV	4%	4%		1%
Distributed PV	5%	2%		

Flexible capacity

- California introduced a flexible capacity product to address large ramps associated with solar
  - Need based on largest 3-hour system net load ramp
  - Resources count to the extent that they are able to ramp over three hours

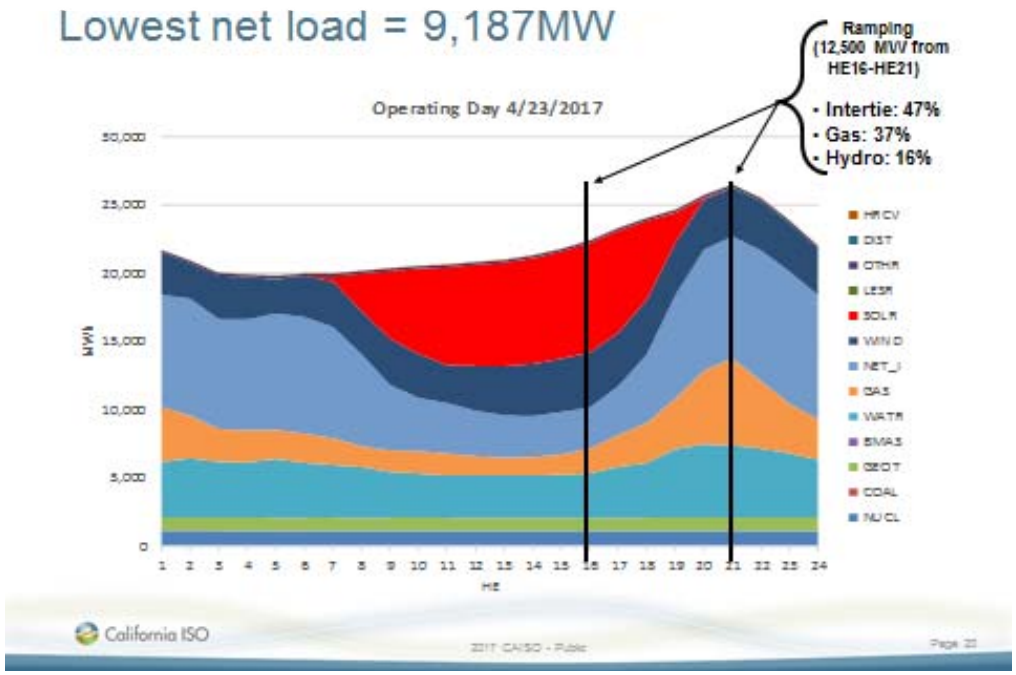
- Product is not working
  - 30 GW of supply chasing ~10 GW of demand, so no premium and hasn't really changed what capacity resources are procured
  - No connection between forward capacity procurement and actual operations
    - Flexible capacity resources are not actually used to meet ramps
    - Flexible capacity resources are not necessarily available to meet ramps

Flexible capacity product poorly targeted

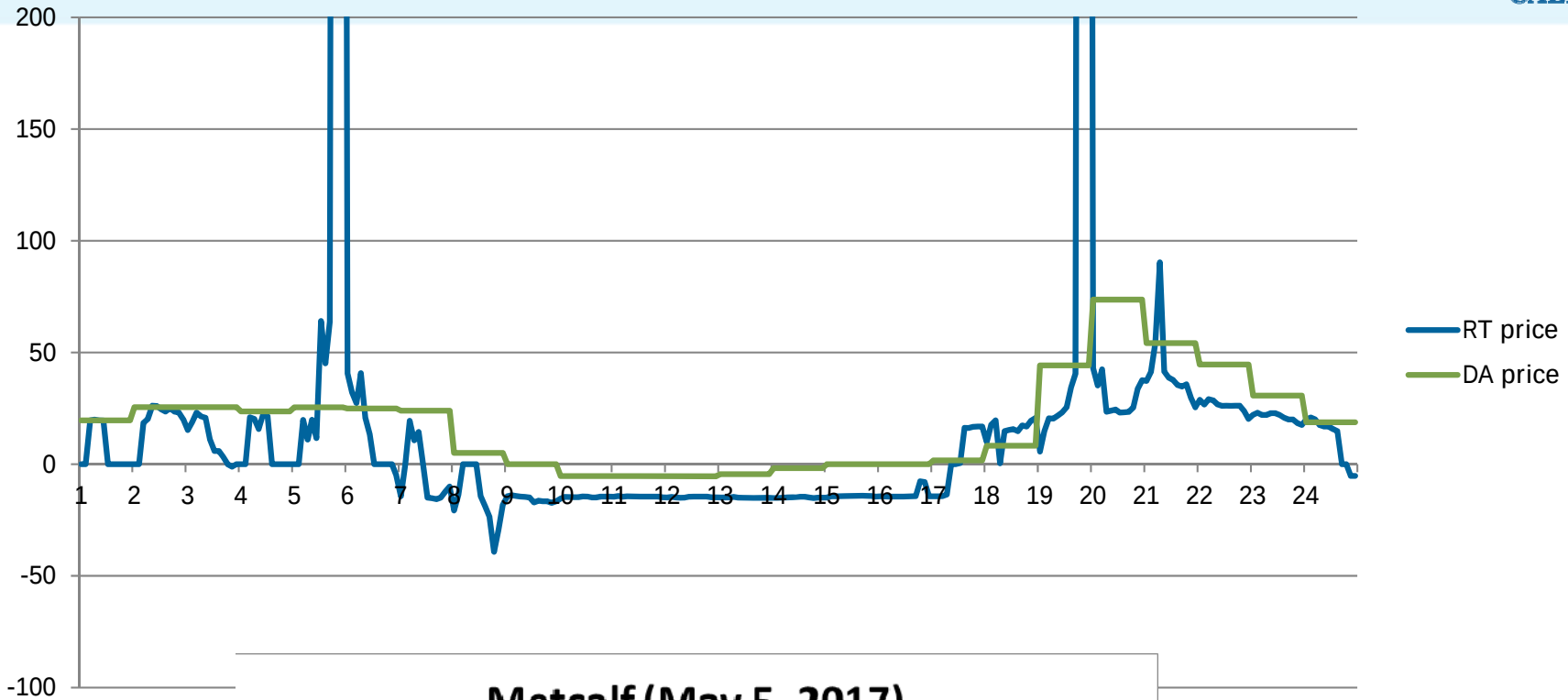
Table 10.4 Average flexible resource adequacy capacity and availability

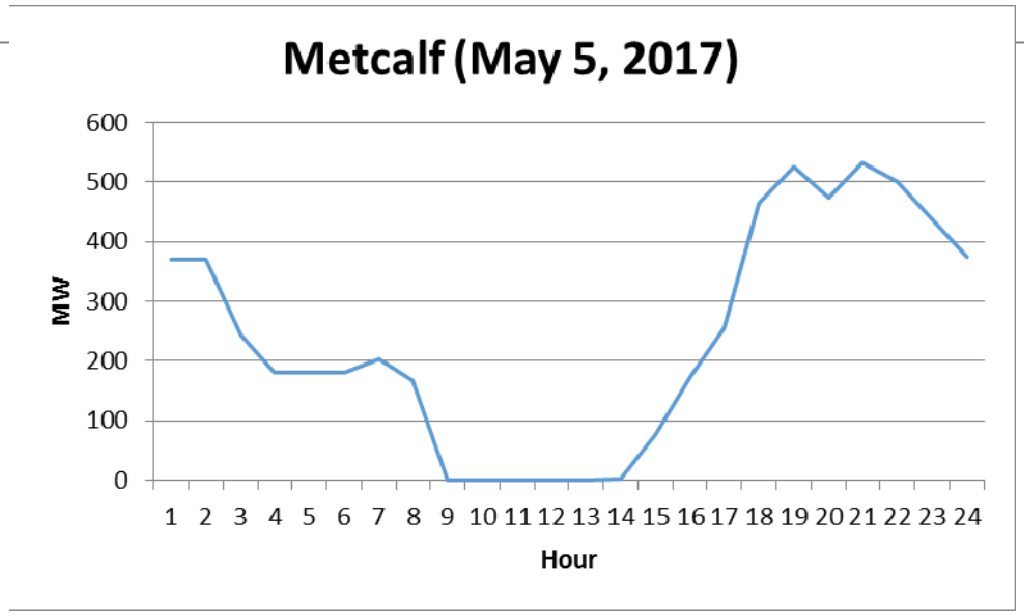
Month	Average DA flexible capacity (MW)	Average DA Availability		Average RT flexible capacity (MW)	Average RT Availability	
		MW	% of RA Capacity		MW	% of RA Capacity
January	10,565	9,402	89%	6,154	5,524	90%
February	10,750	8,549	80%	5,755	4,905	85%
March	10,360	8,982	87%	5,929	5,013	85%
April	9,489	7,717	81%	4,846	4,315	89%
May	7,961	6,672	84%	3,598	3,218	89%
June	8,876	8,091	91%	5,398	4,979	92%
July	8,486	8,006	94%	5,593	5,146	92%
August	8,315	7,726	93%	5,423	4,858	90%
September	8,655	8,009	93%	5,681	5,163	91%
October	9,751	8,616	88%	6,505	5,438	84%
November	11,139	9,834	88%	6,114	5,373	88%
December	11,645	10,588	91%	7,114	6,251	88%

Lowest net load = 9,187MW

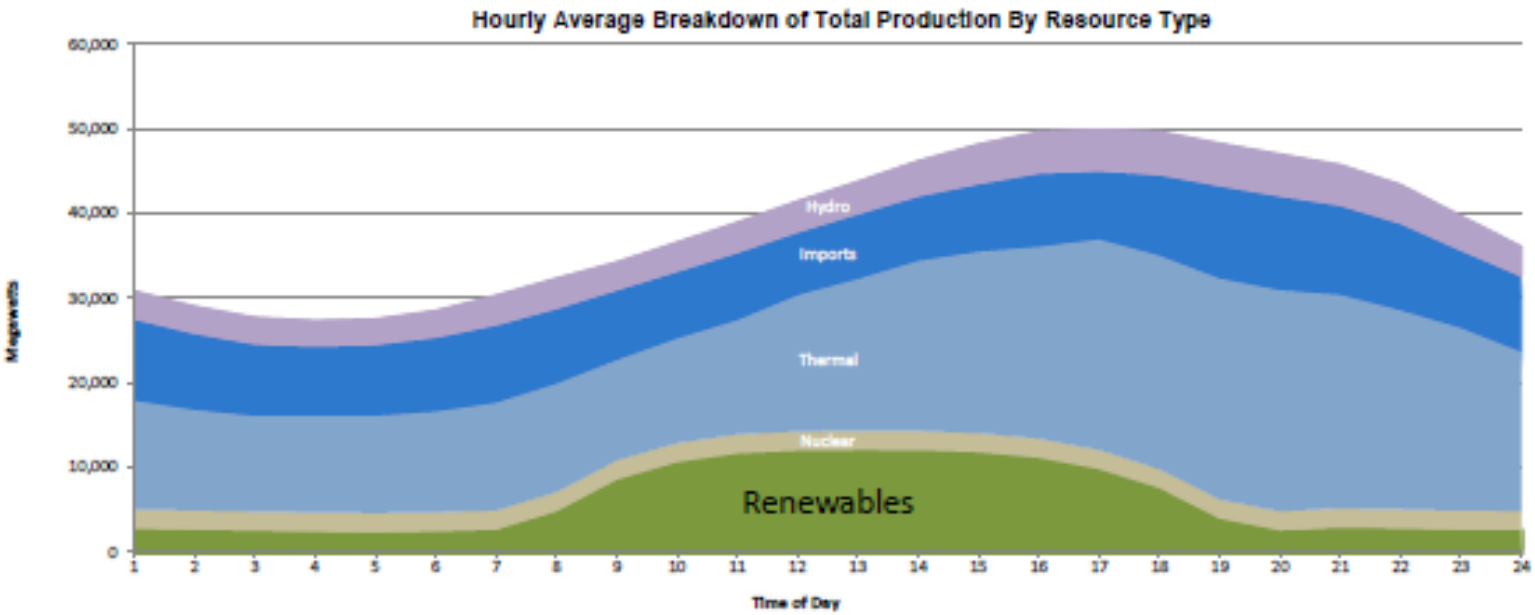


Volatile energy prices change operations/reward flexibility

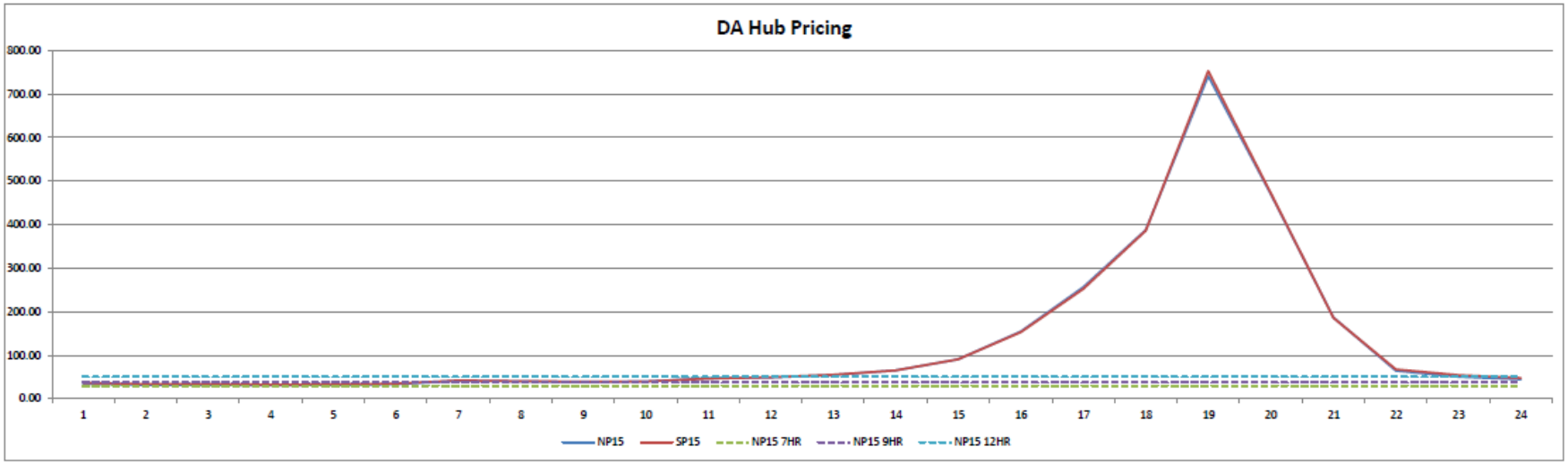




It still gets hot and the sun doesn't always shine



This graph depicts the production of various generating resources across the day.



Additional AS/reserve products?

- Trouble with ramps in actual operations.
- Insufficient or insufficiently fast capacity or insufficient capacity committed?
- More resources could be committed by specifying additional reserves
- Tradeoff between renewable curtailments associated with additional unit commitments and reliability?
- Flexible capacity product more narrowly focused on very fast resources with low minimum loads?