How to Manage Future Grid Dynamics:

Quantifying Smart Power Generation Benefits

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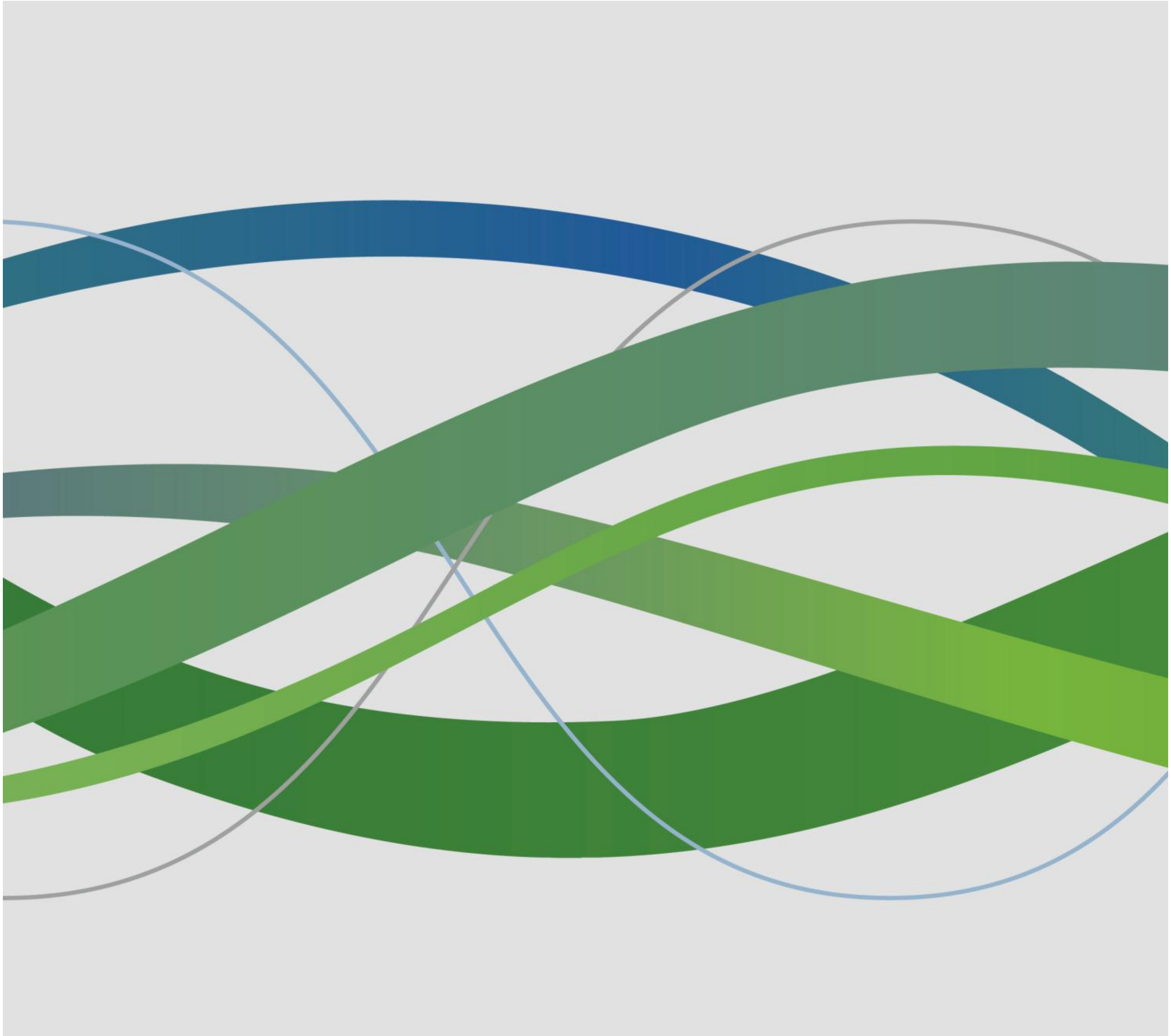

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1. Introduction and Purpose

Electricity grids face a variety of trends which impact current and future markets and operations. Increased penetration of variable renewable energy production creates the need for more ancillary services to smooth fluctuations in renewable output and to provide for forecast errors in those outputs. Thermal plant retirements and environmental restrictions impact resource adequacy. Resources such as Demand Response, distributed resources and new storage and communication technologies create uncertainties in how these important new resources interact with one another. Lastly, new resources can create changing power flows and import/export transfers between balancing authority which creates uncertainties with network and/or grid expansion.

To investigate these future uncertainties we simulate market conditions to investigate impacts and plan for future events. In this paper, we have created future scenarios to explore different resource portfolios meet these key uncertainties cheaply and reliably. A key technology that we explore is Smart Power Generation.

We define Smart Power Generation (SPG) as resource capacity having high operational flexibility, high energy efficiency, and diverse fuel capability. Operational flexibility requires generation to have multiple dynamic operation modes, from ultra-fast grid reserve to efficient base load generation. SPG has fast start-up, shut-down, and load ramps with agile dispatch and is able to supply MWs to the electricity grid within 1 minute and full power in 5-10 minutes. Ideally, SPG should be suitable for base load generation, peaking, and balancing requirements and have independent operation of multiple units with remote operation for off-site control. SPG should be capable of being situated within or near load pockets and have low maintenance costs regardless of operation method including some sort of grid black-start capability. SPG should be energy efficient with sustainable and affordable power systems requiring the highest level of simple-cycle energy efficiency available. Characteristics of SPG include high efficiency in a wide load range, from almost zero load to full load, low water consumption, and low CO2 emissions regardless of operation method, expandable plant size for future plant size optimization and high reliability and availability through multiple parallel units.

Modern, state of the art combustion engines designed for utility scale-operations (plant sizes 50 to over 500 MW), exhibit many features of the Smart Power Generation concept. They have the highest simple cycle efficiency, lowest CO2 emissions and fastest ramp rates commercially available for thermal assets; have minimal to no water consumption; deliver power to the grid within 1 minute and full output in 5 – 10 minutes; have no equivalent operating hour penalties for starts, stops or cycling; and can operate at very low plant loads while maintaining high efficiencies. While all thermal technologies share some features of the Smart Power Generation concept, modern combustion engines are considered here as an alternative to the more traditional combustion turbine. Therefore, we use Wärtsilä engines as a proxy for Smart Power Generation. Wärtsilä engines were chosen as representative of state of the art combustion engine prime movers. The Wärtsilä 20V34SG (SPG simple cycle) is a state of the art combustion engine with a per-unit output of 10 MW. It is commonly configured with engines in parallel for plant sizes of several hundred MW. The efficiency of this unit is greater than commercially available gas turbines but less than a combined cycle combustion turbine. Start times are 5 minutes, with no minimum up or down times, and no start cost penalties. Ramp rates are 6 MW/minute per unit, or 60 MW per minute per 100 MW block. Capital costs are equivalent to those of aeroderivative gas turbines but approximately 30% less than Gas Turbine Combine Cycles (GTCCs). Smart Power Generation capacity such as Wärtsilä 20V34SG units reject heat to a radiator field and have no water consumption for process needs. For the remainder of this document, we will investigate the impacts of SPG simple cycle using the Wärtsilä 20V34SG operating parameters unless otherwise noted.

In addition to the SPG simple cycle configuration, we also investigate resource portfolios using Smart Power Generation combined cycle configurations. Wärtsilä 18V34SG units (Flexicycle™ solution) combine the advantages of a flexible simple cycle plant with the superb efficiency of a combined cycle plant, in a unique way. The Flexicycle™ power plants can be optimized for different outputs in the 100 to 500 MW range. The power plant solution is based on gas fired combustion engines and steam turbine combined cycle. Each engine is equipped with waste heat recovery steam generator. The power plant has one common steam turbine with condenser. The power plant cooling is typically arranged so that the combustion engines are cooled with closed loop radiators and the steam cycle with cooling towers. For the remainder of this document, we will investigate the impacts of SPG combined cycle using the Wärtsilä Flexicycle™ power plants operating parameters unless otherwise noted.

In Section 2, we discuss our simulation assumptions specific to California; in Section 3 we discuss day ahead hourly simulation results. In Section 4 we simulate 5 minute real time dispatch and in Section 5 we examine long term planning Resource Adequacy impacts.

2. CAISO Issues and 2020 Simulation Assumptions

While there may be important differences in how North American Regional Transmission Organizations manage markets and resources, they share many similarities including the desire to reduce the cost of providing energy and ancillary services to their members. Ancillary services are those non-transmission services that support delivery of energy from source to sink[1].

We focus on the California ISO (CAISO) as a study system because it has well developed markets; a clearly defined renewable energy target for the year 2020; has been active in adopting Demand Response, new supply technologies and incorporating distributed energy resources into wholesale operations. In addition, CAISO and the California Public Utility Commission (CPUC) have provided publicly available electric grid data which support dispatch from a wider Western Electric Coordinating Council (WECC) region through a variety of different production costing software. The data and tools provide the basis for simulations and analysis in this white paper. The CPUC and CAISO host a public forum for long term planning, providing future scenario descriptions and data that are publicly available and can be used to estimate impacts. These future scenarios typically involve varying load patterns, renewable penetration, demand response and the addition of new thermal generation (typically gas turbines in simple or combined cycle).

2.1 Current Market and Operational Issues facing CAISO

The main trends and issues faced by CAISO[2] include the following:

Renewable Portfolio Standards: The most recent drivers of infrastructure changes on the California grid are primarily environmental policies. California's Renewable Portfolio Standard (RPS) program aims to alter the in-state generation and import mix by requiring jurisdictional utilities to obtain a progressively larger proportion of their electricity delivered to end users from renewable energy. Legislation mandates the renewable energy generation mix rising from approximately 14% in 2010 to 33% by 2020[3]. In addition, California has implemented a law that requires reductions in greenhouse gas emissions to 1990 levels by 2020. A combination of renewable energy and energy efficiency is expected to fulfill most of those emissions reductions for the power sector, at least until 2020. With the exception of geothermal and biomass, most other eligible renewable resources have variable production and also have relatively low capacity factors as compared with fossil-fuel plants. Variability in renewable resources gives rise to increased ancillary service requirements[4] and interconnection standards debated in CAISO Rule 21

[1] Ancillary Services and System Flexibility requirements are discussed in Section 2.3.

[2] 2011 Annual Report on Market Issues and Performance

[3] SB 1078 (2002), SB 107 (2006), and SB 2 (2011).

[4] www.nerc.com.

discussions[5]. Larger interconnected renewable resources that directly bid on wholesale markets would probably require direct telemetry under proposed Rule 21 amendments as well as changes to voltage protection schema currently being discussed. Smart Power Generation can be used to balance fluctuations in renewable generation created by miss-forecasted schedules.

Distributed Energy Resource (DER) Target: Targeting 12,000 MW of distributed[6] generation resources in California by 2020, CAISO load following requirements could triple[7] over 2011 procurement to account for forecast error. Regulation requirements could also double by 2020 to allow for greater need for instantaneous balancing. Aware of these issues, CAISO has begun efforts to increase visibility of DER resources leading to more efficient procurement of regulating and load following requirements. CAISO is planning more efficient database of planned and existing DER projects and grid response programs, more efficient loading of DER and existing grid components, and more efficient voltage management[8] programs to reduce the need for regulation and load following.

Long Term Resource Adequacy: The California State Water Resources Control Board has called for the retirement or modification of 16 power plants by 2020 within the CAISO balancing authority that are critical for system and local reliability and to ensure sufficient availability of ancillary services to support renewable resource integration[9]. In the State's Long Term Procurement Planning process which ensures reliable operation[10], new or Once Through Cooling (OTC) re-powered generation capacity is planned but not certain to replace the impacted generation. In addition, non-renewable generation capacity has not grown significantly in the last few years, while renewable generation increases to meet the state's renewable requirements. As more renewable generation comes online, CAISO has highlighted the need to backup and balance renewable generation with the flexibility of conventional generation resources to maintain reliability.

New Market Rules to incent flexible generation and promote faster ramping responses. CAISO has proposed spot market (five minute interval) and forward procurement (integrated day-ahead) products that will provide additional generation dispatch flexibility to improve reliability as more variable energy resources are integrated. CAISO has also proposed incorporating specific requirements for flexible unit

[5] www.cpuc.ca.gov/energy/procurement/LTPP/rule 21.htm.

[6] Distributed resources are utility, residential, commercial and industrial Photovoltaics (PV), Central Heat and Power (CHP), Self Optimizing Customer bundles of technology (SOC), Plug in Electric Vehicles (PEV), utility, residential, industrial and commercial Distributed Energy Storage and Demand Response Programs.

[7] Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources, June 2012.

[8] Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources, June 2012.

[9] The affected units will require a "Once-Through-Cooling" process to meet state standards and are often referred to as "OTC re-powered" units. Capacity estimate vary but 12 GW is the usually sited estimate impacted by OTC standards. http://www.caiso.com/208b/208b8ac831b00.pdf.

[10] According to NERC, Balancing Authorities should operate in normal operating conditions, protect for all single contingencies (N-1), protect against (N-2) double line outages, and after a single contingency be able to re-adjust the system to support the loss of the next most stringent contingency. See NERC Operating Guidelines, www.NERC.com.

operating characteristics in the state's year-ahead resource adequacy requirements and may eventually develop into a five year forward capacity procurement process. Currently the load pays for the incremental costs for additional reserves and ancillary services, and there is debate surrounding whether the resources causing those incremental reserves be responsible for the costs.

Heavy Use of Demand Response to meet load obligations invites uncertainty of response. Total demand response programs in 2011 were estimated to be 2,270 MW. The most demand response dispatched during any hour in 2011 was only about 350 MW during August and September; the bulk of the dispatch was under price responsive programs. By 2020, Demand Response programs could be well over 10,000 MW[11] and are subject to uncertainties in actual response, how quickly the resources respond to requests or to price signals and early downturn of resources before the required response interval.

Limited Availability of Natural Gas Units reduces effectiveness to manage real time and peak requirements: In 2011, almost 3,000 MW of use-limited gas resources are used to meet resource adequacy requirements. Most of these resources are peaking units within more populated and transmission constrained areas that are only allowed to operate 360 hours per year under current California air permitting regulations. Market participants submit to the ISO use plans for these resources, but are not actually required to make them available during peak hours. In 2011, only about 81 percent of this capacity was available in the day-ahead market during the highest 210 load hours. In real-time, only about 1,000 MW of this 3,000 MW of capacity was scheduled or bid into the real-time market.

Limited import availability to meet obligation: In 2011, almost 4,000 MW of imports are used to meet resource adequacy requirements in California. About 93 percent of this capacity was scheduled or bid in the day-ahead market during the 210 highest load hours. The high dependence of imports to meet critical peak requirements places stress on the transmission system.

2.2 2020 Simulations

CAISO and the California Public Utility Commission (CPUC) have provided publicly available electric grid data which support dispatch from a wider Western Electric region through a variety of different production costing software. For our simulations, we use PLEXOS, production costing software licensed by Energy Exemplar. As part of California's Long Term Procurement Planning (LTPP) process, the CPUC and CAISO host a public forum for long term planning, providing future scenario descriptions and data that are publicly available and can be used to estimate impacts. Our data comes directly from these sources.[12] These future scenarios typically involve varying load patterns, renewable penetration, demand response and the addition of new thermal generation capacity (typically gas turbines in simple or combined cycle).

[11] Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources, June 2012.

[12] http://www.caiso.com/planning/Pages/ReportsBulletins/Default.aspx

2.2.1 2020 CAISO Load

We use the High Load Growth assumptions and create a load duration curve around days of interest. In the High Load Growth case, CPUC Staff assumed a high load growth future, a high success of incremental demand-side programs, and Low incremental supply-side DR. The High Load Growth assumes a robust economic recovery and/or promoting policies that foster high load growth, high demand-side reductions, and low quantities of Demand Response. As shown in Table 1, we first identify days which segment the load duration curve based upon probabilities. For example, the lowest load day is Case 1 and has 0.01% probability that no load day will be lower. The Peak Hour day occurs on 7/22 and has a 99.9% probability that all load days will be lower than peak hour day[13].

Table 1: Days Selected for Analysis

Case	Note	ISO Load Rank1)	ISO Load Volatility Rank1)	Load Probability1), 2)	Wind Rank1)	PV Rank1)	Date1)	Annual Weight
Daily Cases Analyzed based upon Load Probabilities								
1	0.1% Probability CAISO Load Day	366	364	0.01%	35	86	3/28	1
2	25% Probability Load Day	281	218	25%	352	358	12/30	10
3	50% Probability Load Day	164	267	50%	321	321	1/15	28
4	75% Probability Load Day	83	78	25%	277	235	9/22	10
5	99.9% Peak Hour Day CAISO	1	11	99.9%	122	54	7/22	1
Daily Cases based upon Renewable and Load Volatility								
6	High Load Volatility Day	8	1	99%	95	70	7/14	8
7	High PV; High Wind; High Load Day	62	58	82%	27	6	5/26	10
8	High PV; Low Load Day	203	208	43%	8	1	5/7	12
9	High Wind; High PV; Middle Load Day	155	263	52%	1	11	4/16	12
10	High PV; High Wind; Low Load Day	315	365	12%	2	15	4/10	8
Total Weights								100

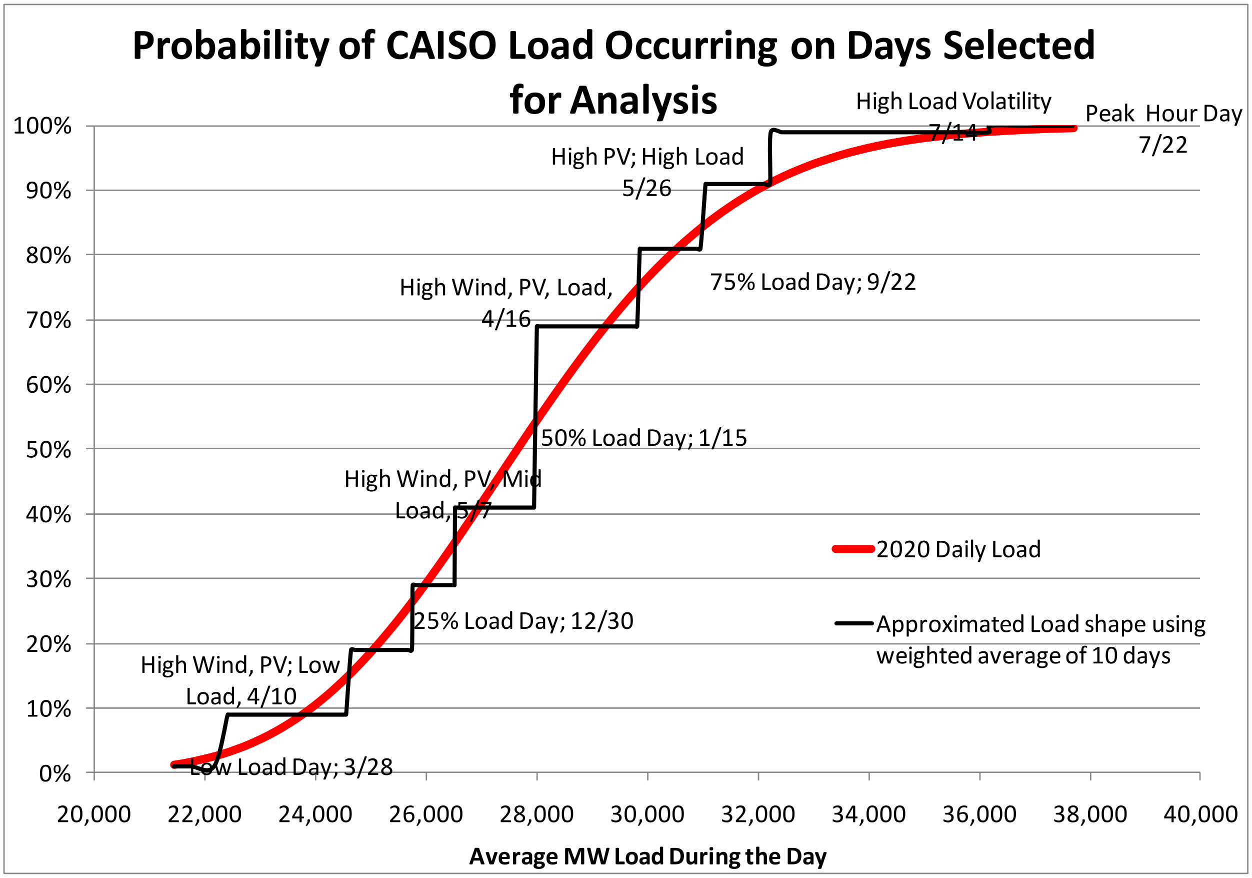
1) 1 = Highest Observed Value; 366 = Lowest Observed Value
2) Load probability is the probability that Load will be less than or equal to what is observed.
3) Weights are chosen to segment the 366 days into 10 days.

We were also interested in examining the impact of Smart Power Generation to balance energy requirements on volatile load, wind and photovoltaic (PV) days. We selected days, noted probabilities and determined weights (Table 1) to segment the load duration curve (Figure 1). Weights are used to "annualize" results and sum to 100%. For example, results from 12/30 have a weight of "10", so we

[13] We fit a lognormal probability function using Anderson Darling goodness of fit test. Stephens, M. A. (1974). EDF Statistics for Goodness of Fit and Some Comparisons, Journal of the American Statistical Association, 69, pp. 730-737.

multiply results by 10/100 and multiply by 366 days in 2020[14]. In Figure 1, we map daily CAISO loads in 2020 map weights chosen.

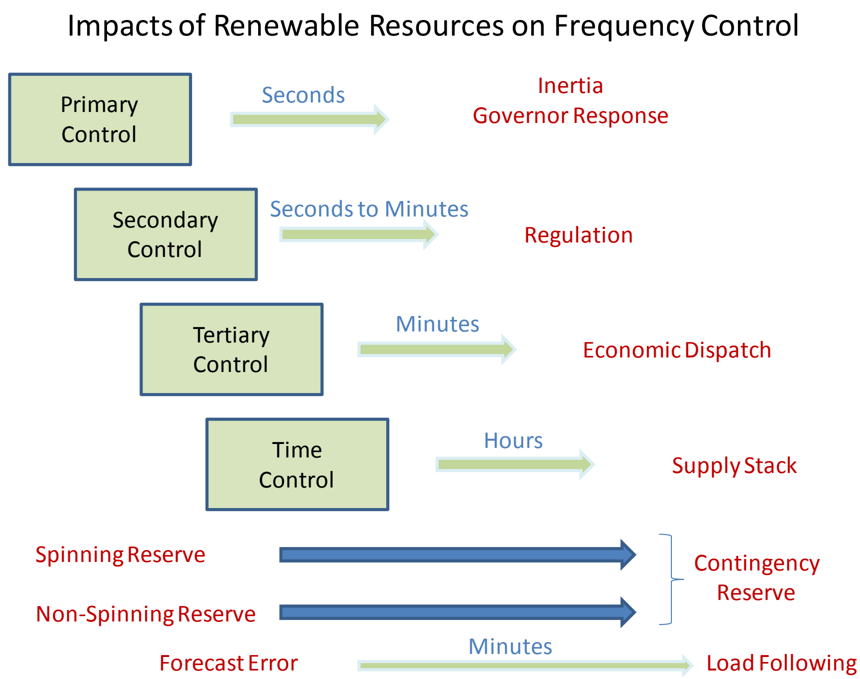
Figure 1: Probability of Those Days Occurring



[14] This technique saves simulation time relative to running 8760 hours for multiple scenarios. In earlier work we notice an error of 2.5 to 3% relative to estimating production costs using 8760 hours.

2.3 System Flexibility: Ancillary Services Needed

Figure 2: Time Line of Renewable Resource Frequency Control, after Skinner, et al, June 2012[15]



System flexibility in terms of resource control has different time domains including unit commitment, load following and regulation[16]. As represented in Figure 2, primary control is through governor control, responding in seconds. Secondary control comes from procurement of regulation resources, responding in seconds to minutes. Tertiary control involves economic dispatch in 5 minute intervals. 5 Minute Real Time Dispatch is common to most RTOs including CAISO. Unit commitment typically covers several hours to several days. Unit commitment involves the starting and synchronizing of thermal generation so that it is available when needed to meet expected electricity demand. Spinning Reserve is the on-line reserve capacity that is synchronized to the grid system and ready to meet electric demand within 10 minutes of a dispatch instruction by the ISO. Spinning Reserve is needed to maintain system frequency stability during emergency operating conditions and unforeseen load swings and is common across all North American RTOs. Non-Spinning Reserve is off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO, and that is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain system frequency stability during emergency conditions[17].

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[15] R12-03-12: 2012 LTPP Operating Reserve Analysis, June 2012.

[16] http://www1.eere.energy.gov/solar/pdfs/50060.pdf. Also see CAISO LTPP presentations for similar concepts.

[17] Settlements Guide, CAISO, revised 1/31/2006.

A new flexible ramping market has emerged in California to address the need for flexible capacity in the future. Flexible capacity has been defined by the CAISO[18] for each resource based on the resource's ramping speed, ability to sustain a ramp, ability to change ramp directions, ability to reduce output and not encounter emission limitations, start time, and ability to cycle on and off frequently. We investigate potential cost impacts of future scenarios by simulating five minute real time dispatch in Section 4.

Load following in California typically ranges from 5–15 minutes to a few hours and is associated with supplemental energy and capacity used to meet uncertainties in renewable generation and load[19]. Subject to operating constraints on the generator, units that have been previously committed or are able to start quickly can provide this service. We explore the potential impacts of load following in Section 3.

Regulation typically ranges from several seconds to 5 minutes, and covers the variability that occurs between economic dispatches. Using automatic generation control (AGC), units automatically respond to minute-by-minute load deviations in response to signals from grid operators. Changes in load and variable renewable generation during the regulation time are typically not predicted or scheduled in advance and must be met through generation that is on-line, grid-synchronized, and under automated control by the grid operator. In the short run, ramp rates describe the ability of a resource to increase (ramp up) or decrease (ramp down) generation. All operating reserves (load following and regulation) and contingency reserves (spinning and non-spinning) are ancillary services.

We used the "Environmentally Constrained Case" (Reference) to define Load Following and Regulation requirements. In the Environmentally Constrained case, the 33% Renewable Portfolio Standard is met with renewable energy supply including a higher proportion of distributed Photovoltaic (roughly 8,800 MW of distributed PV, compared to roughly 2,800 MW in the Trajectory or Base Case)[20]. Maximum and minimum hourly load following and regulation requirements for the 2020 CAISO simulations are shown in Figure 3[21].

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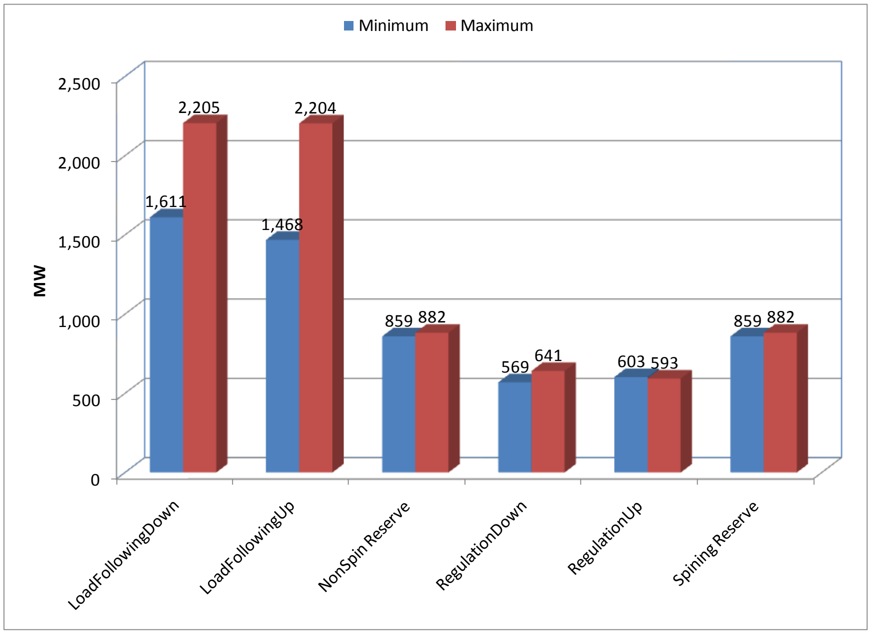
[18] Flexible Capacity Procurement Phase 1: Risk of Retirement, Market and Infrastructure Policy, Draft Final Proposal, July 26, 2012, page 16.

[19] In non-RTO environments, bilateral load following products can use hourly or other sub-hourly time domains.

[20] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf.

[21] Source: www.CPUC.org PLEXOS data files for Load Following and Regulation. Load following and Regulation from the Environmentally Constrained Case were used. We used spinning and non-spinning requirements as 3% of load requirements after CAISO, R.12-03-012: 2012 LTPP, Operating Flexibility Analysis, Nathaniel Skinner, et al, Senior Analyst, Generation & Transmission Planning, California Public Utilities Commission, June 4, 2012.

Figure 3: Hourly Maximum and Minimum Ancillary Service Requirements for CAISO in 2020



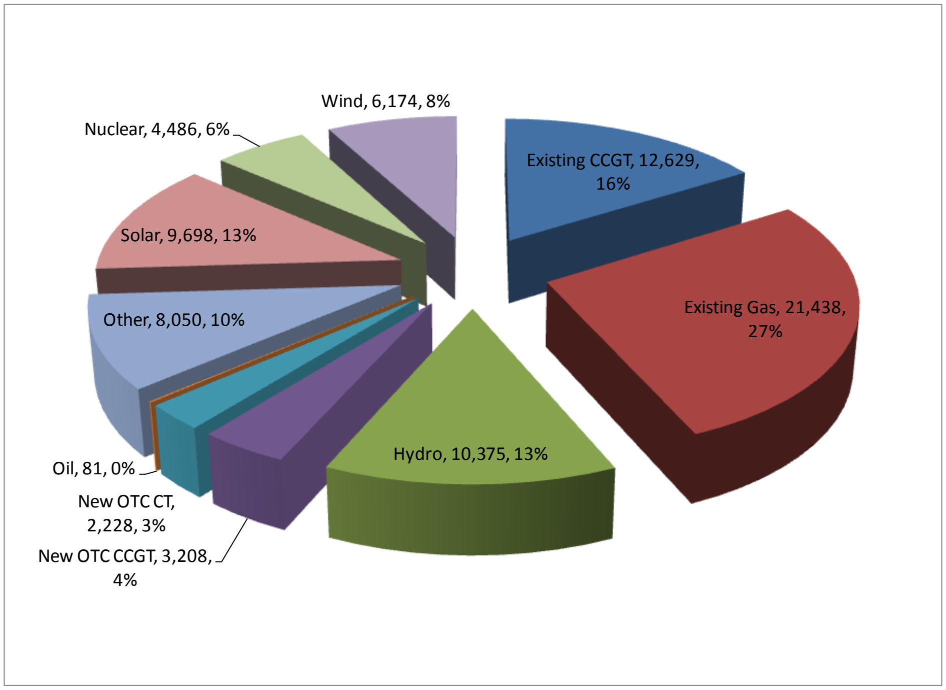
Ancillary services accounted for only $139 million in 2011. The bulk of purchases were made for regulation reserves, load following and spinning reserves. For 2020, Spinning and Non-Spinning reserves are estimated as 3% of load[22] following CAISO conventions. We used estimated requirements for load following up, load following down, regulation up, regulation down, spinning and non-spinning available for the 33% Renewable case.

2.4 2020 CAISO Generation Capacity

Using the LTPP Environmentally constrained case; 78,367 MW of CAISO generation capacity was used in for our 2020 simulations. The capacity is depicted by primary fuel type in Figure 4.

[22] R.12-03-012: 2012 LTPP Operating Flexibility Analysis, June 4, 2012. Slide 56.

Figure 4: 2020 Base Case CAISO Generation Capacity by Type, total = 78,367 MW



Following the California Public Utility Commission's (CPUC) specification of the 2020 California Electricity grid[23], we assumed 4,486 MW (6%) of nuclear, 21,438 MW (27%) of existing gas capacity, natural gas combined cycle capacity of 2,629 MW(16%), hydro capacity of 10,375 MW (13%) and in-state renewable generation consisting of wind (6,174 MW, 8%) and solar (9,698 MW or 13%). Other capacity includes biomass, distributed resources, demand response and not elsewhere classified generation.

Using the CPUC Energy Division LTPP assumptions[24], both known additions and planned additions filed with the CPUC were used. In the scenarios we used, the CPUC Energy Division Staff assumed that the new and once-through-cooling (OTC) units would be replaced (in part) by appropriate technology. While the CPUC identified some 19 GW of affected OTC units, we focused upon 5,517 MW of natural gas fired capacity not yet constructed but expected to be on-line by 2020. Imports were based on the maximum import capability of transmission into the California ISO.

In the Environmentally Constrained case, the CAISO portion of the California 33% Renewable Portfolio Standard is met with renewable energy supply including a high proportion of distributed Photovoltaic (In our scenarios roughly 8,800 MW of distributed PV was deployed compared to roughly 2,800 MW in the

[23] http://www.cpuc.ca.gov/NR/rdonlyres/6B85C614-FDF3-4EC3-A97A-70A92D2DB19A/0/2012LTPPDraftScenarios.pdf.

[24] http://www.caiso.com/Documents/Summary_PreliminaryResults_33PercentRenewable IntegrationStudy_2010CPUCLongTermProcurementPlanDocketNo_R_10-05-006.pdf

Trajectory or Base Case)[25]. In the High Load Growth case, CPUC Staff assumed a high load growth future and a high success of incremental demand-side programs that would be available if conditions warrant. There were two types of demand response which are modeled: price responsive demand response and "backstop" demand response should there be a shortfall in load or ancillary service requirements. The High Load Growth assumes a robust economic recovery and/or promoting policies that foster high load growth, high demand-side reductions, and low quantities of Demand Response. We assumed no forced or planned outages in any simulations.

2.5 2020 Smart Power Generation Parameters

We contrast (combustion engine) Smart Power Generation operating parameters with those of the repowered Once-Through-Cooling units (OTC re-powered units) in Table 2, listing new and re-powered OTC generation capacity targeted in the study[26]. New and re-powered OTC generation assumptions used for the 2020 CAISO simulation are listed along with the generator name. First, note that new and re-powered OTC assumptions have a higher maximum capacity than the smaller Smart Power Generation assumptions. With smaller units, minimum stable operating levels are lower and can be more efficient than the larger new and re-powered OTC units. Second, note that there is a difference in the fuel efficiency (heat rate) between the new and re-powered OTC units and Smart Power Generation configurations. Marsh Landing, Sentinel, Walnut Creek and Canyon Anaheim are all projected to have heat rates higher than both Smart Power simple cycle and combined cycle operating in simple cycle mode. Smart Power Generation in simple cycle mode is less efficient than new or OTC re-powered combined cycles such as Russell City Energy, Colusa Energy Center, Lodi and El Segundo, but has lower variable O&M costs and faster ramp rates. While new or OTC re-powered combined cycles are more efficient, the start costs are also significantly higher than those of the Smart Power Generation. In short, new or OTC re-powered combined cycle generators provide inexpensive energy as long as the operator is not required to start and stop them. In terms of ramping, Smart Power Generators are faster in simple cycle mode than new or OTC re-powered generators but are more efficient than the new or OTC re-powered simple cycles. Smart Power Generation multiple shaft plants can operate at part load by shutting down engines, creating flexibility in use.

[25] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf.

[26] There are many units identified by the CPUC as potential new or OTC re-powering. These are a subset of those units.

Table 2: New and OTC re-powered Generator Performance Assumptions versus Smart Power Generation Performance Assumptions

OTC Addition	Plant Capacity (MW)	Unit Capacity (MW)	Min Stable Level (MW)	Load Point 50% loading (MW)	Load Point 75% loading (MW)	Load Point 100% loading (MW)	Heat Rate 50% loading (BTU/ KWhr)	Heat Rate 75% loading (BTU/ KWhr)	Heat Rate 100% loading (BTU/ KWhr)	Max Ramp Up (MW/ min)	Max Ramp Down (MW/ min)	Min Up Time (hrs)	Min Down Time (hrs)	Start Cost ($)	VO&M Charge ($/MWhr)
Once Through Cooling Re-powering Performance Assumptions															
Marsh Landing: 760 MW in 190 x 4 CT's in simple cycle	760	190	108	108	190		12,326	10,000		13	13	2.0	1.0	$1,000.00	$5.00
Russell City Energy: CCGT 600 MW	600	600	240	240	450	600	8,280	7,500	7,080	3	3	8.0	4.0	$47,824.00	$5.70
Colusa Energy Center: CCGT 660 MW	660	660	264	264	495	660	8,280	7,500	7,100	3	3	8.0	4.0	$49,806.00	$5.70
Avenal Energy Center: CCGT - 2 GE 7FA CT's, 2 HRSG's, 1 GE ST	600	600	240	240	450	600	8,280	7,500	7,124	3	3	8.0	4.0	$28,000.00	$5.70
Lodi NCPA: CCGT - 1 Siemens STGS-5000F CT, 1 ST	255	255	80	80	175	255	8,100	7,500	7,050	8	8	6.0	6.0	$28,000.00	$5.70
El Segundo Repower 2 & 7: 530 MW in 2 x 265 MW CCGTs	530	265	106	106	212	265	9,936	8,760	7,834	3	3	8.0	4.0	$36,755.00	$5.70
Sentinel: 8 x 96.5 GE LMS 100 CT's in simple cycle	848	106	42.5	42.5	96		10,500	9,191		12	12	1.0	1.0	$1,000.00	$5.00
Walnut Creek: 5 x 100 CT's in simple cycle	500	100	40	40	100		10,500	9,191		12	12	1.0	1.0	$1,000.00	$5.00
Canyon Anaheim: 4 x 50 CT's in simple cycle	200	50	20	20	50	11700	9,800			6	6	1.0	1.0	$1,000.00	$5.00
Victoryville Hybrid: CCGT - 2 CTs 154 MW each, 2 HRSG's, 1 ST at 268 MW. Solar thermal would contribute upto 50 MW of ST. Aux plant load 13 MW	563	563	200	200			6,924			8	8	6.0	6.0	$28,000.00	$4.80
Totals	5516														
Smart Power Generation Performance Assumptions															
single 34SG engine "D", 60Hz	5500	10	3	5	7.5	10	9,513	8,847	8,526	6	14	-	0.1	$40.00	$3.50
Flexicycle (50SG engine + Steam turbine), 60Hz	5500	20	6	10	15	20	8,333	7,998	7,764	12	13	0.2	0.2	$80.00	$3.50
single 50SG engine, 60Hz	5500	19	5.7	9.5	14.25	19	9,266	8,731	8,327	12	13	-	0.1	$76.00	$3.50

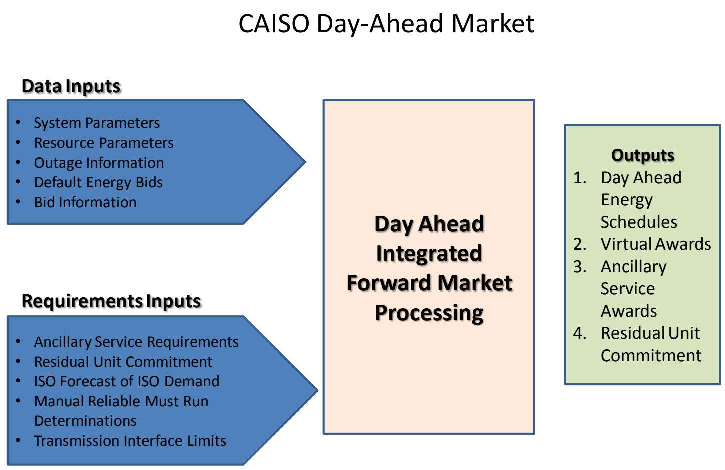
* In Scenario 2, we used 2300 MW of single cycle and 3200 MW of combined cycle Smart Power Generation

3. CAISO Hourly Day-Ahead Integrated Forward Market

In this section, we deploy the main assumptions about CAISO markets in 2020 to analyze hourly integrated day-ahead energy and ancillary service markets impacts of those assumptions across four different day-ahead scenarios. First we provide a brief description of day-ahead markets and then we describe scenarios and results.

3.1 CAISO's Day Ahead Markets

Figure 5: CAISO Day-Ahead Market Inputs, Processing and Outputs



On behalf of its members, CAISO procures energy and ancillary services to meet forecasted requirements as part of its day ahead operating procedures, depicted in Figure 5. CAISO receives resource bids from market participants and supplements that information with data from Master Files. After checking resource bids for validity, CAISO then matches resources to energy requirements and publishes awards and prices for the next operating day. With different ramp requirements and operating restrictions for various energy resources, CAISO integrates ancillary service awards with energy unit commitment awards to reduce the overall system cost of providing wholesale energy to members.

After the awards are posted, CAISO then conducts the Residual Unit Commitment to adjust any commitments to balance any short term load and generation deviations. Currently, residual unit commitment is used only to manage pre-determined system events and not used to reduce market price disruptions. Residual Unit Commitment and other processes such as virtual bids and Inter-Scheduling Coordinator transactions are not simulated in this paper.

3.2 Simulation Process, Scenarios and Metrics Evaluated

To analyze the impacts of various future 2020 conditions, we used production costing simulation. In the integrated hourly day-ahead simulations, production simulation[27] is an hourly deterministic production simulation of the entire WECC, including CAISO hourly dispatch with the objective of minimizing cost while meeting the hourly load and ancillary service requirements, subject to resource and inter-regional transmission constraints. If the production simulation is not able to meet one or more of these requirements, a shortfall is identified and generic resource capacity is introduced to resolve the shortfall. Following WECC and CPUC LTPP assumptions, we used either the General Electric LM 6000 combustion turbine or incremental Demand Response resources as a backstop against shortfalls in energy production or in ancillary services[28].

Using this product costing method, we then evaluated future market uncertainties related to renewable and distributed generation resources, generation adequacy and other related issues in these four scenarios.

1. In Day-Ahead Scenario 1 (the Base Case) we used the assumptions and architecture of the original Western Energy Coordinating Council (WECC) model. We specifically noted new or planned re-powering additions of 5.5 GW of identified Once-Through-Cooling (OTC) generation units (approximately 3.2 GW of gas turbine combined cycle, GTCC, and 2.3 GW of simple cycle gas turbines) which are assumed to be on line in 2020 and performing as specified. In our scenarios, the 5.5 GW of OTC capacity represents a potential for exploration in terms of "what-if" scenarios for system impacts; what if this 5.5 GW of OTC were supplanted or supplemented by Smart Power Generation (SPG)?

2. For Day-Ahead Scenario 2 (SPG simple cycle; no OTC) we replaced all 5.5 GW of OTC capacity with the equivalent capacity of SPG simple cycle generating sets.

3. For Day-Ahead Scenario 3 (SPG simple and combined cycle; no OTC) we replaced the 3.3 GW of new or repowered OTC gas turbine combined cycle capacity (GTCC) with 3.3 GW of Smart Power Generation combined cycles; and the new or repowered 2.2 GW of OTC simple cycle gas turbines with the equivalent capacity of Smart Power Generation simple cycle combustion engines.

4. For Day-Ahead Scenario 4 (Base + SPG) we included the 5.5 GW of OTC combustion engines in simple and combined cycle ***and*** 5.5 GW of equivalent Smart Power Generation configurations.

[27] We used the Plexos Solutions representation of the WECC Transmission Expansion Planning Policy Committee (TEPPC) model and inputs from two cases. We used the load profile from the High Load Scenario and all other inputs came from the Environmental Constraint case.

[28] TRACK I DIRECT TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION (CORRECTED), Rulemaking 10-05-006

Day-Ahead Scenario 4 represents an "overbuild" of capacity that allows the optimization algorithms to choose the least cost technology to meet energy and ancillary service needs.

The metrics we evaluated for each scenario include the following, for CAISO, for each scenario

- Variable cost of generation including fuel and operating and maintenance expenses
- Cost of Ancillary Services (i.e., load following (up and down) to account for miss-forecasted resources, regulation (up and down) which allows for automatic generation control by the ISO, spinning reserve and non-spin reserve.
- Contributions to Ancillary Service provisions by resource type
- Start/Stop costs (for all units collectively across the CAISO system)
- Emission costs (in this case, CO2 emissions)
- Capacity factors for each technology type in the CAISO system
- Dispatch profiles by technology type on select days; specifically the high volatility day (5/26) and the high load day (7/22).

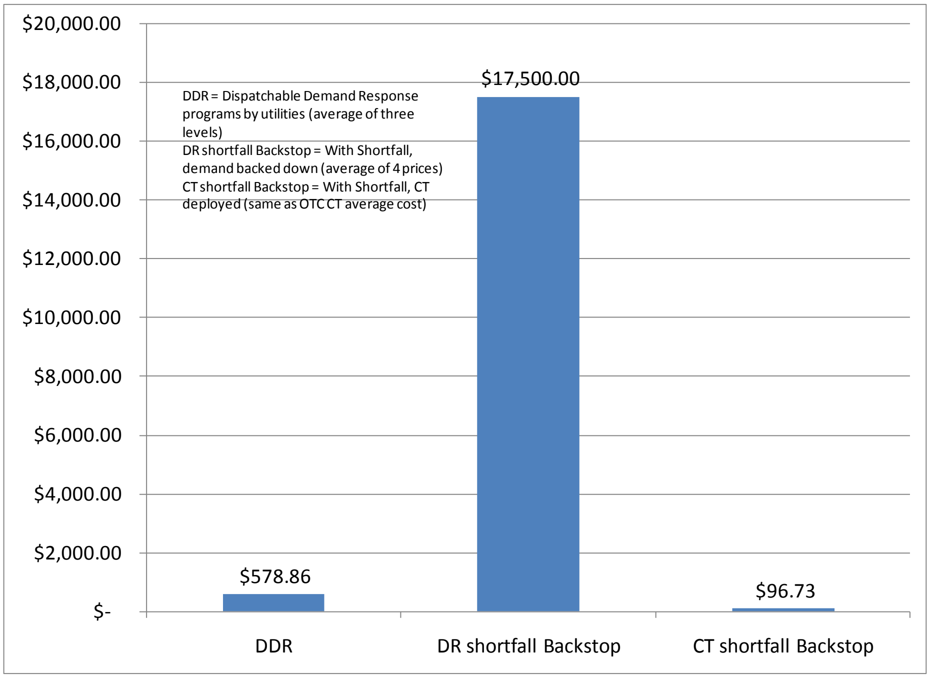
These metrics and other factors are calculated for the Base Case, and compared to results obtained for the additional scenarios. For each scenario, we explore cost impacts of meeting future market trends in 2020 with and without Smart Power Generation.

3.2.1 The Role of Demand Response in the Simulations

In the WECC model 4,815 MW of available capacity acts as Price Sensitive Demand Response (DDR) which can be invoked if prices are high enough in CAISO regions. There is no static price associated with this Demand Response. Using program cost information, the WECC model employs various blocks of potential energy savings ranging from low to high sensitivity to prices. Assuming $8/MMBTU gas prices in 2020, a high response block of DDR at 1 MMBTU/MWh would then be "dispatched" or load reduced when wholesale electricity prices reach $80/MWh. Similarly, low response blocks of DDR at 17 MMBTU/MWh would be "dispatched" or load reduced at $136/MWh with $8/MMBTU gas prices.

There is also backstop Demand Response which acts as a supplier of last resort for ancillary services. In the WECC model, 148 MW of Regulation Up and Regulation Down and 240MW of Spin/NonSpin/Load Following Up/Load Following Down are offered at the proxy price of "backing down commercial/industrial load". The WECC model has prices of $10,000/MW in the San Diego Gas and Electric Region, $15,000/MW in the Southern California Edison's region, $20,000/MW in Pacific Gas and Electric's Bay Area, and $25,000/MW in Pacific Gas and Electric's Valley region. To contrast against the Demand Response backstop, we also assume that a combustion turbine is on line and spinning and available to meet shortfalls. The generic CT is available at an average cost of $96.73/MWh (shown in Figure 6). We present this alternative to provide a contrast to what other NERC region assumptions for “backstop” are used.

Figure 6: Average Cost ($/MWh) for Demand Response and Backstop Assumptions

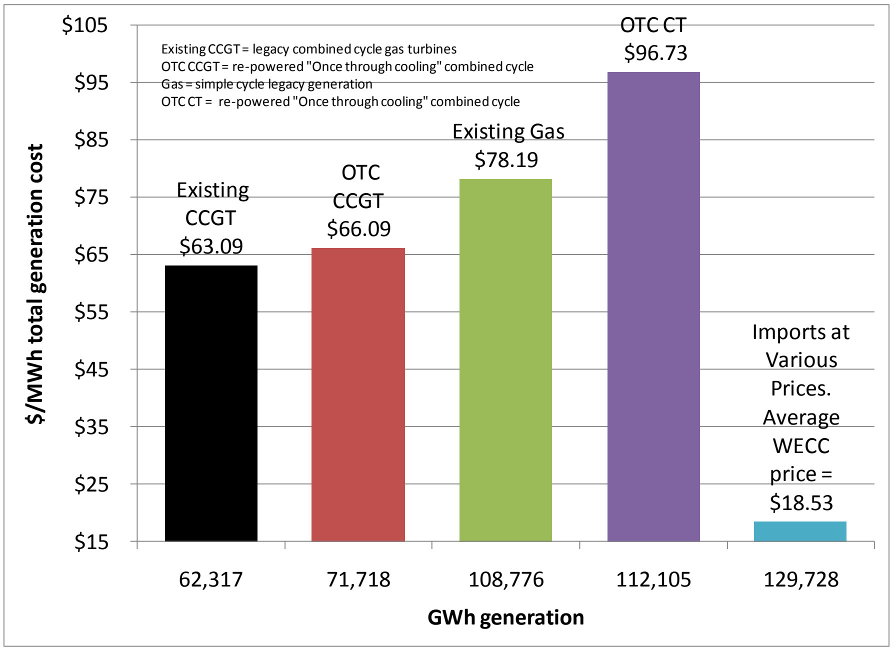


Finally, the WECC model provides for a value of load lost (penalty) is $2,000/MWh, and the value of reserve shortfall penalty is $600,000/MW. These parameters are assumptions embedded in the WECC model used by CAISO. To obtain the Ancillary Service Cost with a CT backstop, we did not re-dispatch results. Instead, we took the hours of ancillary shortfall, number of occurrences and appropriate penalty to back out the cost of Demand Response, then calculated the cost of supplying the shortfall with a generic CT at $96.73/MWh.

We did not observe any load lost penalties or transmission constraint relaxation penalties in any scenario. However, we did observe ancillary service shortfalls in three of four scenarios. We used a high load scenario coupled with environmentally constrained case resources where Demand Response supplied ancillary services (Regulation Up, Load Following Up and Spinning requirements) during our Peak Hour day scenario (7/22/20) for three of four scenarios.

3.3 Day-Ahead Scenario 1 (Base Case)

Figure 7: Day-Ahead Scenario 1 Fossil Units Supply Stack



In Day Ahead Scenario 1, we established a Base Case against which to compare future scenarios. Using the LTPP high load scenario, we dispatched resources including Once-through-Cooling (OTC) gas generation capacity which includes 3.3 GW of combined cycle and 2.3 GW of simple cycle. Existing gas generation is divided into combined cycle combustion turbines (existing CCGT) and other natural gas combustion turbine simple cycle and steam capacity (existing Gas). In all day-ahead scenarios, renewable energy schedules were forecasted and remain constant. Low cost nuclear plants are part of baseload schedules; hydro schedules are used for both energy and provision of ancillary services (primarily regulation). Demand response, oil and other generation are much higher in variable costs than natural gas so these were excluded. For the CAISO imports, we calculated the supply stack measuring generation dispatched against total generation cost. Total generation cost includes fuel and variable operating and maintenance cost plus start/stop costs plus emission cost ÷ generation for that unit. The results for specific gas costs are then plotted against total generation and shown in Figure 7.

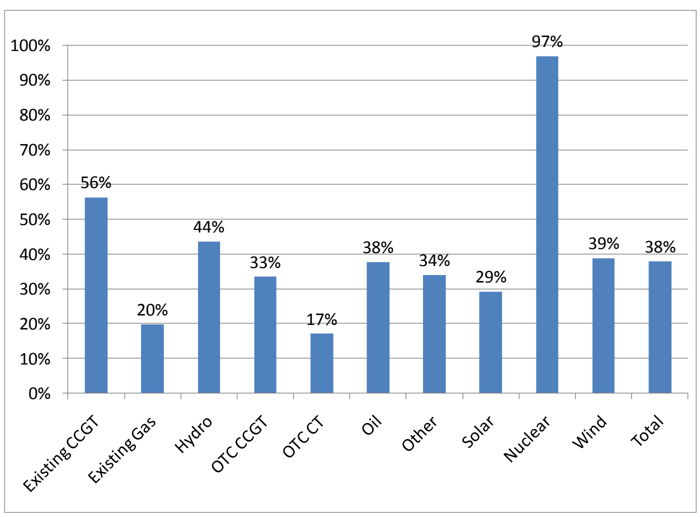
Starting and stopping costs are included in total generation costs. While combined cycle capacity offers the advantages of fuel efficiency, the higher costs to start and stop as demand fluctuates makes these units more cost effective to leave on instead of turning them off. As noted inTable 3, a comparison of start/stop costs for natural gas units shows much high costs for existing CCGT and OTC CCGT, as well as a substantial cost for existing natural gas capacity and OTC CT.

Table 3: Day-Ahead Scenario 1 Start/Stop Costs

Generation Type	Start/Stop Cost Millions ($)
Existing Natural Gas Combined Cycle (Existing CCGT)	$43
Other Existing Natural Gas capacity	$29
New and OTC Combined Cycle (OTC CCGT)	$18
New and OTC Simple Cycle (OTC CT)	$29
All Others	$42
Total	$162

Existing CCGT has the benefit of low heat rates and is relatively high in dispatch order because of this advantage (as long as starting and stopping is not frequent). During the 2020 simulation year, existing CCGT averaged a 56% capacity factor as shown in Figure 8. Existing Gas has higher heat rates and are used less frequently (about 20% of the time). OTC CCGT has a capacity factor of 33%[29] and OTC CT has a lower capacity factor of 17%. Except for nuclear (with a 97% capacity factor) and oil units (including some must run and dispatched at 38%), solar, wind, hydro and other supply schedules are forecasted without respect to price.

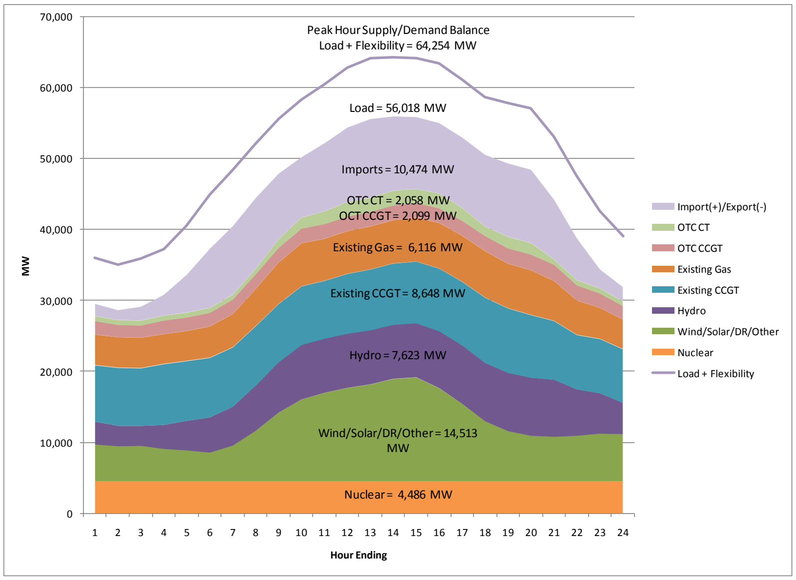
Figure 8: Day-Ahead Scenario 1 Capacity Factors by Generation Type



[29] While it may seem that the newer OTC CCGT should have a higher capacity because of more efficient units, the existing CCGT are smaller and have lower start/stop costs and in some cases relieve local congestion problems, hence are used more frequently.

In Figure 9 and Figure 10, we examine dispatch on two important days: July 22, 2020, a peak hour day; and May 26, 2020, a day with high load and renewable generation volatility. In each figure, we also display peak hour supply/demand balances to provide a reference for share of resources dispatched.

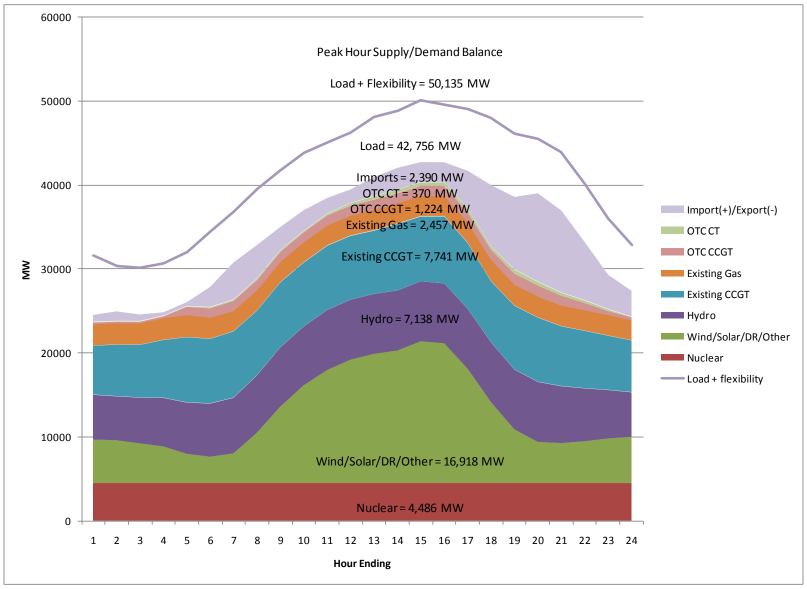
Figure 9: Day-Ahead Scenario 1 Hourly Dispatch, 7/22 Peak Hour Day



In Figure 9, we show generation dispatched to meet load and flexibility (ancillary service requirements[30]) for Peak Hour Day (7/22). Nuclear generation is base-loaded, with little hourly change in dispatch. Wind/solar/demand response (DR) and other generation create hourly fluctuations and generally ramp during the day and fall off in the evening. Hydroelectric generation is used to smooth fluctuations in wind/solar schedules. Existing CCGT and OTC CCGT have a somewhat consistent dispatch, while existing gas and OTC CT are ramped to accommodate load and wind/solar fluctuations. Note that net imports adjust to meet load and ancillary service requirements within transfer limits.

[30] There is some different definitions of flexibility (some definitions include only load following up, spinning and regulation up as flexibility). Here we just sum ancillary service requirements for ease of exposition.

Figure 10: Day-Ahead Scenario 1 Hourly Dispatch, 5/26 High Variability Day



For the high variability day (5/26) there are differences in dispatch as shown in Figure 10. The variation in the renewable generation resource (solar/wind/DR and other) is more pronounced. Load is lower on peak hour day but flexibility requirements increase; this day is interesting because it requires more balancing (ramping and start/stop of resources). On this day, nuclear is still base-loaded while hydroelectricity serves to meet energy and match wind/solar fluctuations. We note that all gas capacity is dispatched less in the 5/26 scenario, since it is higher cost than other non-gas resources and less is needed. OTC CT is still dispatched to meet energy requirements; because of smaller unit size makes these units less expensive to start for ramping purposes. On this day, imports are far less than on peak day.

In Table 4, we show ancillary service costs. Ancillary service requirements include regulation, load following, spinning and non-spinning reserves. Each of these ancillary services 2020 forecasted requirements are part of the energy and ancillary service cost minimization algorithm. In order to meet load obligations, we use the same forecasted regulation (up and down) requirements and load following (up and down) consistent with generation capacity assumptions in this environmentally constrained WECC case. Spinning and Non-spinning capacity is forecasted as 3% of hourly load, consistent with WECC assumptions.

Table 4: Day-Ahead Scenario 1 Ancillary Service Costs

Ancillary Service Costs	Base Case using DR Backstop	Base Case using CT Backstop
Load Following Up Cost (millions $)	484	463*
Load Following Down Cost (millions $)	244	
Regulation Up Cost (millions $)	126	
Regulation Down Cost (millions $)	55	
Spinning Cost (millions $)	219	
Non-Spinning Cost (millions $)	74	
Total Ancillary Service Cost (millions $)	1,201	

*Estimated by backing out Demand Response backstop costs and replacing hours with the cost of a CT.

Following Long Term Planning Assumptions, we dispatch units to minimize the cost of delivered energy and ancillary services to the customer subject to generator operating constraints, transmission constraints and the ability to meet load and ancillary service requirements. When ancillary service requirements are not met, we must use a backstop, or resource which is used to supply the shortage. In our Base Case, we found that there is a shortfall of Load Following Up, Regulation Up and Spinning Reserves. Following the WECC model assumptions, Demand Response is used to supply the shortfall hours, resulting in high costs for ancillary services. In other areas or under different conditions, cheaper resources such as a generic combustion turbine (CT) can also be used. In Table 4, we also describe the costs of meeting Base Case shortfalls, first with a DR backstop and then with a generic CT backstop.

Table 5: Day Ahead Scenario 1 Ancillary Service Contribution

Ancillary Service	Contributed By…						
	Existing CCGT	Existing Gas	Hydro	OTC Combined Cycle	OTC Simple Cycle	Demand Response	Total
Load Following Up	48%	20%	9%	8%	14%	1%	100%
Load Following Down	76%	9%	7%	7%	1%	0%	100%
Regulation Up	13%	1%	38%	13%	34%	1%	100%
Regulation Down	27%	22%	38%	12%	1%	0%	100%

Table 5 shows percent of total hours of primary ancillary service resources contributed to the load following and regulation in Day Ahead Scenario 1 (Base Case). The primary contributor to load following up and down is existing CCGT. These smaller units with high ramping and low start/stop costs are ideal to provide minute by minute response to system conditions. Hydro resources provide significant Regulation Up and Down. Regulation Up is also provided by OTC CT in significant quantities as well as other gas capacity. Because there is a shortfall in the Base Case for Regulation Up, Load Following Up and Spinning Reserves, Demand Response backstop is deployed.

In 2011, CAISO ancillary service costs were estimated to be $139 million[31]. Without shortages, load following requirements alone are expected to triple by 2020 due to increased penetration of renewable resources, higher levels of demand response and related system contingencies. Using a backstop such as a combustion turbine, ancillary service costs are projected to increase by 233% to $463 million. With ancillary service shortages and using expensive demand response as the backstop, costs could rise as high as $1201 million. In using a CT as backstop, we did not re-dispatch any solutions, which may also offer additional cost savings.

Table 6 summarizes the Base Cost costs by major cost category.

Table 6: Day-Ahead Scenario 1 CAISO Production Cost Summary

Cost Category	Base Case Costs in Millions $
CAISO Variable Generation Cost	$ 4,963
CAISO Start/Stop Cost	$ 179
CAISO Emission Cost	$ 1,463
Total CAISO Generation Cost	$ 6,605
Imports from other regions*	$ 327
Subtotal Energy Cost	$ 6,932
Ancillary Service cost with DR backstop	$ 1,201
Total Cost to Serve CAISO Load with DR Backstop	$ 8,133
Ancillary Service Cost with CT backstop	$ 463
Total Cost to Serve CAISO Load with CT Backstop	$ 7,395

*Imports from other regions totaled 17,623 GWh, using a weighted average WECC cost of $18.53/MWh; we calculated cost of imports to be about $327 Million.

Variable generation costs include fuel and operating and maintenance costs. Start/Stop costs have been detailed above. Emission costs are calculated as CO2 emissions per plant multiplied by a tax of $42.46/ton of CO2 emitted.[32] Total generation costs of $6,605 million are the sum of these categories. Some of the most expensive resource categories are those resources dispatched to meet both load following and regulation requirements. Load following meets potential forecast variations in both load and forecasted renewable generation and tallies $484 million for Load Following Up and $244 million for Load Following Down. From our discussion above, we note that ancillary service costs have a range of estimates depending upon which resource is used to backstop the shortfall. With Demand Response backstopping the shortfall, $1,201 million is projected for ancillary services, creating a total cost to serve load of $8,133 million in 2020. With a generic CT as a backstop, the ancillary service costs drop to $348 million and the total cost to serve load is $7,395 million in 2020.

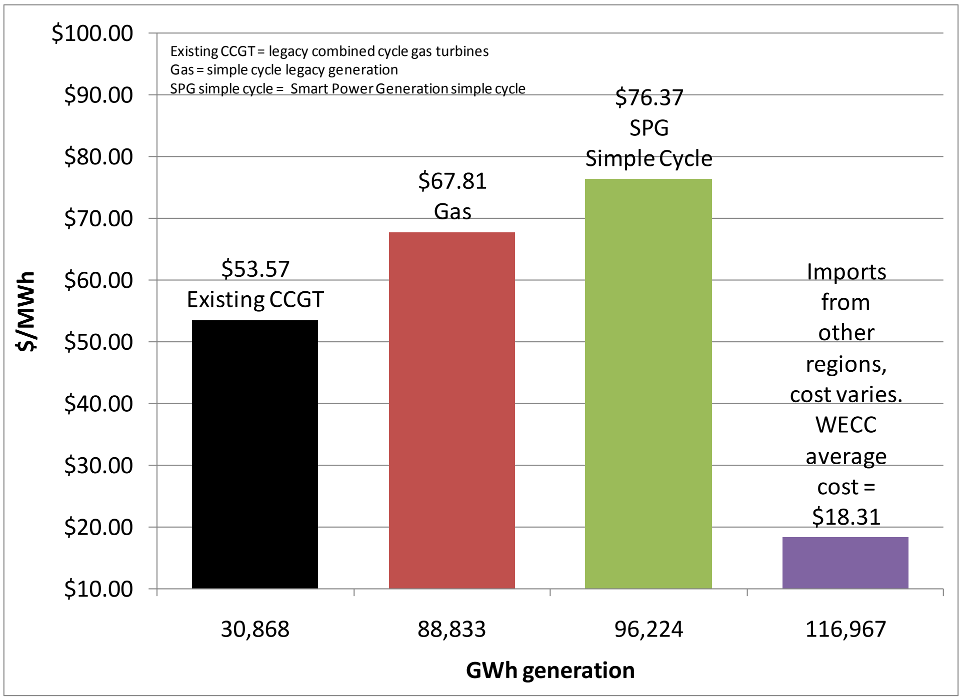
[31] CAISO, Department of Market Monitoring, April 2012.

[32] INPUTS AND ASSUMPTIONS TO 33% RENEWABLES PORTFOLIO STANDARD IMPLEMENTATION ANALYSIS, Energy and Environmental Economists, Inc, June 2010

3.4 Day Ahead Scenario 2 (SPG Simple Cycle; No OTC)

We evaluated this scenario to explore how replacing the 5.5 GW of new or repowered OTC units in the WECC model with Smart Power Generation simple cycle units would impact CAISO system costs. We re-simulated the 2020 Study year, and then analyzed market results.

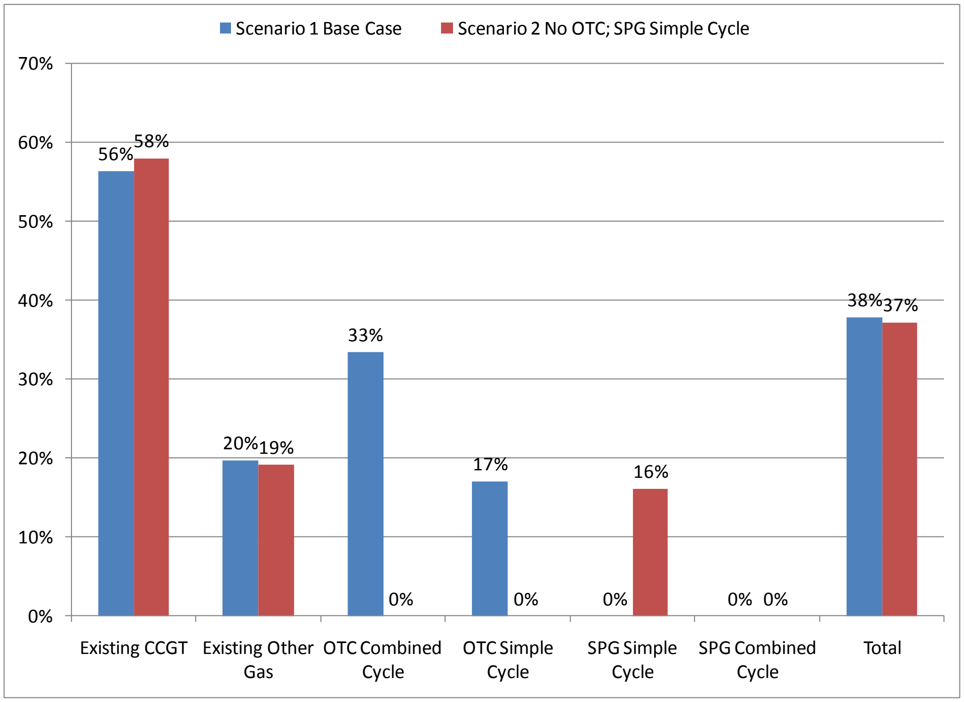
Figure 11: Day-Ahead Scenario 2 Supply Stack



As shown in Figure 11, displacing 5.5 GW OTC simple and combined cycle capacity with 5.5 GW Smart Power Generation simple cycle units creates lower total generation costs for existing CCGT and less dispatch when compared to the Base Case. Relative to existing CCGT, SPG Simple Cycle has lower start/stop costs and provides quicker ramping which explains some of both the drop in total cost and less dispatch. The other reason is that SPG is modular in design and has smaller start/stop loadings to ramp to volatile profiles. By displacing OTC units with SPG simple cycle units, fewer start and stops are required for existing CCGT, making them more efficient and lowering average cost.

Relative to the Base Case, existing gas capacity has a slightly lower cost ($67.68/MWh versus $78.19/MWh) due to a smaller number of starts and stops (for balancing). SPG simple cycle displaces the start/stop and ramping functions in existing gas units. But perhaps the largest change is the increased amount of net imports when OTC capacity is removed. On the margin, there is significant gas import capacity from neighboring regions which is used to reduce costs of energy and ancillary services in Day-Ahead Scenario 2. We did not observe any transfer limit violations and transmission utilization increased in Day-Ahead Scenario 2.

Figure 12: Capacity Factors: Day-Ahead Scenario 1 versus Scenario 2



The amount of net imports also explains some of the differences observed in capacity factors when comparing Base Case to Scenario 2 (SPG Simple Cycle; No OTC) in Figure 12. In Scenario 2, overall capacity factors decline due to increased net imports. We find that SPG simple cycle displaces existing CCGT and other gas capacity. We find that while SPG Simple Cycle provided cost savings and these savings are slightly offset by higher import costs than in the Base Case.

Table 7: Day-Ahead Scenario 2 Start/Stop Cost versus Base Case

Generation Type	Scenario 2 Start/Stop Cost Millions ($)	Base Case Start/Stop Cost Millions ($)
Existing Natural Gas Combined Cycle	$28	$43
Other Existing Natural Gas capacity	$18	$29
New and OTC Combined Cycle	N/A	$18
New and OTC Simple Cycle	N/A	$29
Smart Power Generation Simple Cycle	$14	N/A
All Others	$38	$42
Total	$98	$162

As shown in Table 7, total start costs are $98 million versus $162 million for the Base Case. Most of the cost reduction comes in reducing existing CCGT and existing natural gas capacity start and stops compared to the Base Case.

Figure 13: Day-Ahead Scenario 2 Hourly Dispatch, 7/22 Peak Hour Day

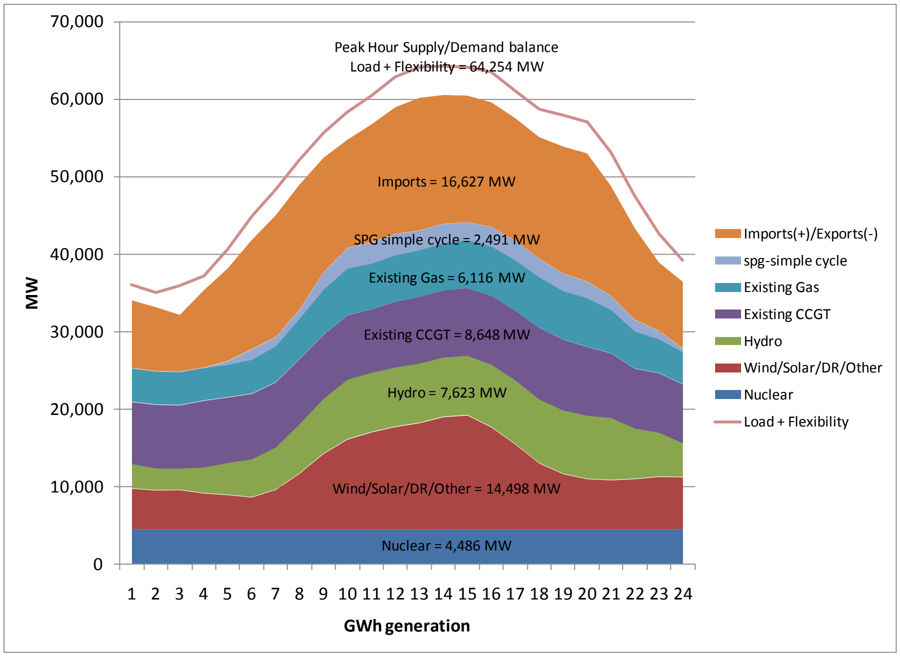
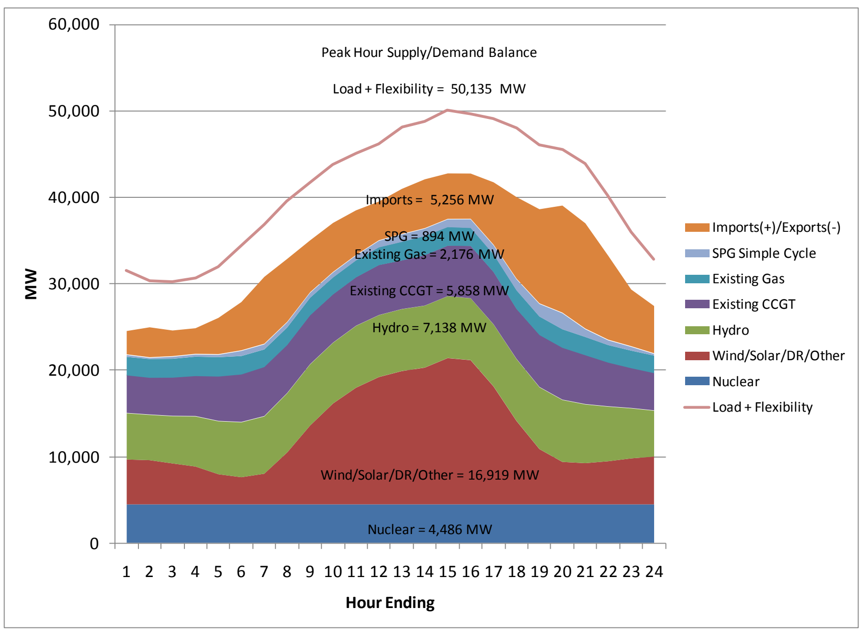


Figure 13 shows dispatch by resource in Scenario 2 (SPG Simple Cycle; No OTC) for Peak Hour day on July 22, 2020. The load and flexibility requirements remain the same as in the Base Case, but the generation mix changes. Instead of 5.5 GW of OTC simple and combined cycle capacity, we make available 5.5 GW of Smart Power Generation (SPG) simple cycle. Instead of about 4 GW of OTC at peak hour, we only use about 2.5 GW of SPG simple cycle and import from neighboring regions.

Figure 14: Day-Ahead Scenario 2 Hourly Dispatch, 5/26 High Variability Day



Similarly for Scenario 2 (SPG Simple Cycle; No OTC) on 5/26 peak hour, we find that in place of 1.6 GW of OTC generation at peak hour, only 0.9 GW of SPG simple cycle is used and the remaining portion is imported. This dispatch result is shown in Figure 14 where we import 5,256 MW on peak hour in Scenario 2 (SPG Simple Cycle; No OTC) versus 2,390 MW in the Base Case.

Table 8: Day-Ahead Scenario 2 Ancillary Service Costs

Ancillary Service Costs	Scenario 2 using DR Backstop	Base Case using CT Backstop
Load Following Up Cost (millions $)	261	447*
Load Following Down Cost (millions $)	93	
Regulation Up Cost (millions $)	77	
Regulation Down Cost (millions $)	34	
Spinning Cost (millions $)	131	
Non-Spinning Cost (millions $)	13	
Total Ancillary Service Cost (millions $)	609	

*Estimated by backing out Demand Response backstop costs and replacing hours with the cost of a CT.

Table 8 summarizes Ancillary Service costs by type for Scenario 2. We note that a smaller portion of Demand Response still supplies a shortfall in ancillary services in Scenario 2 and that cheaper imports supply some of the energy and ancillary service requirements instead of OTC capacity. Note that we did not increase system capacity – just replaced one type of generation with another.

Table 9: Day-Ahead Scenario 2, Ancillary Service Contribution

Ancillary Service			Contributed By…						
	Existing CCGT	Existing Gas	Hydro	OTC Combined Cycle	OTC Simple Cycle	SPG simple cycle	SPG combined cycle	Demand Response	Total
Load Following Up	27%	7%	8%	N/A	N/A	57%	N/A	<1%	100%
Load Following Down	46%	16%	7%	N/A	N/A	31%	N/A	0%	100%
Regulation Up	4%	<1%	19%	N/A	N/A	77%	N/A	<1%	100%
Regulation Down	26%	21%	38%	N/A	N/A	15%	N/A	0%	100%

Table 9 shows the contribution to ancillary service by resource type for Scenario 2 (SPG simple cycle; No OTC). From the table, we find that a majority of Load Following and Regulation Up requirements are met by SPG simple cycle. Regulation Down is primarily supplied by Hydro; and existing CCGT supply Load Following Down.

To summarize Scenario 2, we still had a shortfall in ancillary services. Therefore, we made two calculations for ancillary service cost to compare to Base Case – one in which Demand Response

provided a backstop for shortfall and one in which a generic CT provided reserve shortfall. Smart Power Generators are being chosen based on reduced energy costs for dispatch, offset of start costs, and lower cost ancillary services, as can be shown in
Table 10.

Table 10: Day-Ahead Scenario 2 CAISO Production Cost Summary

Cost Category	Scenario 2 Costs in Millions $	Percent Change from Base Case
CAISO Variable Generation Cost	$ 4,778	-4%
CAISO Start/Stop Cost	$ 99	-44%
CAISO Emission Cost	$ 1,402	-4.2%
CAISO Total Generation Cost	$ 6,279	-5%
Imports from other regions*	$ 380*	+14%
Subtotal Energy Supply Cost	$ 6,659	-3.9%
Ancillary Service cost with DR backstop	$ 609	-49%
Total Cost to Serve CAISO Load with DR Backstop	$ 7,268	-11%
Ancillary Service Cost with CT backstop	$ 447	-3.5%
Total Cost to Serve CAISO Load with CT Backstop	$ 7,106	-3.9%

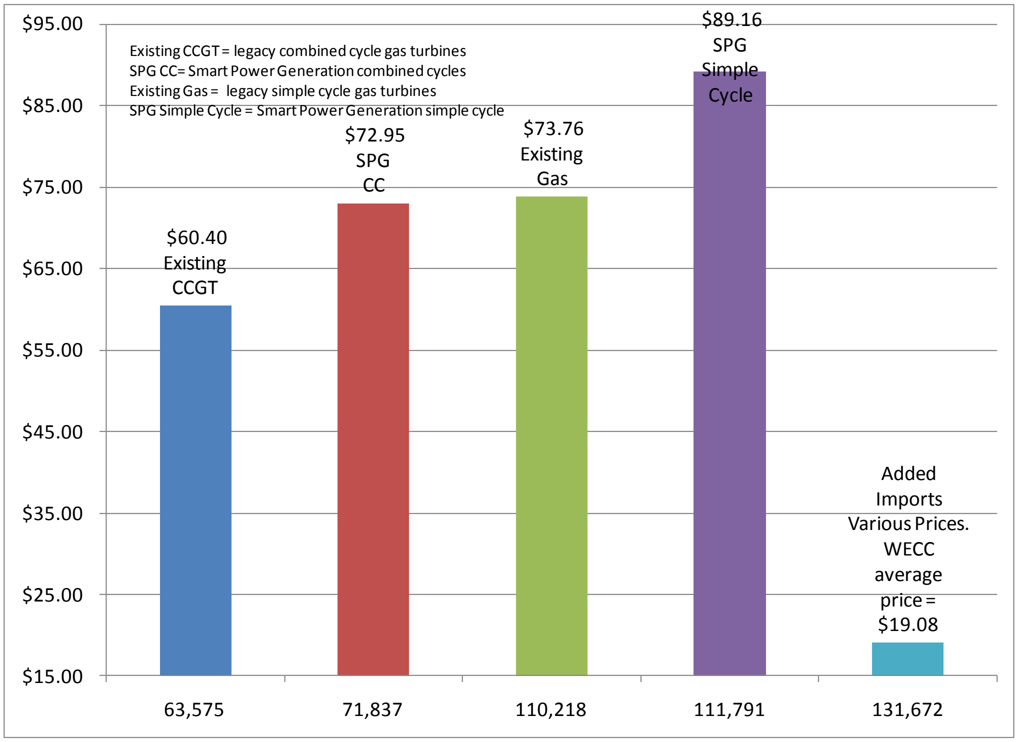
*Imports from other regions totaled 20,743 GWh, using a weighted average WECC cost of $18.31/MWh; we calculated cost of imports to be about $380 Million.

Overall, Smart Power Generation simple cycle greatly reduced costs to deliver energy and ancillary services in Scenario 2 when compared with the Base Case. Faster and cheaper ramping and start/stop costs required to meet energy and ancillary services over existing natural gas capacity are the primary reason. There are substantial cost savings in start/stop and savings in variable costs drive reductions in CO2 emissions cost.

3.5 Day-Ahead Scenario 3 (SPG simple and combined capacity; No OTC)

In this scenario we examine the market impacts of introducing both simple and combined cycle Smart Power Generation capacity in place of OTC simple and combined cycle configurations. For Day-Ahead Scenario 3, we displace 3.3 GW of OTC CCGT capacity with 3.3 GW of Smart Power combined cycle generation capacity. We also displace 2.2 GW of OTC CT with 2.2 GW of Smart Power Generation simple cycle capacity. After simulating day-ahead markets, we then compare metrics. As shown in Figure 15, the introduction of Smart Power Generation combined cycle alters the supply stack.

Figure 15: Day-Ahead Scenario 3 Supply Stack



Relative to Day Ahead Scenario 1 (Base Case), existing CCGT are started and stopped less than in the base case, lowering average cost ($63.09/MWh versus $60.40/MWh). Smart Power Generation combined cycle displaces existing gas units in merit order ($72.95/MWh versus $73.16/MWh) because they are more efficient to run and start/stop. The Smart Power Generation simple cycle displaces OTC CT along with an increase in imports. There are still more imports in this case than in Day Ahead Scenario 1, the Base Case. In the Base Case, cheaper OTC units were used; in this case, imports were cheaper to use.

Table 11: Day-Ahead Scenario 3 Start/Stop versus Base Case

Generation Type	Scenario 3 Start/Stop Cost Millions ($)	Base Case Start/Stop Cost Millions ($)
Existing Natural Gas Combined Cycle	$7	$43
Other Existing Natural Gas capacity	$28	$29
New and OTC Combined Cycle	N/A	$18
New and OTC Simple Cycle	N/A	$29
Smart Power Generation Simple Cycle	$29	N/A
Smart Power Generation Combined Cycle	$5	N/A
All Others	$27	$42
Total	$96	$162

In Day Ahead Scenario 3, introducing a mix of Smart Power Generation combined and simple cycle capacity in place of OTC combined and simple cycle used in the Base Case creates lower start/stop costs as shown in Table 11. Lower start/stop costs favor the Smart Power Generation and Existing Natural Gas simple cycle, which is used more frequently than combined cycles (already deployed to meet energy requirements). We also note that in Day Ahead Scenario 3, Smart Power Generation reduces start/stop costs for existing natural gas combined cycle as well as all other unit start/stop costs.

Figure 16: Day-Ahead Scenario 3 Capacity Factors

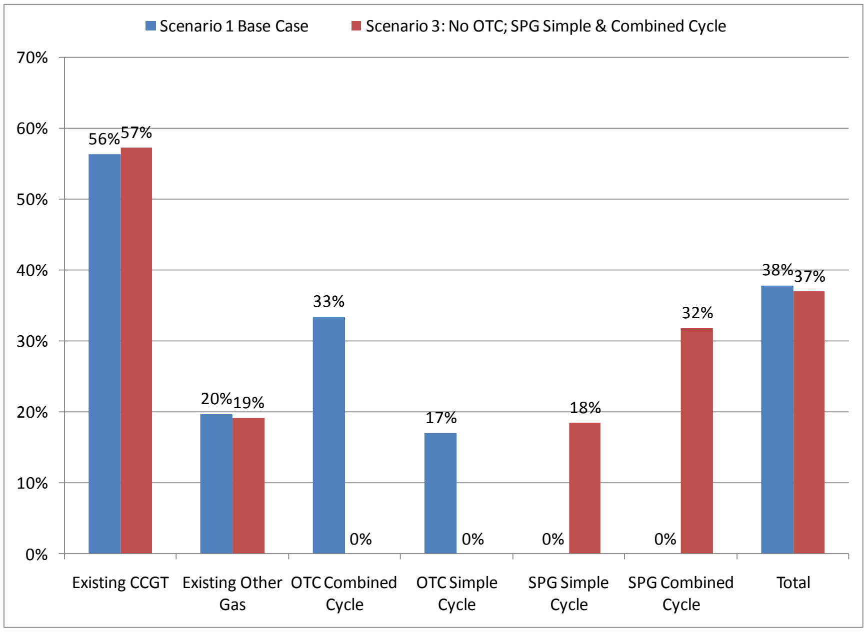
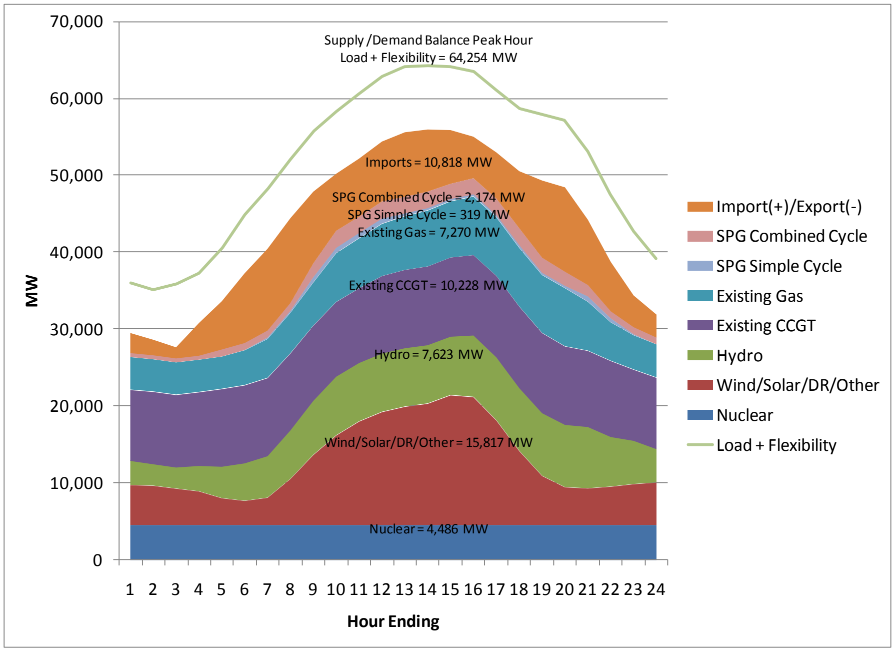


Figure 16 shows capacity factors for CAISO generation units in Scenario 3 (SPG simple and combined cycle; No OTC). Overall, capacity factors for CAISO generation drop slightly when compared to the Base Case because more imports are used in Scenario 3. OTC Simple and Combined Cycle capacity replaces displaced OTC capacity for both simple and combined cycle.

Figure 17 shows 7/22 Peak Hour dispatch to meet load and flexibility requirements (where flexibility includes all ancillary services). Relative to Base Case, we have slightly more imports in Scenario 3; neighboring generation is slightly less expensive than SPG simple cycle generation. Smart Power Generation still supplies about 2,400 MW during peak; but most of it comes from more cost efficient combined cycle capacity.

Figure 17: Day-Ahead Scenario 3 Dispatch, 7/22 Peak Hour Day



In Figure 18 dispatch for high variability days shows that peak hour supply and demand balances are met with slightly more imports. Displaced OTC simple and combined cycle generation is partially met by SPG simple cycle generation and partially by imports.

Figure 18: Day-Ahead Scenario 3 Dispatch, 5/26 High Variability Day

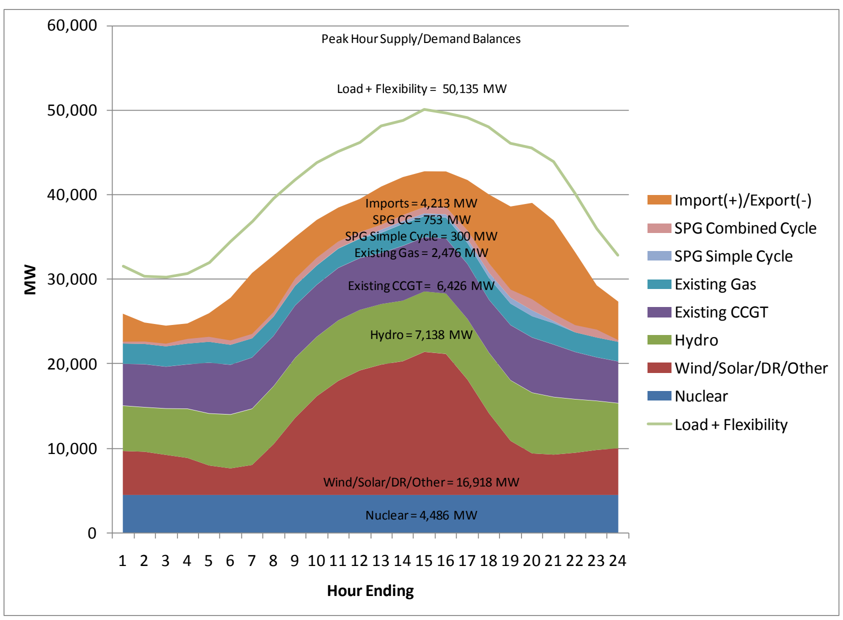


Table 12 shows Ancillary Service costs for Scenario 3 with both Demand Response and CT as a backstop to the reserve shortfall. Load following up contributes the largest share of ancillary service costs.

Table 12: Day-Ahead Scenario 3 Ancillary Service Costs

Ancillary Service Costs	Scenario 3 using DR Backstop	Base Case using CT Backstop
Load Following Up Cost (millions $)	254	441*
Load Following Down Cost (millions $)	105	
Regulation Up Cost (millions $)	72	
Regulation Down Cost (millions $)	33	
Spinning Cost (millions $)	126	
Non-Spinning Cost (millions $)	13	
Total Ancillary Service Cost (millions $)	603	

*Estimated by backing out Demand Response backstop costs and replacing hours with the cost of a CT.

Relative to the Base Case, Scenario 3 (SPG simple and combined cycle; No OTC) shows large reductions in Load Following Up, Regulation Up and Spinning costs. SPG combined cycle is the major contributor for Load Following Up and Regulation Up, while Existing CCGT is a heavier contributor to Load Following Down and hydro is still the major contributor to Regulation Down. This pattern is consistent with what we observed earlier. SPG has sufficient bandwidth to supply energy (note that imports decrease slightly in this case) and is low cost provider of ancillary services.

Table 13: Day-Ahead Scenario 3, Contributions to Ancillary Services

Ancillary Service	Contributed By…								
	Existing CCGT	Existing Gas	Hydro	OTC Combined Cycle	OTC Simple Cycle	SPG simple cycle	SPG combined cycle	Demand Response	Total
Load Following Up	20%	7%	8%	N/A	N/A	15%	50%	<1%	100%
Load Following Down	75%	13%	7%	N/A	N/A	<1%	5%	0%	100%
Regulation Up	2%	<1%	17%	N/A	N/A	15%	67%	<1%	100%
Regulation Down	21%	28%	38%	N/A	N/A	<1%	23%	0%	100%

In Table 13, Scenario 3 contributions to Ancillary Service by type of resource are summarized. Introducing SPG combined cycle capacity changes the main supplier of Load Following Up and Regulation Up to SPG Combined Cycle. Once on line, the fuel efficiency savings favor this resource. Existing CCGT provided the largest share of Load Following Down while Hydro provided Regulation Down.

In Table 14, Scenario 3 costs are summarized.

Table 14: Day-Ahead Scenario 3 Production Cost Summary

Cost Category	Scenario 3 Costs in Millions $	Percent Change from Base Case
CAISO Variable Generation Cost	$ 4,764	-4%
CAISO Start/Stop Cost	$ 96	-46%
CAISO Emission Cost	$ 1,401	-4.2%
CAISO Total Generation Cost	$ 6,261	-5%
Imports from other regions*	$ 379*	+14%
Subtotal Energy Cost	$ 6,640	-4.2%
Ancillary Service cost with DR backstop	$ 603	-49%
Total Cost to Serve CAISO Load with DR Backstop	$ 7,243	-11%
Ancillary Service Cost with CT backstop	$ 441	-12%
Total Cost to Serve CAISO Load with CT Backstop	$ 7,081	-4.2%

*Imports from other regions totaled 19,881 GWh, using a weighted average WECC cost of $19.08/MWh; we calculated cost of imports to be about $379 Million.

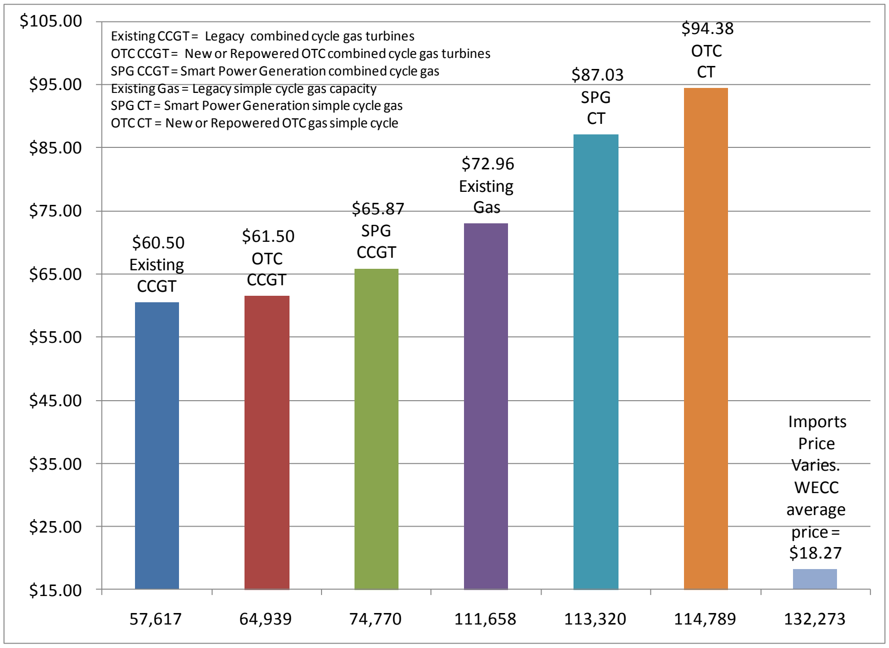
Relative to the Base Case, Day-Ahead Scenario 3 (SPG simple and combined cycle; No OTC) shows large changes in start/stop costs and in the provision of Ancillary Services with either Demand Response or a generic Combustion Turbine as backstop to meet Ancillary Services shortfall. Adding SPG simple and combined cycle (in place of OTC) lowers costs of energy supply and ancillary services about 4% relative to the Base Case.

3.6 Day Ahead Scenario 4 (SPG + Base Case)

In this scenario, we wanted to explore the least cost case of meeting energy and ancillary service requirements in 2020. To Base Case Capacity we added 3.3 GW of SPG combined cycle and 2.2 GW of SPG simple cycle capacity. This was an exploratory simulation to understand what would happen if the CAISO capacity were “overbuilt” and the optimization algorithms could choose, for every hour, the least cost mix of energy in MWh (for both energy and Ancillary Services) where both traditional OTC (gas turbine based) and SPG units were available for dispatch. After re-dispatching these units, we then analyzed results.

In Figure 19, we display dispatch and average total cost of dispatch in a supply stack. Relative to Base Case, Scenario 4 (OTC and SPG simple and combined cycles) shows lower costs for each natural gas capacity grouping. Existing CCGT is lower, OTC and SPG combined cycles are lower and SPG and OTC simple cycle is also cheaper. Because these units are more efficiently utilized, the new mix of CAISO resources becomes a net exporter to other non-CAISO regions.

Figure 19: Day-Ahead Scenario 4, Supply Stack



As shown in Figure 20, capacity was utilized differently than in the Base Case. Capacity for Existing CCGT and other gas capacity dropped as did OTC generation. Filling the void was SPG simple and combined cycle. Further, because the natural gas generation was used more efficiently, lowering total cost, CAISO becomes a net generator to other regions, raising the capacity factors for CAISO generators.

Figure 20: Day-Ahead Scenario 4 Capacity Factors versus Base Case

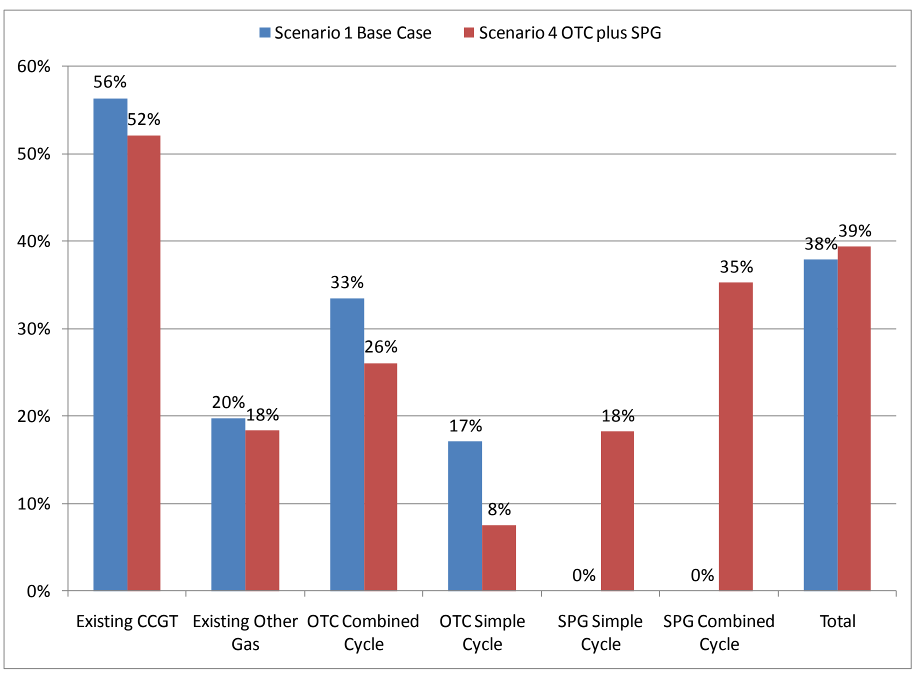
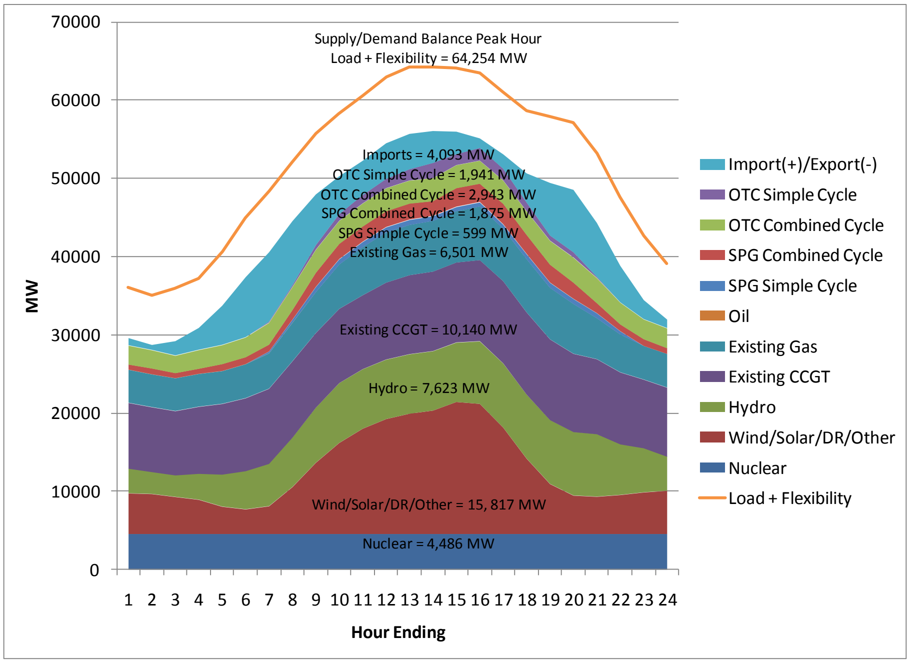


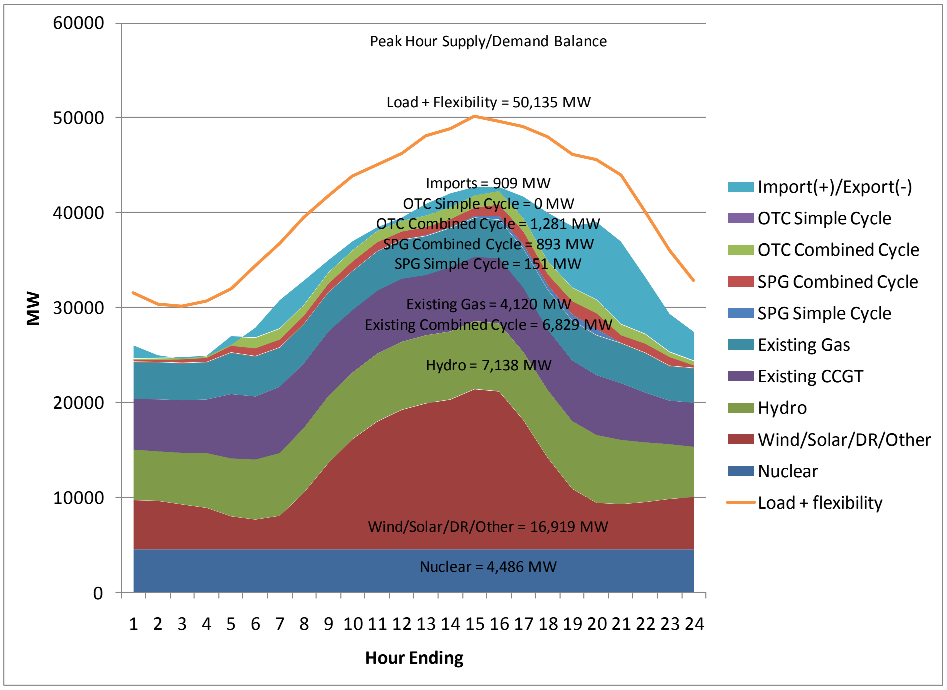
Figure 21 shows peak hour day (7/22) dispatch in Scenario 4 (SPG and OTC). Imports on peak day drop substantially compared to the Base Case. Further note that both SPG and OTC are used in dispatching energy and Ancillary Services. Both OTC simple and combined cycle capacity factor drops when SPG simple and combined cycle capacity is introduced to the Base Case resource mix. While CAISO still imports from other regions, imports are less than in the Base Case, driving CAISO total capacity factors up.

Figure 21: Day-Ahead Scenario 4 Dispatch, 7/22 Peak Hour Day



In Figure 22, dispatch during the high wind/solar and load variability day (5/26) shows that on some hours, CAISO exports to other regions as well as imports to balance wind and solar variability. Further, we note that OTC simple cycle is not needed across peak hour on this day; SPG simple cycle is sufficient to balance load and renewable generation volatility requirements.

Figure 22: Day-Ahead Scenario 4 Dispatch, 5/26 High Variability Day



As shown in Table 13, there is no shortfall for Ancillary Services in the Day Ahead Scenario 4. Relative to the Base Case, costs for providing Ancillary Services are significantly less.

Table 15: Day-Ahead Scenario 4 Ancillary Service Costs

Ancillary Service Costs	Scenario 4
Load Following Up Cost (millions $)	$191
Load Following Down Cost (millions $)	$59
Regulation Up Cost (millions $)	$55
Regulation Down Cost (millions $)	$21
Spinning Cost (millions $)	$96
Non-Spinning Cost (millions $)	$2
Total Ancillary Service Cost (millions $)	$424

In Table 16, we show that in the Day Ahead Scenario 4, Smart Power Generation supplies a high percentage of Regulation Up and Load Following Up Ancillary Services. Existing CCGT supplies the major portion of Load Following Down. SPG also has begun to displace hydro in supplying regulation Down requirements.

Table 16: Day-Ahead Scenario 4 Contributions to Ancillary Service

Ancillary Service	Contributed By…								
	Existing CCGT	Existing Gas	Hydro	OTC Combined Cycle	OTC Simple Cycle	SPG Simple Cycle	SPG Combined Cycle	DR	Total
Load Following Up	14%	5%	9%	4%	5%	15%	49%	0%	100%
Load Following Down	68%	8%	8%	7%	1%	0.1%	8%	0%	100%
Regulation Up	1%	0.3%	15%	1%	2%	17%	63%	0%	100%
Regulation Down	10%	12%	33%	8%	2%	0.4%	35%	0%	100%

In Table 17, we summarize the Production Cost impacts of adding Smart Power Generation to the Base Case. While the new scenario produced generation exports, variable costs were still less than the Base Case. Smart Power Generation was cheaper to run. We note a large savings in start/stop costs, as Smart Power Generation supplied a large amount of cost savings. Finally, Day-Ahead Scenario 4 has about 5.1% less energy costs than Base Case Day-Ahead Scenario 1. Depending upon the capacity shortfall backstop, total energy and ancillary service cost savings range from 14% to 5.3% in Day-Ahead Scenario 4 when compared to the Base Case.

Table 17: Day-Ahead Scenario 4 Production Cost Summary

Cost Category	Scenario 4 Costs in Millions $	Percent Change from Base Case
CAISO Variable Generation Cost	$ 4,830	-2.7%
CAISO Start/Stop Cost	$ 93	-48%
CAISO Emission Cost	$ 1,428	-11%
CAISO Total Generation Cost	$ 6,351	-2.4%
Imports from other regions*	$ 319*	-2.4%
Subtotal Energy Supply Cost	$ 6,580	-5.1%
Ancillary Service cost	$ 424	-65%
Total Cost to Serve CAISO Load with DR Backstop	$ 7,004	-14%**
Total Cost to Serve CAISO Load with CT Backstop	$ 7,004	-5.3%**

*Imports from other regions totaled 17,484 GWh, using a weighted average WECC cost of $18.27/MWh; we calculated cost of imports to be about $319 Million.

**There was no Ancillary Service Shortfall in Scenario 4; therefore, we compare the same total cost to serve load number to both DR and CT backstop assumptions, which produces different cost savings when compare to the Base Case.

3.7 Summary of Findings for Day-Ahead Scenarios

Table 18: Production Cost Simulation Summary by Day-Ahead Scenario

Cost Category	Scenario 1 Base Case Costs in Millions $	Scenario 2 No OTC; SPG Simple Cycle Costs in Millions $	Scenario 3 No OTC; SPG Simple & Combined Cycle Costs in Millions $	Scenario 4 All SPG and OTC Costs in Millions $
CAISO Variable Generation Cost	4,963	4,778	4,764	4,831
CAISO Start/Stop Cost	179	99	96	93
CAISO Emission Cost	1,463	1,402	1,401	1,428
CAISO Total Generation Cost	6,605	6,279	6,261	6,351
(+) Added Import Cost	327	380	379	319
Subtotal Energy Supply Cost	6,932	6,659	6,640	6,580
Ancillary Service cost with Demand Response as Backstop	1,201	609	603	424**
Total Cost to Serve CAISO Load with DR Backstop	8,133	7,268	7,243	7,004**
*Ancillary Service Cost with CT backstop	463	447	441	424**
*Total Cost to Serve CAISO Load with CT Backstop	7,395	7,106	7,081	7,004**

*To obtain the Ancillary Service Cost with a CT backstop, we did not re-dispatch results. Instead, we took the hours of ancillary shortfall, number of occurrences and appropriate penalty to back out the cost of Demand Response, then calculated the cost of supplying the shortfall with a generic CT at $97.73/MWh.

**There was no Ancillary Service Shortfall in Scenario 4; therefore, we compare the same total cost to serve load number to both DR and CT backstop assumptions, which produces different cost savings when compare to the Base Case.

For each of the scenarios run, we compare results in Table 18. Note that CAISO variable generation cost is higher in Scenario 4 (SPG and OTC) than Scenario 2 or 3. Since CAISO is exporting to more regions, it is logical to expect a higher production cost and CO2 emission costs being met by CAISO generation. Ancillary Service cost with a generic CT is slightly higher in all scenarios than using a combination of SPG and OTC in Scenario 4.

The large savings in Ancillary Services costs bears further comparison across scenarios. As shown in Table 18, in the Base Case, we observed that Load Following Up, Regulation Up and Spinning Reserves were met by Demand Response on Peak Hour Day, July 22, 2020. Since Demand Response costs are an order of magnitude higher than conventional capacity resources, we estimated costs for this day based upon the average of annual costs.

Despite this cost adjustment, Smart Power Generation capacity in all scenarios showed substantial cost reductions across all scenarios. There was an anomaly in Scenario 3, which showed higher load following down costs ($105 million) with both Smart Power Generation single and combined cycle than with only

Smart Power Generation simple cycle used in Scenario 2 ($93 million). Using Smart Power Generation in Combined cycle mode has (in aggregate) higher minimum operating levels than does the simple cycle configuration. When needing load following down, these aggregate minimum thresholds explain this result. Table 19 summarizes the net savings from Smart Power Generation in each Day Ahead Integrated Forward Market Scenario. We note that the largest savings comes from Ancillary Service when Demand Response is used to backstop ancillary service shortfall.

Table 19: Summary of Production Cost Savings by Scenario

Scenarios Run	Energy Market Costs Savings Millions $ (percent)	DR Backstop Ancillary Service Cost Millions $ (percent)	CT Backstop Ancillary Service Cost Millions $ (percent)
DA Scenario 1 Base Case (No SPG)	N/A	N/A	N/A
DA Scenario 2 (SPG simple cycle; No OTC)	$273 (3.9%)	$592 (49%)	$16 (3.5%)
DA Scenario 3 (SPG simple and combined cycle; No OTC)	$292 (4.2%)	$598 (50%)	$22 (4.8%)
DA Scenario 4 (SPG and OTC)	$352 (5.1%	$777 (65%)	$39 (8.4%)

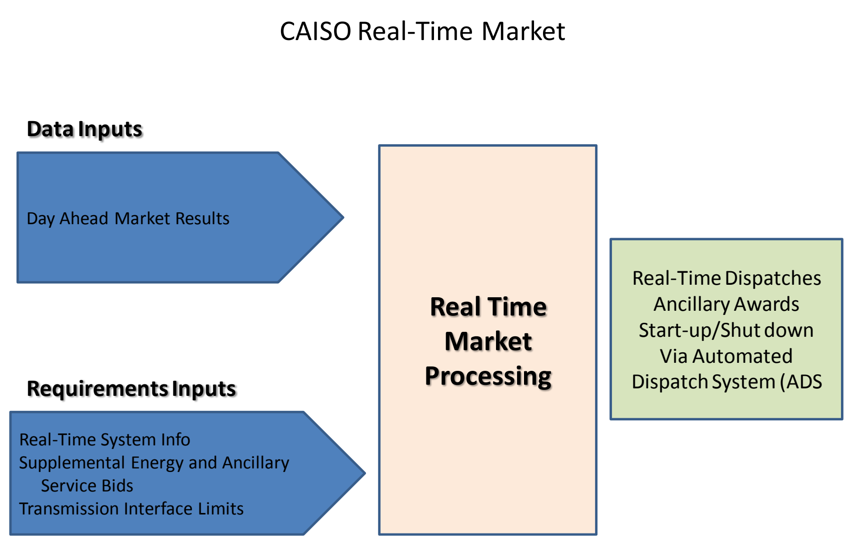
4. Quantifying Smart Power Generation Benefits in Real Time Dispatch

In this section we examine several aspects of five minute real time dispatch. After describing real time markets in CAISO, we compare costs of five minute real time dispatch to Day-Ahead results for similar days. Next, we examine how real time costs vary under different resource mixes. We also examine the impacts of extreme forecast error on real time dispatch. Lastly, we analyze potential savings from different resource mixes under proposed new flexible ramping markets.

4.1 Procuring Resources and Ancillary Services in Real Time Markets

As shown in
Figure 23, CAISO uses the Hour Ahead Schedule Process (HASP) and Real Time 5 minute markets to balance energy requirements, but there are limits to how those resources can be used. Most of the wind and solar resources are non-binding hourly schedules that must be managed in real time; creating a lack of visibility of those resources when load following and regulation are usually scheduled. Aside from the uncertainty associated with these resources, the real time schedules can create a situation where fossil units are "over-committed" to deal with uncertain resources. We did not make adjustments to five minute load following or regulation reserves based upon improved short term forecasts in real time market processing.

Figure 23: CAISO Real Time Market Inputs, Processing and Outputs

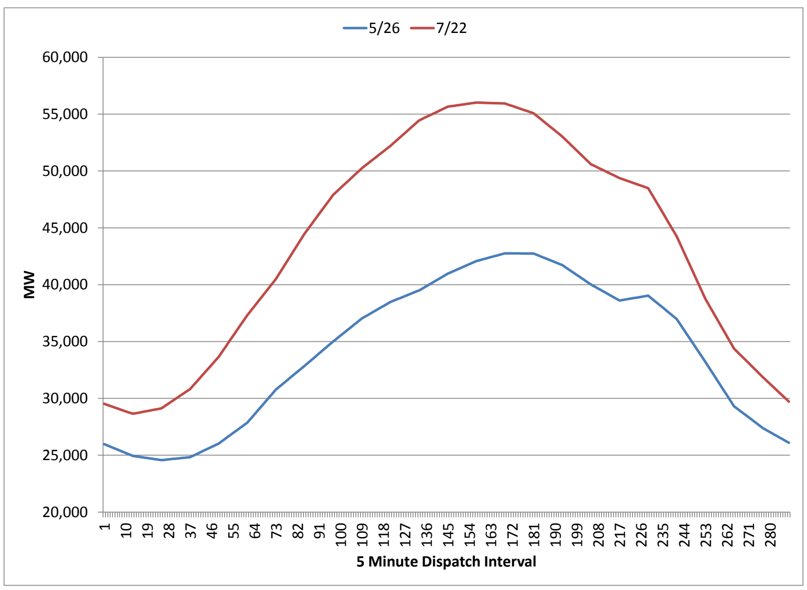


A proposed new market is flexible ramping product, where qualified resources bid in both day-ahead hourly markets and in 5 minute intervals to balance energy markets. Rules for this new product are still being refined, but we know that at least some of the flexible capacity will rely upon real time economic dispatch pricing results, so we also explore market impacts of costs in 5 minute intervals. Rather than replicate day-ahead integrated forward markets, we present only 5 minute ***energy*** market results. Ancillary service costs are not simulated in five minute economic dispatch.

Further, we note that when we sum costs across a 5 minute interval, we must account for costs already occurring in Day Ahead hourly simulations. Therefore, to meet 5 minute dispatch, we subtract any costs to meet those intervals from the simulated day-ahead costs in the hourly interval. In 5 minute real time economic dispatch, any units committed in the hourly dispatch are constrained to operate according to that schedule (and the 5 minute ramps in those schedules). However, because more ramping is expected across 5 minutes, real time costs are expected to be higher to meet those quicker ramps. Some of our real time five minute economic dispatch scenarios are not equivalent to Day-Ahead scenarios, so we compare only real time results to the real time (RT) Base Case.

We simulated peak hour day (7/22) and high load and renewable generation volatility day (5/26) for a variety of scenarios as shown in Figure 24. From the hourly load data, we interpolated 5 minute loads from hourly loads and used in our simulation results.

Figure 24: 5 Minute Loads for 5/26 and 7/22, 2020

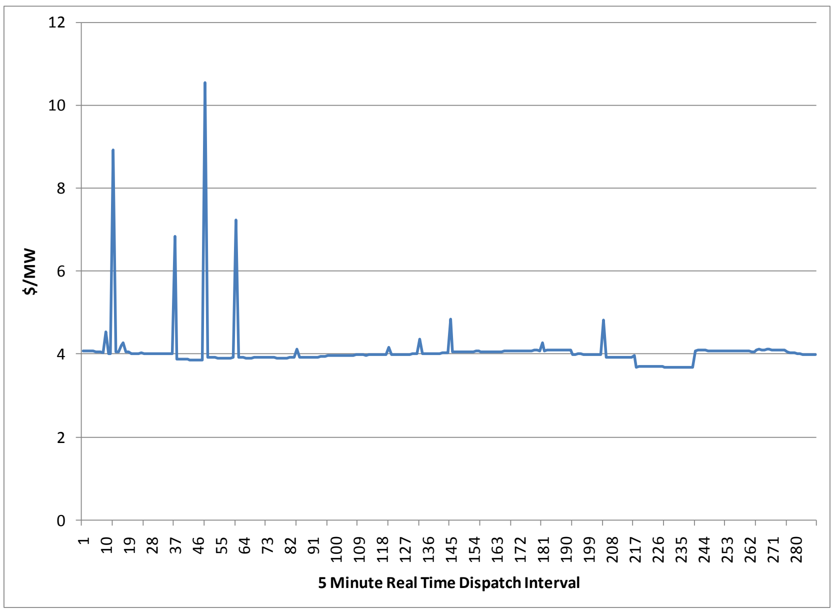


4.2 RT Scenario 1 (Base Case 5 Minute Dispatch)

For RT Scenario 1 we use the same resource mix as deployed in Day-Ahead Scenario 1. In RT Scenario 1 (Base Case with no SPG) we constrain Base Case resources to day ahead hourly unit commitment schedules (from the Day-Ahead Scenario 1 Base Case) and re-dispatch load and resources on a five minute interval to meet loads on 5/26 and 7/22. We then compare results to Day Ahead Scenario 1 (Base Case).

As shown in Figure 25, for the high variability wind/solar day on 5/26, five minute intervals are plotted against $/MW total generation costs (not adjusting for day ahead results). We note that in the five minute intervals, several cost spikes occur as units are started up. Further, there is a slight dip in costs as more combined cycle units are on line and five minute costs begin to decline.

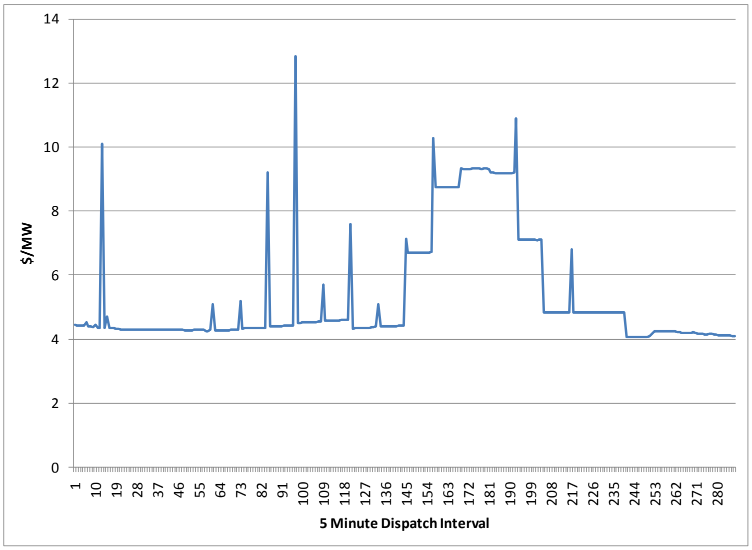
Figure 25: RT Scenario 1(Base Case): 5/26 Five Minute Dispatch



In Figure 26, we display $/MW costs across five minute intervals for 7/22 peak hour day dispatch. As with the 5/26 results, several spikes occur as units are started up between hourly intervals. Further note that costs dip as more combine cycles are brought on line. There is also a step function across peak hour representing price responsive demand response, which is "dispatched" when prices are high enough[33].

[33] Note that these average costs are fairly flat. Recall that we constrained the solution to hourly unit commitment results in the Day-Ahead markets to meet hourly load targets. Spikes occur when we need to ramp or start/stop resources differently in five minute intervals. Further, these results only include energy, not ancillary services.

Figure 26: RT Scenario 1 (Base Case): 7/22 Five Minute Dispatch



In Table 20, we show the net impact of five minute real time economic dispatch in Real Time Scenario 1 (Base Case) compared to Day Ahead Scenario 1 (Base Case) for both 5/26 and 7/22.

Table 20: Day-Ahead Scenario 1 versus Real Time Scenario 1

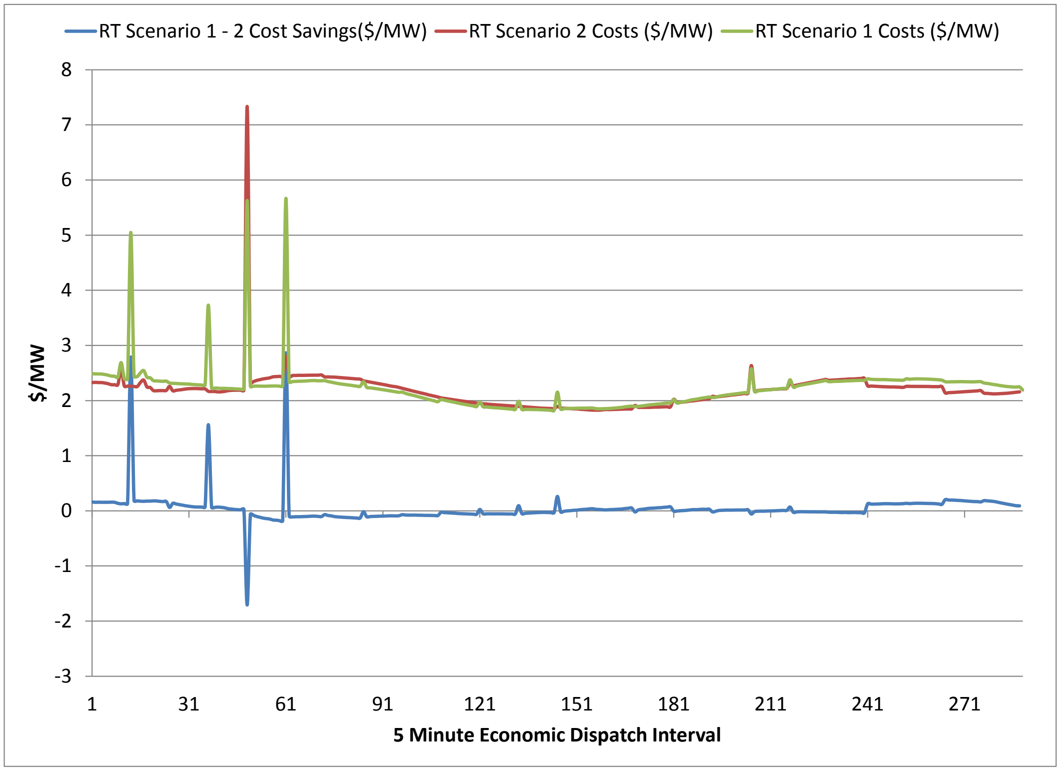
Scenario	Total Cost (millions $)	Added 5 minute cost (millions)	Percent Change
Day Ahead Scenario 1 (Base Case) on 5/26	$17.7	$2.1	12%
Real Time Scenario 1 (Base Case) on 5/26	$19.8		
Day Ahead Scenario 1 (Base Case) on 7/22	$30.3	$5.4	18%
Real Time Scenario 1 (Base Case) on 7/22	$35.7		

We note that five minute dispatch intervals increase costs over day-ahead simulations for both 5/26 and 7/22. On the high renewable generation variability day (5/26) costs to start earlier and ramp quicker leads to $2.1 million or 12% of day-ahead costs. On 7/22 peak hour day, costs to start and ramp earlier was slightly higher ($5.4 million or 18% of day-ahead costs).

4.3 RT Scenario 2 (SPG and OTC 5 Minute Dispatch)

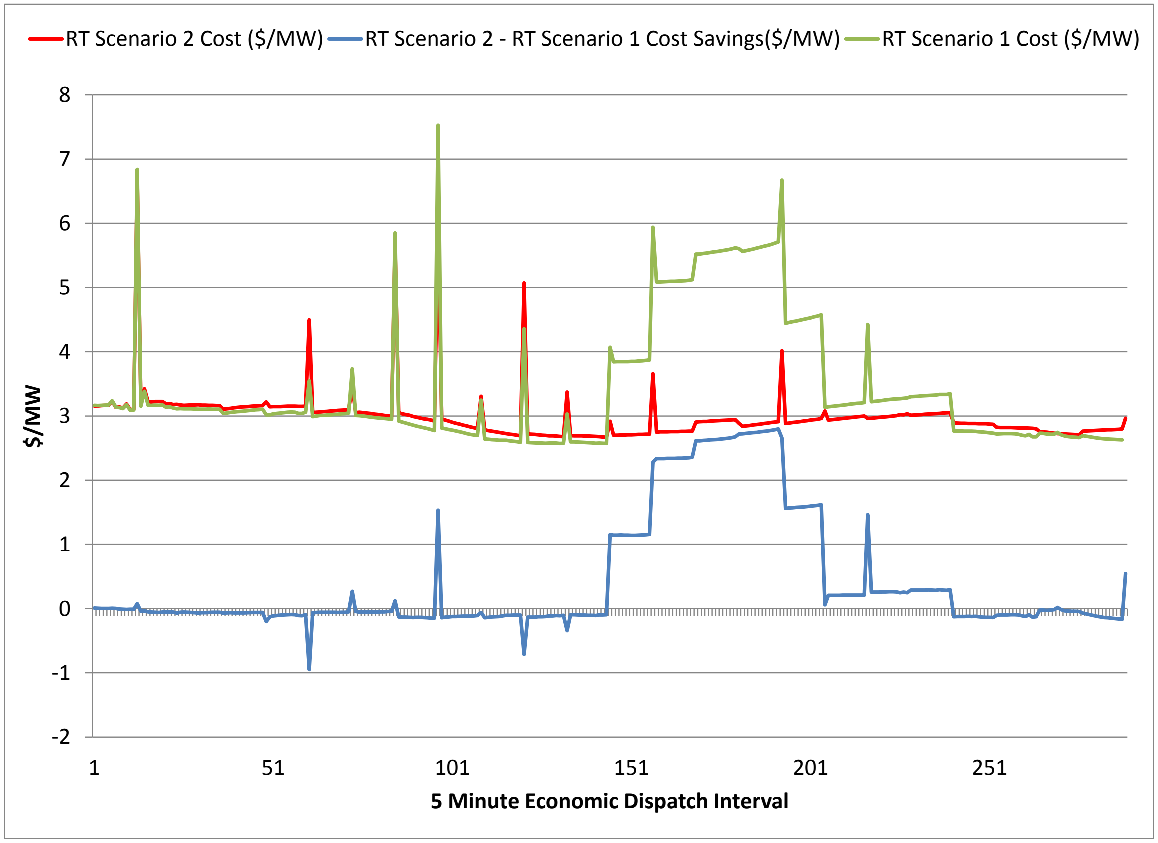
For RT Scenario 2 we use the same resource mix as in Day-Ahead Scenario 4. In RT Scenario 2 (Base + SPG) we add 3.3 GW of SPG combined cycle capacity and 2.2 GW of SPG simple cycle capacity to Base Case resources, constrain results to day ahead hourly unit commitment and re-dispatch load and resources on a five minute interval. We then compare results of Day Ahead Scenario 4 (Base + SPG) to RT Scenario 2 (Base + SPG).

Figure 27: 5/26 RT Scenario 2 versus RT Scenario 1 and Differences



In Figure 27, we show the differences in five minute economic dispatch between RT Scenario 1 (Base Case; No SPG) and Scenario 2 (Base + SPG) for the high renewable generation variability day (5/26). There are a number of smaller start/stop cost savings in Scenario 2 reflecting the lower start/stop and ramping costs of SPG substituted in dispatch. There are 5 minute intervals in which RT Scenario 2 (with added capacity) shows a loss relative to RT Scenario 1 (with less capacity). This is due to the algorithm which first takes a first pass on daily results, recognizing the need to save total costs on the day, will start units earlier in one scenario relative to the other.

Figure 28: 7/22 RT Scenario 2 versus RT Scenario 1 and Differences



In Figure 28, we show the five minute economic dispatch results for peak hour day (7/22) for RT Scenario 2 and RT Scenario 1. In the Base Case (with no SPG), there are a number of price spikes representing intra-hour starts and quicker ramping required. For RT Scenario 2 (with SPG), those spikes are generally less. Further note that price responsive demand is not used in RT Scenario 2, which lowers cost substantially. Once again, there are five minute intervals in which units in Scenario 2 are started earlier than in Scenario 1, showing added costs. The overall daily costs with added capacity are much lower.

Table 21 shows the differences in Real Time Scenario 1 versus Real Time Scenario 2. Adding SPG to the Base Case mix in RT Scenario 2 saves 2.3% or $0.4 million on 5/26 and 38% or $13.6 million on 7/22.

Table 21: RT Scenario 1 versus RT Scenario 2

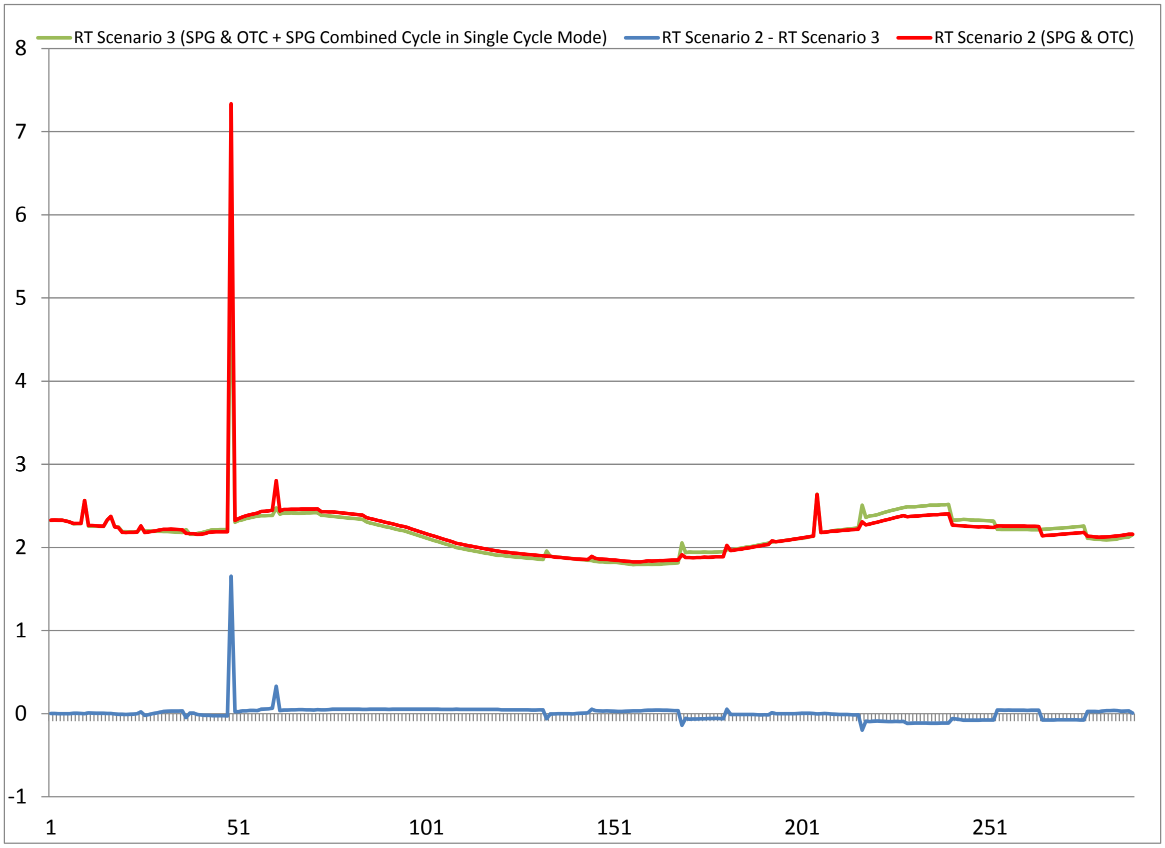
Scenario	Total Cost (millions $)	Adjusted for Exports to WECC[34]	Percent Cost Savings
Real Time Scenario 1 (Base Case) on 5/26	$19.8	$19.8	2.3%
Real Time Scenario 2 (SPG and OTC) on 5/26	$19.6	$19.4	
Real Time Scenario 1 (Base Case) on 7/22	$35.7	$35.7	38%
Real Time Scenario 1 (SPG and OTC) on 7/22	$32.1	$22.1	

4.4 RT Scenario 3 (Added SPG combined cycle in simple cycle mode)

To investigate the benefits of added flexibility in five minute economic dispatch we introduced additional SPG combined cycle capacity operating in simple cycle mode. To RT Scenario 2, we add an additional 3.3 GW of SPG combined cycle capacity operating in simple cycle mode to represent the capability to switch between simple and combined cycle mode. After simulation we compare results in RT Scenario 3 (Base + SPG + SPG combined cycle in simple cycle mode) to RT Scenario 2 (Base + SPG). We expect that some SPG operating in either simple or combined cycle mode will add cost savings over operating SPG in combined cycle mode.

[34] In the RT Scenario 2 on 5/26, 4,239 GWh of generation produced in CAISO was exported to other WECC regions at an average cost of $62.60, reducing costs to meet CAISO load by $264,477 when compared to the Base Case RT Scenario 1. Similarly on 7/22, 55,842 GWh of generation produced in CAISO was exported to other WECC regions at an average cost of $179.85, reducing costs to meet CAISO load by $10,048,771 when compared to the Base Case RT Scenario 1.

Figure 29: RT Scenario 3 versus RT Scenario 2 on 5/26



As shown in Figure 29, the added cost savings of having flexibility with SPG combined cycle operating in either combined or simple cycle mode creates savings in ramping costs on 5/26.

Figure 30: RT Scenario 3 versus RT Scenario 2 on 7/22

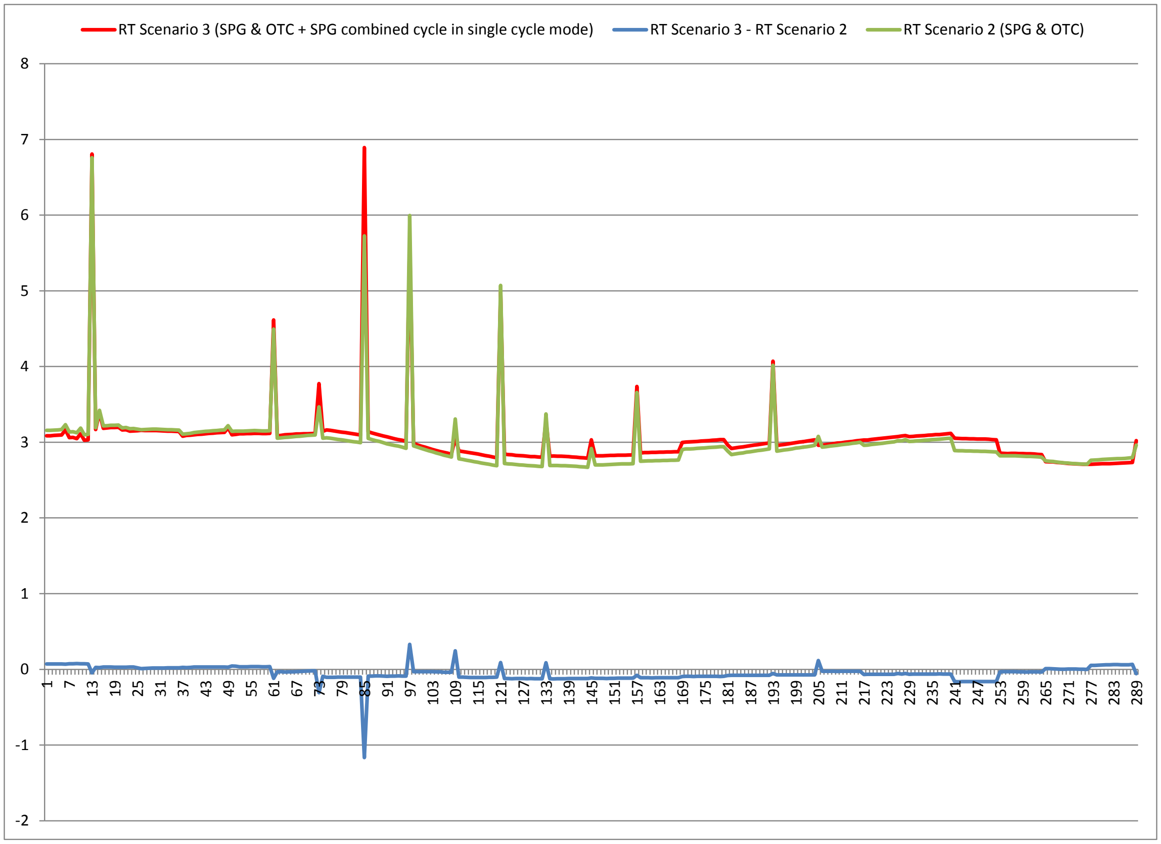


Figure 30 shows that adding flexibility of SPG combined cycles operating in simple cycle mode creates savings for the peak hour day when compared to Scenario 2.

Table 22 compares the added cost savings of additional flexibility in operating SPG in either simple or combined cycle mode. Note that the cost savings is highest in the high renewable and load variability day on 5/26.

Table 22: RT Scenario 3 versus RT Scenario 2 Cost Savings

Scenario	Total Cost (millions $)	Adjusted for Exports to WECC[35]	Percent Change
Real Time Scenario 2 (SPG and OTC) on 5/26	$19.6	$19.3	<0.1%
Real Time Scenario 3 (SPG & OTC with SPG combined cycle in simple cycle mode) on 5/26	$19.5	$19.3	
Real Time Scenario 2 (SPG and OTC) on 7/22	$32.1	$22.1	7%
Real Time Scenario 3 (SPG & OTC with SPG combined cycle in simple cycle mode) on 7/22	$33.5	$19.6	

4.5 RT Scenario 4 (Base Case with Uncertainty in Wind and Solar)

To investigate the impacts of miss-forecasting wind and solar generation in real time, we constructed a worst case forecast for both wind and solar generation and determined the impacts on five minute dispatch.

To construct a forecast, we utilized the 2020 CAISO wind and solar hourly schedules for each region available in the PLEXOS model. We interpolated the hourly regional wind and solar schedules to create a five minute wind and solar schedule for each region. We then forecasted five minute wind schedules based upon a commonly used neural net application[36]. Using the forecasted model error associated with wind, we then calculated the 95% worst case forecast error assuming a normally distributed forecast error. The forecast error can be both higher and lower than the projected 2020 wind schedule. This worst case 2020 5 Minute Wind Forecast schedule was then simulated in PLEXOS to determine costs to meet the forecast error.

For the 2020 Solar Forecast worst case error, we applied a neural net forecast to daylight hours and took a 95% confidence interval around the forecast error. The 95th percentile worst case forecast errors are bunched around daylight hours with both positive and negative differences.

To compare forecast errors, Day-Ahead hour forecast errors reported by CAISO[37]. Lacking data for clearness indexes over which the forecast error is defined, we took a simple average of solar forecast errors across these indexes (5%). For wind forecast errors, we applied an average to seasonal forecast

[35] In the RT Scenario 3 on 5/26, 2,978 GWh of generation produced in CAISO was exported to other WECC regions at an average cost of $62.60, reducing costs to meet CAISO load by $185,826 when compared to the Base Case RT Scenario 1. Similarly on 7/22, 77,454 GWh of generation produced in CAISO was exported to other WECC regions at an average cost of $179.85, reducing costs to meet CAISO load by $13,937,822 when compared to the Base Case RT Scenario 1.

[36] Time Series Prediction and Neural Networks, R.J.Frank, N.Davey, S.P.Hunt, Department of Computer Science, University of Hertfordshire, Hatfield, UK.

[37] See Track 1 Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator Corporation (Corrected), R.10-05-006. Slides 65-70.

errors and obtained (4.5%). Noting that these forecast errors are average, we then computed a worst case forecast error at 95% confidence interval and multiplied each forecast error by a factor of 1.645 (8.2% for solar and 7.4% for wind).[38] We then interpolated hourly schedules across five minute intervals to produce a five minute schedule for wind and solar on 5/26 and 7/22 in 2020. Applying the worst case forecast error to both wind and solar, we then created a new wind and solar schedule and then simulated five minute real time economic dispatch and analyzed results. Table 23 compares average worst case forecast errors.

Table 23: Comparison of Worst Case Forecast Error

Renewable Generation Type	**Reported Day-Ahead forecast error** proxy worst case **translated to 5 minute real time error**	Forecast error through neural net forecast used in study
Solar/PV generation	8.2%	11%
Wind generation	7.4%	9%

We first simulated worst case renewable generation schedule forecast in the Base Case and compare results as shown in
Table 24. We found that worst case forecasts relying on Base Case resources increased costs to meet the forecast by 7.4% or $1.2 million.

Table 24: RT Scenario 4 versus RT Scenario 1

Scenario	Total Cost (millions $)	Adjusted for WECC exports and extra wind[39]	Percent Change
Real Time Scenario 1 (Base Case) on 5/26	$19.8	$19.8	<0.1%
Real Time Scenario 4 (Base Case; Worst Renewable Forecast) on 5/26	$19.8	$19.8	

4.6 RT Scenario 5: (SPG and Base Case with Uncertainty in Wind and Solar)

To analyze the impact of SPG on worst case uncertainty of wind and solar/PV generation forecasts, we simulated worst case renewable generation schedule forecast adding SPG simple and combined cycle

[38] Assuming a normal distribution of forecast errors and applying 1.645 from Ostle and Mensing, Statistics and Research, Iowa State University Press, page 535.

[39] In the RT Scenario 4 on 5/26, 3,727 GWh of generation produced in CAISO was exported to other WECC regions at an average cost of $62.60, reducing costs to meet CAISO load by $232,586 when compared to the Base Case RT Scenario 1.

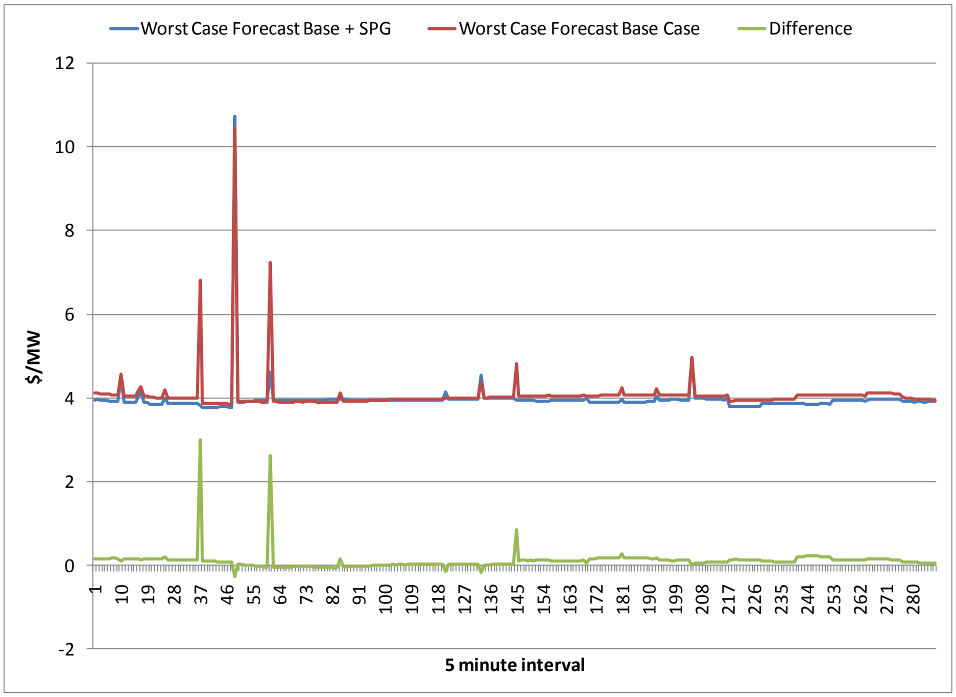
generation to Base Case resources and simulated results in five minute economic dispatch. Results are compared in Table 25.

Table 25: RT Scenario 5 versus RT Scenario 4

Scenario	Total Cost (millions $)	Adjusted for WECC exports & extra wind	Percent Change
Real Time Scenario 4 (Base Case; Worst Renewable Forecast) on 5/26	$19.8	19.8	1.1%
Real Time Scenario 5 (Base Case + SPG; Worst Renewable Forecast) on 5/26	$19.8	19.6	

SPG reduced costs by $0.2 million or 1.1%. Most of the cost reductions came from cheaper start/stop and ramping costs as shown in Figure 31.

Figure 31: RT Scenario 4 versus RT Scenario 5 on 5/26



4.7 Smart Power Generation and Flexible Ramping (or similar) Ancillary Service(s)

CAISO has proposed to implement a flexible ramping constraint to address reliability and operational issues observed in the CAISO's operation of the grid[40]. CAISO has observed that there is a lack of sufficient ramping capability and flexibility to handle imbalances in 5 minute dispatch intervals, manifested in procuring an inefficient level of high ramping frequency resources in regulation markets.

Flexible ramping products have two major goals. One is to improve the ISO's dispatch flexibility, and the other is to do so in a cost effective way. Flexible ramping products are 5-minute flexible capacities dispatchable by CAISO, which are able to deal with the energy imbalances in Real Time 5 minute Dispatch intervals. The flexible ramping consists of separate products in the upward and downward directions as the imbalances may be positive and negative. The imbalances can result from variability or uncertainties.

[40] Flexible Ramping Products, Draft Final Proposal; by Lin Xu, Ph.D. Market Analysis and Development and Donald Tretheway, Market and Infrastructure Policy, April 9, 2012

While it is clear that some flexible ramping products will be procured in the Day Ahead Hourly Integrated Forward Market, some of the settlement will occur based upon five minute real time prices. The 5 minute real-time dispatch interval matches real time ramping requirements under Flexible Ramping rules (load following up and down).

Based upon the scenarios simulated in this section for select days, there is substantial 5 minute real time cost savings summarized in Table 26. We estimate that flexible ramping product cost savings in real time could be as high at $13.6 million on peak hour day to $0.4 million on high load, wind and solar volatility days when compared the RT Scenario 1 Base Case.

Table 26: Comparison of Flexible Ramping Cost Savings Potential

Scenario	High Load, Wind, Solar Volatility Day (5/26)	Peak Hour Day (7/22)
Incremental Savings in Millions of Dollars ($)/ percent savings (%)		
RT Scenario 1 (Base Case) versus RT Scenario 2 (SPG and OTC) incremental savings	$0.4/2.3%	$13.6/38%

4.8 Summary of Real Time Results

Trends in RTO markets will create a lot of uncertainty in how resources are used, requiring more reserves and balancing impacting real time five minute economic dispatch. We examined how some of this uncertainty unfolds with both Base Case resources and with Smart Power Generation. We found that Smart Power Generation can reduce the cost of producing energy in several ways. By ramping and starting/stopping quickly, Smart Power Generation can improve costs of other resources in real time five minute economic dispatch. We investigated five different real time scenarios and we summarize these results in Table 27.

Table 27: RT Scenario Savings Summary

Scenario	High Load, Wind, Solar Volatility Day (5/26)	Peak Hour Day (7/22)
Incremental Savings in Millions of Dollars ($)/ percent savings (%)		
RT Scenario 1 (Base Case) versus RT Scenario 2 (Base + SPG) incremental savings	$0.4/2.3%	$13.6/38%
RT Scenario 2 (Base + SPG) versus RT Scenario 3 (Base + SPG + SPG combined cycle in simple cycle mode) incremental savings	$<0.1/<0.1%	$2.5/7%
RT Scenario 1 (Base Case) versus RT Scenario 3 (Base Case -- Worst Case Forecast) incremental savings	$<0.1/<0.1%	N/A
RT Scenario 3 (Base Case -- Worst Case Forecast) versus RT Scenario 4 (SPG and OTC -- Worst Case Forecast) incremental savings	$0.2/1.1%	

In RT Scenario 1, we establish a real time Base Case against which to compare other real time scenarios. In the Base Case we constrain resources to meet Base Case unit commitment in the day-ahead solution and then dispatch all resources to meet a five minute load instead of an hourly load. We focused only upon two days: (a) five minute economic dispatch on 7/22 peak hour day, and, (b) five minute economic dispatch on 5/26 high load, wind and solar volatility day. Five minute real time dispatch created higher costs than day-ahead unit commitment results because of earlier ramping and start/stop costs in the real time market.

In RT Scenario 2 (Base + SPG), we added 2.2 GW of SPG simple and 3.3 GW of SPG combined cycle capacity to Base Case resources and re-dispatched across five minute real time intervals. Relative to RT Scenario 1 (Base Case) we found $0.4 million in cost savings (2.3%) on 5/26 and $13.6 million in cost savings (38%) on 7/22. These cost savings are due to cheaper starts/stops and ramping costs from SPG. These savings provide a range of estimates for potential cost savings of SPG in the new flexible ramping market.

In RT Scenario 3 (Base + SPG + SPG combined cycle in simple cycle operating mode), we added 3.3 GW of SPG combined cycle capacity to Scenario 2 and re-dispatched across five minute real time intervals. This scenario examines additional cost savings from the flexibility of running SPG combined cycle in either combined cycle mode or in simple cycle mode. We found slight cost savings less than $0.1 million (<0.1%) on 5/26 high load, solar and wind variability day; and $2.5 million (7%) cost savings on peak hour day of 7/22.

In RT Scenario 4 (Base Case with 95% worst case renewable generation forecast) and RT Scenario 5 (Base + SPG with 95% worst case renewable generation forecast), we create a 95th percentile worst case wind and solar forecast. We found that wind forecasts created a slight incremental cost (<0.1%) relative to RT Scenario 1 (Base Case). However, adding 5.5 GW of SPG simple and combined cycle capacity creates cost savings of $0.2 million (1.1%) over Base Case resources.

5. Smart Power Generation and Resource Adequacy

To measure resource adequacy with diverse resources, it is necessary to incorporate measures of supply disruption/uncertainties using different resource mixes for each scenario and for each supply resource. For example, we use substantially more demand response to meet shortages in regulation, load following and spinning in Day Ahead Scenario 1 (Base Case). In Day-Ahead Scenario 2 (Base + SPG simple cycle; No OTC), we remove new or re-powered OTC re-powered generation and replace them with Smart Power Generation simple cycle units, finding that Smart Power Generation units reduce the shortfall costs of ancillary services.

Any time there is a substantial resource mix change, it is prudent to calculate long term resource adequacy. Because there is more variability in supply in 2020, we need to expand traditional measures of resource adequacy which focus only on forced outage rates to include other uncertainties such as forecast error, startup failure and ramp rate variability. Forecast error is defined as the difference between planned and forecasted generation[41]. From the study we calculate an average error of 2% distributed normally. Starting error is a five year average ratio of number of times that units did not start divided by the total start attempts from NERC GADS data[42]. Forced outage rates were used from NERC data by unit type. Ramp rate variability was calculated from prior work on distributed energy resource simulation for CAISO[43]. We also used forced outage and startup failure rates from industry sources.[44] For Demand Response, we estimated uncertainties from industry sources.[45]

Much like Loss of Load Equivalence, we examine a threshold of adding capacity to meet the one day in ten years to meet those supply disruptions/uncertainties. We then calculate Combustion Turbine capacity required versus Smart Power Generation (simple cycle and combined cycle) capacity required. The results are shown in Figure 32.

[41] Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources, June 2012

[42] www.NERC.com

[43] Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources, June 2012

[44] Technology Characterization: Reciprocating Engines, ICF, December 2008.

[45] Johanna Mathieu, Duncan Callaway, Sila Kiliccote, Environmental Energy Technologies Division, Examining Uncertainty in Demand Response Baseline Models and Variability in Automated Responses to Dynamic Pricing, Lawrence Berkeley National Laboratory, August 2011.

Figure 32: Deliverability @ Risk: Scenario 1 Base Case versus Scenario 4 All Generators

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Resource	**Scenario 1: Base Case (1)**	**Scenario 2: Replace OTC with Single Cycle Smart Power Generation (1)**	**Scenario 3: Replace OTC with Single & Combined Cycle Smart Power Generation (1)**	**Scenario 4: All Generation**	**Uncertainty Estimate**			
	Peak Hour Resource	**Peak Hour Resource**	**Peak Hour Resource**	**Peak Hour Resource**	**Forced outage**	**forecast error**	**startup failure**	**ramp rate variability**
	MW	MW	MW	MW	%	%	%	%
Nuclear	4,486	4,486	4,486	4,486	2%		2%	
Other	4,575	3,556	3,556	2,787			5%	1%
Demand Response	-	-	-	-	20%	5%	5%	10%
Solar	8,776	8,776	8,776	8,776	10%	5%	5%	10%
Wind	1,147	1,147	1,147	1,147	10%	5%	5%	10%
Hydro	7,623	8,311	8,306	8,106	6%			
Gas	14,764	16,636	16,637	15,795	12%		2%	
New OTC Gens	4,157	-	-	4,884	7%		1%	
SPG combined cycle)	-	-	2,174	1,875	6%		1%	
SPG single cycle	-	1,593	319	599	6%		1%	
Import(+)/Export(-)	10,474	11,497	10,601	7,562	2%			
Smart Power Generation (single	**n/a**	**9,206**	**9,148**	**8,683**				
Smart Power Generation (combined	**n/a**	**n/a**	**9,148**	**8,683**				
CT Capacity to Meet 1	**9,576**	**n/a**	**n/a**	**8,794**	**111**			

(1) In the Base Case 5.6 GW of repowered OTC generation was used; in Scenario 2, we replaced that generation with Smart Power Generation.
[5] For Gas and New OTC Generation, we used NERC GADS FOR rates. For Demand Response, we used estimates from DNV KEMA's DER estimates. For
[6] Forecast Error measures difference between monitored variable resource and naïve forecast from DNV KEMA's DER estimate.
[7] For Gas, OTC and Wartsila, we used NERC GADS data. For Demand Response, we used DNV KEMA's DER study.
[8] For Demand Response Ramp Rate Variability we used DNV KEMA's DER study.

As shown in Figure 32, Demand Response has more uncertainty than most of the fossil generation used in its place. By reducing the use of demand response, resource adequacy in our scenarios improves. Further, because Smart Power Generation has less uncertainty than the displaced new or OTC re-powered generation, less capacity is required to meet the 1 day in 10 years resource adequacy construct.

Relative to the Base Case without Smart Power Generation, Scenario 2 shows that less Smart Power Generation Capacity is required to meet a one day in ten years resource adequacy criteria (9576 MW versus 9206 MW).

Relative to the Base Case without Smart Power Generation, Scenario 3 shows that less 50% mix of single and combined cycle Smart Power Generation Capacity is required to meet a one day in ten years resource adequacy criteria (9576 MW versus 9148 MW).

Relative to the Base Case without Smart Power Generation, Scenario 4 shows that less 50% mix of single and combined cycle Smart Power Generation Capacity and new or OTC re-powered generation is required to meet a one day in ten years resource adequacy criteria (9576 MW versus 8683 or 8794 MW).

6. Conclusions

- Like many North American RTOs, CAISO faces a number of future challenges to meet wholesale energy and ancillary service requirements. In this paper, we simulated 2020 wholesale market conditions and operational constraints likely to be faced by CAISO and other RTOs facing similar challenges such as heavy penetration of renewable generation and other variable resources. These simulations are used to analyze impacts and plan for future trends.

- In Day-Ahead Integrated Forward Markets, we found that high load growth and high levels of renewable generation and other distributed generation lead to shortfalls in meeting projected ancillary service requirements for three of the four scenarios investigated.

  — We found that either Demand Response or Generic CT backstops to meet projected ancillary service shortfalls are more expensive alternatives than using Smart Power Generation in resource portfolios.

  — In 2020, we found energy cost savings ranging from 3.9% to 5.1% ($273 million to $352 million, respectively) by introducing Smart Power Generation into the mix of resources to meet energy requirements. Those cost savings come from utilizing relatively more efficient Smart Power Generation simple cycle capacity in place of existing CCGT, existing gas and even new or re-powered OTC generation.

  — In 2020, we found that costs to provide ancillary services can be reduced from 3.5% to 8.4% ($16 million to $39 million, respectively) by introducing Smart Power Generation into the mix of resources instead of using a generic CT backstop. We found even greater ancillary service cost savings when Smart Power Generation replaces Demand Response as a backstop.

  — Smart Power Generation provides Ancillary Services because it delivers fast, low cost ramping and low start costs. Smart Power Generation allows other units (like combined cycles) to operate in a more uniform fashion and minimize expensive start/stop cycles when other units are used to provide Ancillary Services. Depending on the SPG scenario and the choice of backstop in case of shortfalls, savings in total delivered costs range between 4% and 15%. These cost savings occur only with respect to changing 5.5 GW of at 78 GW (about 7%) of the CAISO resource portfolio.

- We simulated five minute real time economic dispatch to determine (i) how Smart Power Generation added to the resource mix may save incremental real time costs; (ii) determine the impact of worst case renewable generation forecast; and (iii) the range of potential cost savings provided by Smart Power Generation in the new flexible ramping product.

- Smart Power Generation lowers Real Time dispatch costs. This is due to lower start/stop costs and more efficient simple cycle machines in dispatch. We found that introduce SPG simple and combined cycle capacity into Base Case resource mixes will lower dispatch costs on peak day (7/22) by $13.6 million (38%) and on a highly volatile wind, solar and load day (5/26) by $0.4 million (2.3%).

- Introducing flexibility of SPG combined cycle in simple or combined cycle mode provides additional cost savings. On peak hour day (7/22), we found cost savings of $2.5 million (7%) when compared to RT Scenario 2 (Base + SPG). On the high wind, solar and load volatility day (5/26), we found minor cost savings (<0.1%) when compared to RT Scenario 2 (Base + SPG).

- Renewable generation is subject to forecast errors. By examining worst case forecast error impacts on five minute real time economic dispatch, we find that five minute real time economic dispatch cost decreases occurs with Smart Power Generation configurations. For the high volatility day, SPG capacity can reduce costs by as much as $0.2 million (1.1%).

- Under flexible ramping rules, a portion of five minute flexible ramping requirements will be managed in real time economic dispatch. While the portion of flexible ramping settlements in five minute economic dispatch is still uncertain, the range of cost savings can be as high as 38%.

- CAISO is considering several long term planning alternatives to increase Resource Adequacy. A traditional measure of resource adequacy is to build enough capacity to meet a loss of load criteria of less than or equal to one day in ten years, assuming uncertainty in forced or unplanned outage of generation units. Expanding uncertainty to include start-up failures, miss-forecasted resources, and ramping uncertainty in addition to forced outages, we calculated the probabilities of these uncertainties based upon publicly available NERC data or industry resources. We then measured Deliverability@Risk which is the additional capacity required to be less than or equal to one day in ten years deliverability requirement. Smart Power Generation requires 364 MW less capacity than combustion turbines because of lower forced outage probability, higher start-up probability and more certain ramping.