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California Independent
System Operator

California ISO

2005 Peak Day Summer Simulation Report

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Executive Summary

On Tuesday May 3, 2005, the California ISO and its Scheduling Coordinators initiated a 2005 summer peak day simulation in an attempt to gain additional operational insight into the quantity and deliverability of supply arranged to meet the expected peak load conditions this summer. This was essentially a test of the CAISO Control Area's ability, using both transmission and generation, to meet this summer's peak hourly demands under varying temperature scenarios. This was a collaborative effort, the CAISO working with its market participants, to better prepare for what will most likely be a challenging summer.

The initial analysis of the results of the simulation corroborates many of the findings made in the CAISO's 2005 Summer Assessment.

In summary sufficient supply is available and secured[1] to meet the expected peak demand (i.e., at "normal" load levels). Additional supply that was not scheduled or bid in the simulation may need to be secured to meet the necessary operating reserve margins to avoid a system emergency during a peak load condition, combined with a significant loss of transmission or generation. Congestion (the overloading of transmission line paths) did not appear to be a significant factor limiting the ability to deliver supply. However, if key transmission or generation outages were to occur, operating reserve margins could be depleted to critical levels that may require load curtailment under either scenario examined in this simulation.

The cooperation from participants was excellent. The CAISO greatly appreciates the total support from 39 participants that included load serving entities, suppliers and marketers. The level of participation included participation from entities that represent approximately 98% of the forecasted load.

The CAISO has reviewed these results with the participants of the simulation. During the review some parties indicated that the scheduled supply did not necessarily represent actual contractual commitments. Based on follow-up discussions it is estimated that at least 2000 MW of scheduled supply may not be secured with actual contracts, as yet. However, determining exactly how much of the scheduled supply is not supported by actual contracts is difficult to determine since the source for some of these power sale arrangements will not be known until the contracts are consummated sometime between now and the actual trade day.

As explained in the body of this report, other significant sources of uncertainty include the level of generation and transmission outages, the impacts of congestion, and the availability of capacity that is often available but was not scheduled or bid in the simulation. These limitations should be explicitly recognized in any policy decision that relies on the result of the peak day simulation and this report.

[1] The CAISO provided instruction for the simulation that requested when scheduling for the simulation, schedules should reflect contractual arrangements.

Overview of Results

On March 31, 2005, the CAISO completed its 2005 Summer Assessment. Although the 2005 Summer Assessment concluded that there is enough generation capacity and underlying transmission capacity available to meet the expected 2005 peak load, there are concerns regarding the ability to serve the load in Southern California for both normal and adverse conditions, and concerns for serving the entire control area if loads are high.

As the CAISO continues to prepare for this summer, the CAISO can be better prepared if it also develops an understanding of what might happen as loads and resources are actually scheduled. Load Serving Entities (LSEs) have stated that they have secured sufficient capacity to meet each LSE's expected 2005 peak load plus an additional reserve margin, but details have not been available to indicate the physical source of the supply and thereby permit testing of its deliverability. With this in mind, the CAISO proposed a Summer Peak Load Simulation. The purposes of this simulation were:

(1) To gain a better understanding of the arrangements that LSEs have made with generation resources, importers, and marketers of energy, to meet two load scenarios (a forecasted "1-in-2 year" and a "1-in-10 year" forecasted peak load condition) plus necessary operating and planning reserves,[2] and

(2) To use the simulation data to provide insight as whether the resources and imports that are intended to meet the peak load conditions will fit on the available transmission system.

At the outset, the CAISO understood that performing this simulation would be a complex task and the level of its success would be determined by numerous factors. The Simulation was conducted in the hopes that the CAISO would gain a better understanding of how loads are planning to be matched against resources, identify units that are more constrained than had been anticipated, or determine that there is an unusually large number of imports planned over one import path. However, the CAISO also recognized early on that the simulation might not provide as much detail as hoped for, because the engineered simulation model might not solve, there could be problems with submitted supply and demand data, or the results might not synch up with actual operating conditions. However, in either regard, the CAISO, through working with market participants, would learn from the simulation and be able to apply this experience in future summer preparedness efforts. Although questions have arisen during the study that the CAISO will still be resolving, this simulation has provided a significant amount of useful information as the CAISO prepares for this summer. This accomplishment is largely due to the cooperation of market participants. The CAISO greatly appreciates the cooperation that market participants have provided through their participation.

On Tuesday, May 3, 2005, the CAISO received scheduling and bidding data from its Scheduling Coordinators (SCs), representing market participants to conduct a 2005 Peak Day Simulation. At the May 6, 2005, CAISO Board of Governors meeting, the CAISO reported the first results from the submitted data. When the system closed to input, 39 SCs had submitted schedules per the CAISO's instructions. The first quick review confirmed that most of the required SCs had participated, and scheduled loads

[2] The "1-in-2 year" forecast represents the level that is expected to be exceeded in one out of every two years, i.e., has a 50% chance of being exceeded. The "1-in-10 year" forecast represents the level that would be exceed once per 10 years, i.e., has a 10% chance of being exceeded.

were close to the anticipated load schedules. After conducting more detailed review and analysis, at this time the CAISO can report what has been determined so far.

On May 31, 2005, the CAISO shared its results and findings with Participants of the simulation. As there were differences between forecasted load and scheduled load as well as capacity found not to be scheduled or bid, the CAISO undertook some a set of follow-up discussion in order to better analyze the differences. Appendix A documents that follow-up analysis.

In aggregate, the participants' total scheduled supply fell short of demonstrating a 115% level of resource adequacy. From the initial submissions of the 2005 Peak Load Simulation, 92.5% of the expected "1-in-2" peak load and 92% of the expected "1-in-10" peak load day was scheduled by LSEs. Additional "load" was also submitted in the form of load schedules, for which no actual load responsibility exists, by generation owners who scheduled Reliability Must Run (RMR) contracts as instructed by the CAISO and did not have trades with other SCs to deliver their energy to actual LSEs.[3] Thus, the supply (generation plus net imports) that was scheduled amounts to 95% of forecasted load in the "1-in-2" scenario and 94% in the "1-in-10" scenario. In the resulting load schedules, approximately 3380 MW of the expected "1-in-2" load, excluding 1300 MW of forecasted transmission losses, was not scheduled and 4080 MW of the "1-in-10" expected load was not scheduled.[4] Table 1 compares the CAISO's load forecast to the submitted schedules, and adds detail regarding additional capacity requirements that constitute the reliable operation of the CAISO's system.

[3] Under today's market structure, SCs must schedule a balanced portfolio with matching supply and demand, so these generation owners needed to submit loads to balance their portfolios even though no actual load responsibility exists.

[4] The CAISO will be exploring further the reasons why some of the forecasted load was not scheduled. Three SCs who served load at the time of the 2004 summer peak did not submit schedules in this simulation. Some realignment of which LSE serves which load has occurred during the past year, as a large transmission owner previously scheduled load for other SCs who are now scheduling their own loads, and as the Western Area Power Administration (WAPA) moved from the CAISO Control Area to the Sacramento Municipal Utilities District (SMUD) Control Area. In addition, some Direct Access load has moved between LSEs. In some instances, the new LSEs therefore scheduled more load than the CAISO assigned based on settlement data for the 2004 system peak (since they now schedule load that other SCs scheduled during 2004), but in other instances this did not occur.

Table 1: Load Responsibility

	Forecasted Load (MW)		Scheduled Load (MW)[5]	
	1-in-2	**1-in-10**	**1-in-2**	**1-in-10**
PG&E Area	20,801	22,600	19,129	20,632
SCE Area	20,923	22,733	19,537	20,983
SDG&E Area	3,644	3,959	3,321	3,593
Subtotal: Load	45,368	49,292	41,987	45,208
Scheduled load as % of forecast			92.5%	91.7%
Losses	1,300	1,300		
Subtotal: Load + Losses	46,668	50,592		
New Demand Response Participation	-130	-130		
Total Load + Losses (After new Demand Response)	46,538	50,462		
Ancillary Service Requirement	3,150	3,386		
Total Load + Losses + AS Reqt.	49,688	53,848		
Total Load + Losses + 15% Planning Reserve	53,519	58,031		

In addition to load schedules, the simulation includes the submission of supply schedules to match the load schedules, and supplemental adjustment bids to provide ancillary services (i.e., capacity reserves) and additional energy. Enough additional energy bids are available in the simulation to serve the under-scheduled load and losses, if reserve requirements and limits on resource availability are not considered.[6] Table 2 summarizes the supply schedules and bids that SCs submitted for the simulation.

[5] The amounts of scheduled load shown in this table exclude approximately 1250 MW load that were submitted by generation owners to achieve balanced portfolios including RMR generation that was scheduled as instructed by the CAISO.

[6] In processing the SCs' schedule and bid submissions, the CAISO has completed the entry of bids in most instances where the SCs indicated an intent to bid, even if their entries were incomplete. In cases where SCs submitted bids for ancillary services but did not supply a corresponding energy bid curve, the CAISO extended their submitted energy bid curves for the capacity that was submitted as ancillary services. (The bid price for these bids is $500/MW, which was applied to all ancillary service bids so they would be dispatched only after other feasible economic energy bids had been dispatched.) In cases where SCs indicated via electronic mail that they would have submitted trades with SCs that did not participate in the simulation, the CAISO added import bids to represent the missing trades. However, the CAISO did not enter a bid for which one LSE asserted that its counter-party would be submitting a 70 MW generation bid, but for which the counter-party participated in the simulation and did not submit the corresponding bid. Also, the CAISO did not add bids for 1500 MW of energy that one LSE stated it would have obtained from suppliers who did not participate in the simulation, and which the LSE described as "schedule to be sourced from market" – there is no assurance in these instances that the suppliers have new supplies from outside the CAISO's own real-time market.

Table 2: Supply Schedules and Bids

	Supply Schedules and Bids (MW)	
	1-in-2	**1-in-10**
Generation: Schedules	35,193	37,046
Generation: Ancillary Services[7]	2,491	1,976
Generation: Supplemental Energy	2,141	1,398
Generation: Total	39,825	40,420
Net Import: Schedules	8,069	9,385
Net Import: Ancillary Services	0	0
Net Import: Supplemental Energy	1,078	1,078
Net Import: Total	9,147	10,463
Total Scheduled Supply	43,262	46,431
Total AS + Supplemental Energy	5,710	4,452
Total Scheduled + Bid Supply	48,972	50,883

Although enough energy schedules and bids are available in the simulation to serve the forecasted load and losses, if reserve requirements and limits on resource availability are not considered, the total quantity of submitted energy bids (including supplemental adjustment energy bids) is insufficient to fully meet the load forecast plus additional operating reserve requirements of approximately 6%. The CAISO will be further reviewing why this shortfall occurs, since about 5,510 MW (3795 MW North of Path 26 and 1715 MW South of Path 26) of generation had no schedules or bids submitted into the simulation, and additional generators had only a portion of their capacity submitted. An additional 2389 MW in the 1-in-2 scenario and 2169 in the 1-in-10 scenario of capacity was not bid from resources that scheduled some portion of their generation. Table 3 compares the submitted supply schedules and bids to the CAISO load forecast and additional capacity requirements, to show the extent to which the submitted supply meets the required capacity.

[7] Although the amount of ancillary service bids appears to be less than the requirement, some SCs offered to submit their bids as additional ancillary service capacity if needed. The CAISO's scheduling instructions stated that LSEs do not need to self-provide their ancillary service obligations, and can purchase from the market.

Table 3: Comparison of Supply vs. Load Responsibility

	Supply vs. Demand (MW)	
	1-in-2	**1-in-10**
Total Load + Losses (after new Demand Response)	46,538	50,462
Total Scheduled Supply	43,262	46,431
Scheduled Supply as % of Load (including losses, after new Demand Response)	95.4%	94.2%
Total Load + Losses + AS Reqt.	49,688	53,848
Total Load + Losses + 15% Planning Reserve	53,519	58,031
Total Scheduled + Bid Supply	48,972	50,883
Reserve Margin: Total Supply as % of Load[8] (including losses, after new Demand Response)	5.2%	0.8%
Total Supply Minus Load, Losses, and Ancillary Services[9]	-714	-2,965
Total Supply Exceeding 15% Planning Reserve[8]	-4,547	-7,148

The above comparisons can also be examined by industry sector (investor-owned utilities, municipal and governmental entities, and other entities). The following comparisons in Tables 4 and 5 will be affected by information that the CAISO is still gathering regarding shifts of load between industry sectors, as (1) some SCs previously used scheduling services provided by the utilities but are now scheduling their own loads or using scheduling services provided by other SCs, and (2) some loads have moved between suppliers. The comparison presented here uses the load responsibility that was originally stated in the CAISO's scheduling instructions, pending the completion of revised data on current load responsibilities. Also, Tables 4 and 5 are a simple comparison between forecasted load and quantities of supply scheduled and bid by the same SC that serves the load. In addition to direct scheduling of supplies, LSEs serve their load via bilateral contracts with other suppliers, which are scheduled with the CAISO as trades among SCs[10].

[8] Reserve margins less then 7% may require declaration of a stage 1 emergency, less then 5% may require declaration of a stage 2 emergency and less then 1.5% may require declaration of a stage 3 emergency.

[9] A portion of the reserve margin shortfalls observed might be available from the 5510 MW of resources that have neither scheduled nor bid into the simulation. However, this capacity may need to be secured to ensure availability.

[10] LSEs' supplies that were not generation or imports could only be inter-SC trades, for which their counter-party had to submit a matching trade. The counter-parties' trades in turn had to be sourced from generation, imports, or another trade (which in turn needs to have a matching trade, until the chain of trades ends with generation or import). In some cases there were instances where a participant sent e-mails indicating that they would have submitted trades with counterparties who did not participate. In such cases where a specific counter –party was identified, import bids for these trades at locations that are historically representative of the counterparties' import points. In cases where the no specific counter-party was identified in e-mail communication (for example counter-party was identified as "market") no import or other source was represented in the analysis.

Table 4: Comparison of Supply vs. Load Responsibility By Industry Sector, for "1-in-2" Scenario

"1-in-2" Scenario	Investor-Owned Utilities	Municipal and Governmental	Other Entities	Total
Forecasted Load	38,116	2,954	4,298	45,368
Scheduled Load	36,589	3,295	2,103[11]	41,987
% of Forecasted Load Scheduled[12]	96%[11]	111%[11]	48.9%	92.5%
Total Forecasted Load + Losses (after new Demand Response)	39,128	2,989	4,421	46,538
Total Generation	16,782	1,585	16,825	35,193
Total Net Import	2,212	1,381	4,476	8,069
Total Net Energy Trade	17,595	328	-17,923	0
Total AS + Supplemental Energy	3,002	318	2,390	5,710
Total Scheduled + Bid Supply	39,591	3,613	4493	48,972
Total Supply (Including Energy Inter-SC Trades) as % of Load[13] (including losses, after new Demand Response)	103.9%	122.3%	104.5%	105.2%

[11] The amounts of scheduled load shown in this table exclude approximately 1250 MW of load that were submitted by generation owners to achieve balanced portfolios including RMR generation that was scheduled as instructed by the CAISO.

[12] The majority of difference between scheduled and forecasted load for the IOUs can be attributed to load scheduling responsibility changes that occurred in 2005 in which the load has either shifted to another control area (i.e. WAPA joining SMUD control area) or scheduling responsibility has shifted from one entity to another. This shift partially accounts for the reason IOU % of forecasted load is below 100% and Municipal and Governmental entities is above 100%

[13] These individual sector values do not account for additional supply bid in by a party in one sector as a result of a contractual arrangement with a party in another sector.

Table 5: Comparison of Supply vs. Load Responsibility By Industry Sector, for "1-in-10" Scenario

"1-in-10" Scenario	Investor-Owned Utilities	Municipal and Governmental	Other Entities	Total
Forecasted Load	41,413	3,210	4,670	49,292
Scheduled Load	39,575	3,467	2,166[14]	45,208
% of Forecasted Load Scheduled[15]	95.5%[14]	108%[14]	46.3%	91.7%
Total Forecasted Load + Losses (after new Demand Response)	42,425	3,244	4,793	50,462
Total Generation	18,158	1,634	17,254	37,046
Total Net Import	2,218	1,493	5,673	9,385
Total Net Energy Trade	19,198	340	-19,538	0
Total AS + Supplemental Energy	2,044	291	2,117	4,452
Total Scheduled + Bid Supply	41,610	3,758	4,262	50,883
Total Supply (Including Energy Inter-SC Trades) as % of Load[16] (including losses, after new Demand Response)	100.5%	117%	92%	100.8%

The observations stated above that (a) enough energy schedules and bids are available in the simulation to serve the forecasted load and losses, but (b) the quantity of submitted energy bids was insufficient to serve the full operating and planning reserve requirements, need to be understood with the following limitations that this simulation has not incorporated limits on resource availability, including but not limited to the following:

(1) There may be limits on how realistic the schedules and bids are. For example, the CAISO's 2005 Summer Assessment found that total wind generation averaged less than 100 MW during system peaks in September 2004, but submitted wind generation schedules exceed this amount.

(2) No forced outages of the offered resources have been imposed. Based on Table II-1 of the CAISO's 2005 Summer Assessment, 3,205 MW of forced outages of participating thermal and hydroelectric resources can be assumed. The Summer Assessment also estimates that scheduled outages may amount to 579 MW; as of the date of this report, 363 MW of scheduled outages and derates have been reported in the CAISO's outage reporting system for the simulation date of 8/17/05, which have generally been reflected in the schedules and bids submitted for this simulation. (Table 6 below includes the effect of forced outages that have not yet been reported to the CAISO, i.e., 579 – 363 = 216 MW.)

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[14] The amounts of scheduled load shown in this table exclude approximately 1250 MW of load that were submitted by generation owners to achieve balanced portfolios including RMR generation that was scheduled as instructed by the CAISO.

[15] The majority of difference between scheduled and forecasted load for the IOUs can be attributed to load scheduling responsibility changes that occurred in 2005 in which the load has either shifted to another control area (i.e. WAPA joining SMUD control area) or scheduling responsibility has shifted from one entity to another. This shift partially accounts for the reason IOU % of forecasted load is below 100% and Municipal and Governmental entities is above 100%.

[16] These individual sector values do not account for additional supply bid in by a party in one sector as a result of a contractual arrangement with a party in another sector.

(3) Transmission outages have not been imposed.
(4) No limits have been imposed on generation output due to congestion in the transmission network. Based on Table II-1 of the CAISO's 2005 Summer Assessment, 1000 MW of intra-zonal congestion constraints could be assumed. Based on optimum power flow analyses described below, this paper finds that at least 90 MW of the resources scheduled and bid in this simulation will be unavailable due to congestion in the "1-in-2" scenario.

Table 6 illustrates some of the adjustments that may affect the actual availability of supply resources. If only these limitations affect the availability of resources during the 2005 summer peak, the 5.2% reserve margin shown in Table 3 would become 3.3%, for the "1-in-2" scenario. The likelihood of these limitations occurring is what drives the need for a planning reserve margin of approximately 15%.

Table 6: Supply Adjustments

	Supply Adjustments (MW)	
	1-in-2	**1-in-10**
Unadjusted Total Scheduled + Bid Supply	48,972	50,883
Wind Generation Schedules (in excess of CAISO total of 100 MW)	-225	-245
Congestion	-90	TBD
Additional Planned Outages	-216	-216
Forced Outages	-3,205	-3,205
Total Adjustments	-3,736	Assume 3,756[17]
Adjusted Supply (Scheduled + Bid)	45,236	47,127
Adjusted Reserve Margin: Total Supply as % of Load (including losses, after new Demand Response)	-2.8%	-6.6%

After assembling the schedules and bids that were submitted by SCs, this simulation has tested for schedule feasibility using an optimum power flow model similar to the one used in the CAISO's Locational Marginal Price (LMP) Studies.[18] Transmission congestion constrains the availability of generation in 6 locations in the "1-in-2" scenario and 12 locations in the "1-in-10" scenario, mostly within the CAISO control

[17] This figure assumes the same amount of capacity is unavailable due to congestion in the "1-in-10" scenario as in the "1-in-2" scenario. Instead, initial tests using the CAISO's optimum power flow model indicate that more capacity will unavailable in the "1-in-10" scenario.

[18] The results of the CAISO's LMP Studies are available at http://www.caiso.com/docs/2004/01/29/2004012910361428106.html. The methodology used here is the same in most ways as described in the published report for LMP Study 3A. Differences include updating the network model to Summer 2005 conditions, using a $500/MWh energy bid price for reserved ancillary services (to ensure that other economic bids are used first), using a $10,000/MWh energy bid price for generation capacity exceeding the schedules and bids submitted by SCs (to ensure that the model does not assume that out-of-market energy is available), raising the limit on shadow prices for overloaded transmission constraints to encourage enforcement of all limits rather than allowing the limits to become soft, and using DC OPF (with losses included in loads) rather than AC OPF in order to avoid uncertainty in reactive power flows having unrealistic impacts on branch capacity. The model uses the full "1-in-2" and "1-in-10" forecasts of load, distributed among the local areas used in LMP Study 3A in proportion to loads during the 2004 summer peak.

area.[19] In the "1-in-2" scenario, the congestion was able to be resolved by reducing schedules of some resources, and using submitted energy and ancillary service bids for other resources.[20] However, the result of congestion is that at least 90 MW of schedules had to be adjusted to resolve congestion in the "1-in-2" scenario, meaning that less supply is available in practice than was submitted by SCs. In the "1-in-2" scenario, transmission between external control areas and the CAISO becomes constrained only on the Westwing branch group (LUGOWSTWG_BG).[21] Table 7 shows the utilization of the branch groups that are used in the CAISO's current zonal market.

In order to determine the impact of an outage of major generators in Southern California and Northern California, additional scenarios assume forced outages of San Onofre Nuclear Generating Station (SONGS) unit 2 in Southern California (1123 MW capacity) and a single 115 kV transmission line east of Tesla substation in Northern California. The loss of SONGS unit 2 reduces the CAISO's reserve margin from 5.2% to 2.8%, without accounting for reductions in resource availability such as congestion; this level of reserves places the CAISO well into a Stage 2 emergency. Two additional transmission constraints become potentially binding, including the South of Lugo limit in Southern California. Loss of the single 115 kV transmission line east of Tesla causes overloads of three other 115 kV lines in the nearby area. For context, 18 transmission outages were in progress during the CAISO's 2004 summer peak.

[19] This is a preliminary result that is subject to change as the simulation results are reviewed further. Further review may reveal any or all of the following: (a) constraints that are heavily loaded but not overloaded in initial analyses, and become binding constraints in the event that any changes in inputs occur, (b) constraints that are not overloaded under normal operating conditions, but would be overloaded in the event that critical outages occur, thereby imposing additional limits on system dispatch to avoid potential overloads due to these contingencies, and (c) constraints that initially appear to be binding but should not actually be enforced because the network model data used in the simulation cannot be validated by data on the actual network loading during the 2004 system peak. For example, an initial review of contingencies for critical outages in the 1-in-2 scenario would add an additional location of transmission constraints and make other constraints more restrictive than in the generation dispatch using only normal conditions.

[20] Further analysis is required before discussion of these results would be meaningful for the 1-in-10 scenario.

[21] In addition, transmission constraints within the CAISO Control Area affect the optimal dispatch of other resources, with the result in this simulation that 12.6 MW of energy bids at Mead are not dispatched when the constraints are enforced. In the optimal dispatch, whether this reduction would occur at this or a different location is a result of the relative bid prices.

TABLE 7: MARKET BRANCH GROUP UTILIZATION

A. Branch Group	From Zone	To Zone	MW Limit (MW)	1-in-2 Flow (MW)	1-in-10 Flow (MW)
ADLANTOSP_BG	LA7	SP15	1036	969	1030
BLYTHE _BG	LC2	SP15	218	208	204
CASCADE _BG	NW2	NP15	80	0	0
CFE _BG	MX	SP15	800	150	280
COI _BG	NW1	NP15	4300	2917	2816
CTNWDRDMT_BG	SMD3	NP15	320	-66	-89
CTNWDWAPA_BG	SMD2	NP15	1594	527	556
ELDORADO _BG	AZ2	SP15	1555	1034	1242
GONDIPPDC_BG	SR4	LA5	54	0	0
IID-SCE _BG	II1	SP15	600	561	561
IID-SDGE _BG	II2	SP15	225	0	0
INYO _BG	LA3	SP15	56	0	0
IPPDCADLN_BG	LA5	LA7	647	607	607
LAUGHLIN _BG	NV3	SP15	0	0	0
LLNLTESLA_BG	SMD8	NP15	148	35	46
MCCLMKTPC_BG	LA6	LC4	694	0	0
MCCULLGH _BG	LA2	SP15	2598	-136	-136
MEAD _BG	LC1	SP15	1460	70	722
MEADMKTPC_BG	LC5	LC4	263	145	157
MEADTMEAD_BG	LC6	LC5	182	19	59
MERCHANT _BG	NV4	SP15	645	480	480
MKTPCADLN_BG	LC4	LA7	423	362	423
MONAIPPDC_BG	PC1	LA5	564	75	75
N.GILABK4_BG	AZ5	SP15	240	106	106
NOB _BG	NW3	SP15	1336	868	952
OLNDAWAPA_BG	SMD1	NP15	850	418	409
PALOVRDE _BG	AZ3	SP15	2823	1720	2158
PARKER _BG	LC3	SP15	220	160	160
PATH15 _BG	ZP26	NP15	5400	2362	3158
PATH26 _BG	SP15	ZP26	-4000	-1298	-634
RNCHLAKE _BG	SMDE	NP15	1291	336	347
SILVERPK _BG	SR3	SP15	17	12	12
SUMMIT _BG	SR2	NP15	59	0	0
SYLMAR-AC_BG	LA1	SP15	1700	-19	81
TRACYWAPA_BG	SMD4	NP15	1700	-661	-771
TRCYHRDLN_BG	SMD7	NP15	9999	404	396
TRCYTESLA_BG	SMD5	NP15	9999	352	453
TRCYWSTLY_BG	SMD6	NP15	650	404	396
VICTVL _BG	LA4	SP15	1526	30	55
WSTWGMEAD_BG	AZ6	LC5	126	126	98

The import from into NP15 from external control areas in the 1-in-2 scenario and 1-in-10 scenario is 4666 MW and 4559 MW respectively. The import into the SP15 from external control area in the 1-in-2 scenario and 1-in-10 scenario is 7547 MW and 9326

MW respectively. If one includes scheduled flows across Path 26, the total import into SP15 in the 1-in-2 and 1-in-10 scenario is 8845 MW and 9960 MW respectively.

Appendix A:
Summary Analysis of Supply/Demand Difference Identified in the 2005 Peak Day Simulation

Introduction

On Tuesday May 3, 2005, the California ISO and its Scheduling Coordinators conducted a 2005 Summer Peak Day Simulation to gain additional operational insight into the quantity and deliverability of supply arranged to meet the expected peak load demand conditions this summer. The simulation was essentially a test of the California ISOs ability to meet this summer's peak hourly demands under varying temperature scenarios using both the expected transmission and generation. The simulation represented a collaborative effort between the California ISO and Market Participants (i.e. Certified and active Scheduling Coordinators) to better understand and prepare for what may well be challenging summer operations.

Scheduling Coordinators were asked to submit generation schedules, load schedules, inter-SC trade schedules, ancillary service schedules, and bids for excess generating capacity (both Ancillary Services and Balancing Energy) representing their self-supply and contractual arrangement that are they expect to rely on during peak-day conditions. As the benchmark against which the CAISO conducted its analysis, the ISO generated two sets of load forecasts representing (1) one-in-two (50% likelihood) summer peak demand of 53,519 MW and (2) the less likely but possible one-in-ten (10% likelihood) summer peak forecast of 58,031 MW (Both forecasts include Total Load + Losses + 15% Planning Reserve).

Results of the simulation were largely consistent with the analysis published by the California ISO in its 2005 Summer Assessment Report. However, analysis of the simulation revealed as much as a 5,510 MW difference between the ISOs forecasted loads and the generation scheduled to supply those loads. This report summarizes our subsequent analysis of that difference.

Questions Posed

To better understand this difference, the ISO conducted some follow-up discussions with Scheduling Coordinators. The ISO submitted a series of questions to seven SCs – four representing Load Serving Entities (LSEs), and three representing generating capacity and imports (Suppliers) -- wherein they were asked to help us understand the difference. Following are the questions submitted to SCs for which we requested a response.

B. Suppliers:

1. We are finding some of the generation resources in your portfolio not scheduled or bid.

   a. Please explain why you did not schedule and bid these resources?

   b. If resources are not contracted with LSE in CAISO is resource contracted elsewhere.

   c. Will the resource be available this summer?

d. If resources will be available will they be available to meet CAISO load? Or for export? Or both depending on the market?

e. If resources are already committed for export from CAISO. How much export is planned for this summer?

2. Based on the 2005 Peak Day Simulation conference call held on May 31, there was indication that some resources were scheduled and or bid into the simulation even though they may not have a contract obligation to do so this summer.

a. Are there any and if so what resources did you schedule and/or bid into simulation for which you do not have contractual obligation to do so?

b. Will these resources that you have now identified as not having a contractual obligation be available for this summer?

3. Is there any other capacity that you have contractual arrangements for serving in area (CAISO) demand or exports which you did not schedule or bid? Why? Where? How Much?

C. Load Serving Entities

1. We have observed that you did not schedule all of the load that we had forecasted in the simulation.

a. Do you have an issue with our forecasted load?

b. Why the difference from last years peak?

c. If your load responsibility has decreased from last year, who is now responsible for the difference in load? In what area does the changes in load responsibility exist (PG&E, SCE or SDG&E area)?

d. Have you made arrangements to meet your load obligation? Or do you plan to?

e. What additional resources and arrangements have you made? Do you plan to?

f. How much and when to expect to be fully resourced to meet your load obligation?

g. Do you intend to have enough resources contracted to meet 115% of peak load? How do you intend to deal with forced outages and contingency events?

h. What steps have you taken to ensure your supplies are deliverable?

2. Based on our conference call today there was indication that some resources were scheduled and or bid into the simulation even though they may not have a contract obligation to do so this summer

a. Are there any trades that you made in the simulation for which you did not have a contractual arrangement for?

b. Are there any additional arrangements that you have not already expressed in the simulation.

Responses

1. Suppliers

Three SCs (Generators) note that a fraction of their respective portfolios generating capacity was not scheduled into the simulation because only a fraction of the total capacity has been sold. They scheduled into the Simulation accordingly. They further note that this may change between now and the summer peak months.

Two SCs (Generators) are considering the option of selling their uncommitted capacity to parties outside of the California ISO Control Area and/or outside of California. Each conditioned this on the inability to find local counter-parties willing to make contract for the capacity. As well, one noted that parties outside of California have inquired about the willingness to sell outside of California.

Two SCs (Generators) indicate that generation schedules submitted during the simulation do not represent current commitments. Rather than submit the excess capacity in the simulation as a bid for supplemental energy capacity or Ancillary Service Bids, they scheduled it as generation to another counterparty to balance their portfolio.

D. Load Serving Entities

Several of the Load Serving Entity (LSE) Scheduling Coordinators (SCs) stated that they participated to the level of their present power contracts, as instructed by the ISO in the Simulation's Plan. Some LSEs indicated that their customers, typically do not "hedge" out more than three months, and have yet to secure their August power supplies. Accordingly, these LSEs only scheduled their load presently under bi-lateral contract for Summer 2005. One indicated that they fully expect their large industrial customers to contract soon for August and that they anticipate a load portfolio at or in excess of the Summer 2004 based ISO forecast for this SC.

Other LSEs indicated that portions of their 2004 Direct Access portfolio, the basis of the ISO's 2005 forecasts, had returned to the Investor Owned Utility (IOU), or transferred to another Direct Access (DA) provider. Several indicated that they attempted to participate at 100% of their ISO forecasted loads as instructed, and have sufficient power under contract for Summer, but the other party's SC had refused to fully schedule the source side of these bi-lateral energy transactions. In these cases, the LSE could only balance that portion of their 2005 load, actually scheduled in the Simulation by another SC and "traded" to the LSE in the ISO scheduling system.

A number of MPs choose not to participate or could not participate and gave several explanations. First, a number of Marketer-Broker (MB) SCs expressed concern for NOT revealing their respective "positions" in the markets, so as not to compromise their bargaining positions as summer approaches and they attempt to "book out" their portfolios, and to buy or sell, if "short" or "long".

Another category of non-participants simply could not free up the front line Scheduling personnel, from their regular daily market activities, negotiation of bi-lateral energy purchases and sales, book-out, scheduling, electronic tagging, submission of final schedules to the various Markets, Control Areas and other ISO's, to allow these Marketer-Broker operations to participate. Several ISO MB participants are relatively small operations, but move significant amounts of bi-lateral traded power and thus consumed by their day-to-day activities to compete. This may account for several of the large DA LSEs inability to fully schedule their bi-lateral contracts in the simulation.

Two other Load Serving Entities, simply erred in under-scheduling their completely contracted loads, and subsequently apologized for the mistake. In one case, an LSE attempted to participate but hit an ISO spam filter.

These Marketer-Brokers and LSEs generally followed ISO simulation instructions by scheduling that power, under contract, at present for the two peak August Summer Simulation 2005 loading scenarios.