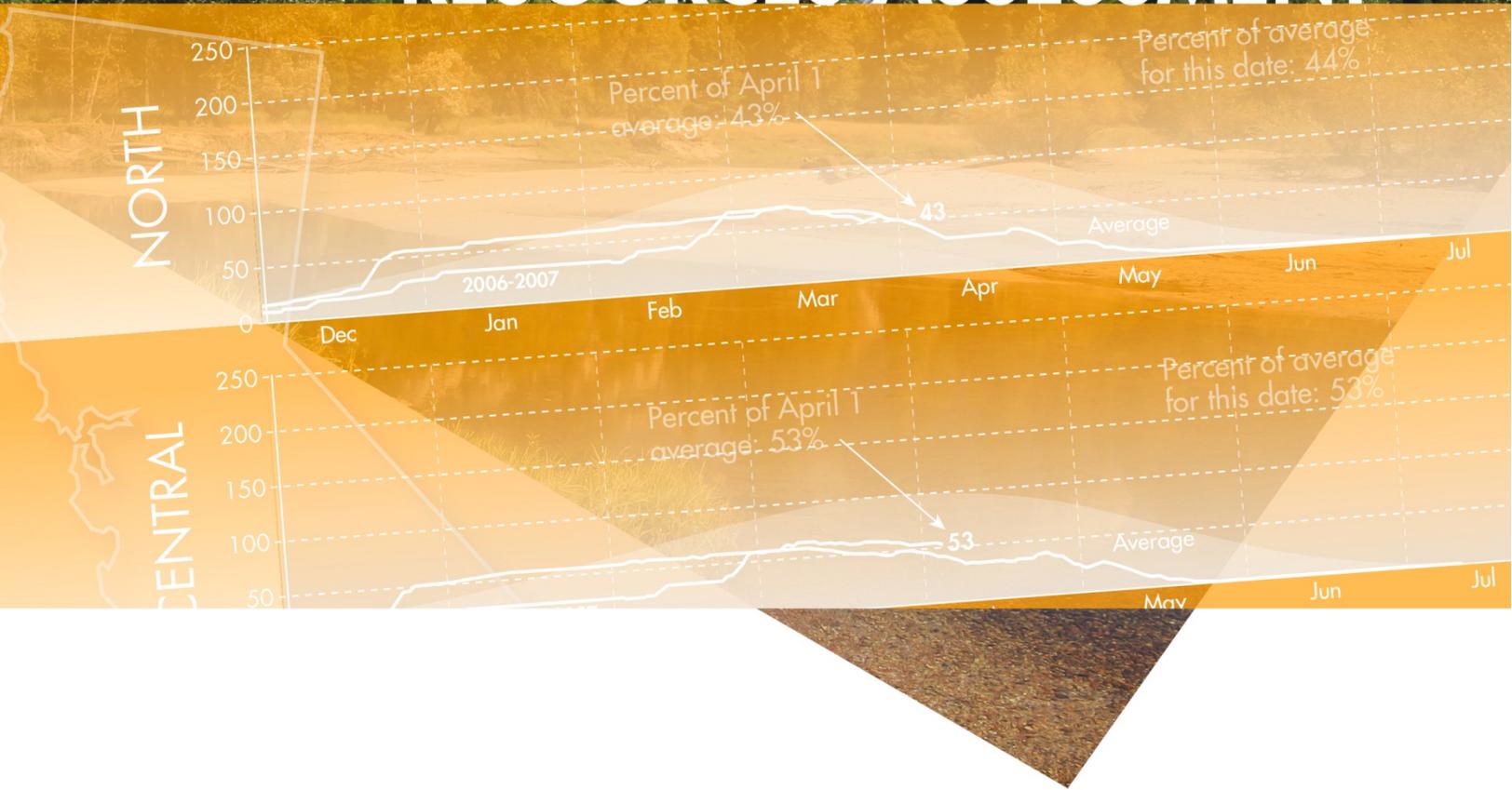


2014 SUMMER LOADS & RESOURCES ASSESSMENT



California ISO

Shaping a Renewed Future

May 9, 2014

Prepared by: Infrastructure Development

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I. EXECUTIVE SUMMARY

The *2014 Summer Loads and Resources Assessment* provides an analysis of the upcoming summer supply and demand outlook in the California Independent System Operator (ISO) balancing authority area. The ISO works with state agencies, generation and transmission owners, load serving entities, and other balancing authorities to formulate the summer forecast and identify any issues regarding upcoming operating conditions. The loads and resources assessment considers the conditions across the entire ISO balancing authority area as a whole (representing about 80 percent of California), and then further considers separately the situations in the Northern California zone (North of Path 26 or NP26) and the Southern California zone (South of Path 26 or SP26). The drought impact in California on power supply and local reliability concerns for southern Orange and San Diego counties due to the loss of the San Onofre Nuclear Generation Station are two of the key issues in 2014 and are addressed in this report

Impact of California Drought on Summer Power Supply

The 2014 water year is one of the most severe droughts on record according to California Department of Water Resources. As of April 29, 2014, the statewide hydrologic conditions were summarized as: 56% of average precipitation; 20% of average snowpack water content; and 63% of average reservoir storage.¹ These drought conditions will limit the capability of the state's hydroelectric resources and may cause up to 1,150 MW of thermal units to shut down due to water supply curtailments.²

However, these potential supply limitations should not materially impact the reliability of the ISO system this summer due to significant generation additions, sufficient energy imports, and moderate peak demand growth. The main impact from the drought during 2014 summer will be an increase in natural gas generation, which could result in an increase in energy prices, and increased greenhouse gas emissions. However, the unusually dry conditions across the state do create a heightened risk of wildfires, which could impact the use of major transmission lines during periods of critical summer peak demand. Thus, wildfires could create grid reliability challenges over the summer. Some of the key factors supporting this conclusion are summarized below.

¹ <http://cdec.water.ca.gov/cgi-progs/reports/EXECSUM>

² Climate change studies suggest this is the start of a long-term trend toward drier, hotter conditions in California. This trend in addition to increasing deployment of renewable resources underscores the importance of ensuring California has adequate grid infrastructure going forward to both offset the impacts of climate change and effectively integrate renewable resources. To address this challenge, the ISO is taking a more sophisticated approach to system planning where generic capacity and traditional planning reserve margins are less relevant and the primary focus is on ensuring California has sufficient dispatch and flexibility capabilities within the resource fleet to reliably operate the system and achieve state energy policy goals. This study work is being used in ongoing CPUC proceedings to inform resource procurement decisions.

- **ISO Hydro Generation Derate**

In the Final Net Qualifying Capacity (NQC) Report for Compliance Year 2014³, ISO total hydro NQC in August is 7,666 MW (capacity available for peak based on state's resource adequacy program). The NQC is the maximum capacity eligible and available for meeting the CPUC resource adequacy requirement. The ISO determines the NQC by applying performance criteria and deliverability restrictions as outlined in the ISO tariff and the applicable business practice manual. However, as a result of the drought, and based on discussions held with Pacific Gas and Electric and Southern California Edison, the two largest hydro capacity owner/operators in the ISO, the ISO has determined that a hydro derate in the amount of 1,370 MW (normal scenario) to 1,669 MW (extreme scenario) should be applied to the net qualifying capacity of 7,666 MW. There is only 44 MW of NQC hydro generation located in San Diego and Orange Counties and the majority of this generation is pumped storage. Consequently, drought conditions will have little impact on local resource adequacy in the San Diego and Orange County areas.

- **Potential Thermal Restriction**

In considering the drought situation for the summer of 2014, the ISO is following the potential impact of thermal units being out of service due to water supply curtailments. Among the 260 thermal power plants greater than 20 MW, three facilities in Northern California totaling 1,150 MW have been identified to be at risk of having water supply curtailments. The ISO will work with state and local agencies to monitor these facilities through the summer. Water supplies to thermal generation will likely be of a greater concern in 2015 if the current drought continues.

- **Imports from Outside California**

As of April 29, 2014, Northwest River Forecast Center projected April to August reservoir storage in Columbia - Dalles Dam to be 107% of average.⁴ The Pacific Northwest hydro surplus energy sales into the ISO are anticipated to be in the normal to above normal range for 2014 to make up for some of California's low hydro generation. The California – Oregon Intertie (COI) thermal limit could be a limiting factor for these imports. It is anticipated that dynamically scheduled and other generation from the Four Corners will be available for surplus energy sales into the ISO during the peak hours. The Southern California Import Transmission (SCIT) thermal limit could be a limiting factor for these imports.

- **Natural Gas and Solar Generation Additions**

A total of 3,243 MW additional generations are expected to enter commercial operation by June 1 2014, 2,258 MW in SP26 and 985 MW in NP26, This 3,243 MW comes from 3,555 MW of new generation that went into commercial operation since last summer, the retirement of the 650 MW of generation at Morro Bay, and an additional 338 MW that is expected to become commercial operation by June 1, 2014.

³ *Net Qualifying Capacity (NQC)*. Retrieved from website:
<http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx>

⁴ http://www.nwrfc.noaa.gov/water_supply/ws_forecasts.php?id=TDAO3

Of the 3,243 MW, 61% is solar, 32% is natural gas, and 7% is in other categories. This will help to offset the anticipated hydro derate in 2014.

Local Reliability Concerns due to SONGS Outage

The permanent retirement of the San Onofre Nuclear Generating Station was announced on June 7, 2013. This further validated the steps taken in 2012 to prepare the system for the summer of 2013 in anticipation of SONGS not returning to service. Those steps included the completion of several transmission and voltage support enhancements in the LA Basin area.

While additional approved mitigations are expected to begin coming into service for the summer of 2015, no additional transmission measures are available for the summer of 2014. With continued modest load growth, local reliability conditions in the south Orange and San Diego counties are likely to be marginally more challenging this summer compared to last.

If critical high-voltage transmission lines are out of service, due to wildfires or other conditions, deficient voltage levels may occur under peak load conditions that could trigger localized customer outages. Furthermore, the absence of SONGS results in potential overloading of local transmission lines under certain contingencies.

Until longer term mitigations are in place, southern Orange County and San Diego will remain susceptible to reliability concerns and will require close attention during summer operations – particularly during critical peak days and in the event of wildfires that could potentially force transmission lines out of service.

During these types of conditions, both demand response programs and Flex Alert conservation appeals will likely be used to lessen the strain on the grid.

Overall ISO System-wide and Zonal Reliability

Even with the drought concerns, the summer assessment projects adequate supply for meeting 2014 summer peak demand for the ISO grid at the system wide level and for the NP26 and SP26 regions when considered independently. This projection is based on examining the operating reserve margins under normal and extreme scenarios.

The summer 2014 supply and demand outlook for the entire ISO system, NP26 and SP26 are shown in *Tables 1 through 3*. Planning reserve margins under the normal peak demand scenario are projected to be 34.4% for the ISO system, 35.9% for SP26, and 36.3% for NP26 (*Table 1*).

Operating reserve margins under the normal summer conditions are expected to be 23.8% for the ISO system 28.2% for SP26, and 22.7% for NP26 (*Table 2 and Figure 1*). Both the planning reserve margin and the normal operating reserve margin are projected to be greater than the California Public Utility Commission's 15% resource adequacy requirement for planning reserve margin.

The 2005 to 2014 operating reserve margins under the normal scenario projected prior to each summer are shown in *Figure 2*. It is worth mentioning that the operating reserve margin projected for 2014 is the second largest in the past ten years. The normal scenario for operating reserves is defined for system and zonal conditions as moderate

net imports, 1-in-2 generation outages, and 1-in-2 peak demand. A 1-in-2 event means the event has an equal probability of the outcome falling below the forecast value or exceeding the forecast value.

Under an extreme scenario, operating reserve margins are projected to drop to 13.6% for the ISO system, 15.1% for SP26 and 7.6% for NP26 (*Table 3* and *Figure 1*), which are above the firm load shedding threshold of 3%. The extreme scenario is defined as low net imports, 1-in-10 generation outages, and 1-in-10 peak demand. A 1-in-10 event means the event has a 90% probability of the outcome being less than or equal to the forecast value, or conversely, a 10% probability of the outcome being greater than or equal to the forecast value. Operating reserve margins for each zone are for informational purposes as the system is dispatched on a one-system basis. The methodology for assessing transfers between the NP26 and SP26 zones that has been employed in this and past Summer Assessments is based on historical flows, which does not adequately address evolving conditions with drought impacts most strongly felt in NP26. A revised methodology utilizing modeled transfers under projected load and resource scenarios will be employed in next year's Summer Assessment.

The projected probability of experiencing involuntary load curtailments due to low operating reserve margins in summer 2014 is 0% for ISO system, 0% for SP26 and 0.1% for NP26, assuming moderate imports and a high hydro derate. These projected probabilities are based on historical generating resource availabilities and the forecast range of weather driven peak demand levels and do not include load curtailments due to transmission lines being out of service due to wildfires or other contingencies.

The ISO summer 2014 peak demand is projected to reach 47,351 MW during 1-in-2 weather conditions, which was 646 MW more than 2013 weather normalized peak of 46,705 MW. The weather normalized peak is an estimate of what the peak would have been under normal weather conditions. The increase in the ISO peak demand forecast is a result of a moderate economic recovery forecast from Moody's Analytics.

The ISO projects that 53,950 MW of net qualifying capacity (NQC) will be available for summer 2014 (*Table 7*). A total of 3,243 MW of additional generation since last year's report is made up of 3,555 MW of new generation that reached commercial operation and the retirement of 650 MW of generation at Morro Bay between June 1, 2013 and April 22, 2014 and an additional 338 MW that is expected to become commercial operation during April 23, 2014 to June 1, 2014 timeframe.

An estimated 2,066 MW of demand response and interruptible load programs will be available to be deployed during summer 2014. Demand response can reduce summer peak demands and provide grid operators with additional system flexibility during periods of limited supply. Demand response can provide economic day-ahead and real-time energy and ancillary service.

The 2014 summer imports are projected to vary from 8,500 MW to 11,000 MW for the ISO, 8,800 MW to 11,300 MW for SP26, and 1,300 MW to 3,000 MW for NP26. The projected 2014 moderate imports for the ISO is 9,000 MW, which is lower than last year. Having sufficient imports are essential in maintaining system reliability under extreme conditions.

Table 1
Planning Reserve Margins

Summer 2014 Supply & Demand Outlook (Planning Reserve Margins)			
Resource Adequacy Planning Conventions	ISO	SP26	NP26
Existing Generation ⁵	53,612	26,178	27,434
Retirement	0	0	0
High Probability Addition ⁶	338	261	77
Hydro Derate (below NQC)	(1,370)	(281)	(1,089)
Net Interchange (Moderate) ⁷	9,000	9,200	2,100
Total Net Supply (MW)⁸	61,580	35,358	28,522
DR & Interruptible Programs ⁹	2,066	1,341	725
Demand (1-in-2 Summer Temperature) ¹⁰	47,351	26,994	21,452
Planning Reserve Margin¹¹	34.4%	35.9%	36.3%

Table 2
Normal Scenario Operating Reserve Margins

Summer 2014 Outlook - Normal Scenario 1-in-2 Demand, 1-in-2 Generation Outage and Moderate Imports			
Resource Adequacy Conventions	ISO	SP26	NP26
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
Hydro Derate (below NQC)	(1,370)	(281)	(1,089)
Outages (1-in-2 Generation) ¹²	(5,030)	(2,105)	(2,921)
Net Interchange (Moderate)	9,000	9,200	2,100
Total Net Supply (MW)¹³	56,550	33,253	25,601
DR & Interruptible Programs	2,066	1,341	725
Demand (1-in-2 Summer Temperature)	47,351	26,994	21,452
Operating Reserve Margin¹⁴	23.8%	28.2%	22.7%

⁵ Refer to Table 7. Conventional 74%, Renewable 26%.

⁶ Refer to Table 6.

⁷ Refer to Table 10. Net Interchanges of ISO, SP26 and NP26 are not coincident.

⁸ Total Net Supply = Existing Generation + High Probability Additions – Hydro Derate – Retirements + Net Interchange

⁹ Refer to Table 11.

¹⁰ Refer to Table 12.

¹¹ Planning Reserve Margin = [(Total Net Supply + Demand Response + Interruptible) / Demand] – 1

¹² Refer to Table 8. Outages of ISO, SP26 and NP26 are not coincident.

¹³ Total Net Supply = Existing Generation + High Probability Additions – Hydro Derate – Retirements – Outages + Net Interchange

¹⁴ Operating Reserve Margin = (Total Net Supply + Demand Response + Interruptible) / Demand - 1

Table 3
Extreme Scenario Operating Reserve Margins

Summer 2014 Outlook - Extreme Scenario			
1-in-10 Demand, 1-in-10 Generation Outage and Low Imports			
Resource Adequacy Conventions	ISO	SP26	NP26
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
High Hydro Derate (below NQC)	(1,669)	(342)	(1,328)
High Outages (1-in-10 Generation)	(6,478)	(3,406)	(4,126)
Net Interchange (Low)	8,500	8,800	1,300
Total Net Supply (MW)	54,303	31,491	23,357
DR & Interruptible Programs	2,066	1,341	725
High Demand (1-in-10 Summer Temperature)	49,601	28,522	22,377
Operating Reserve Margin	13.6%	15.1%	7.6%

Figure 1

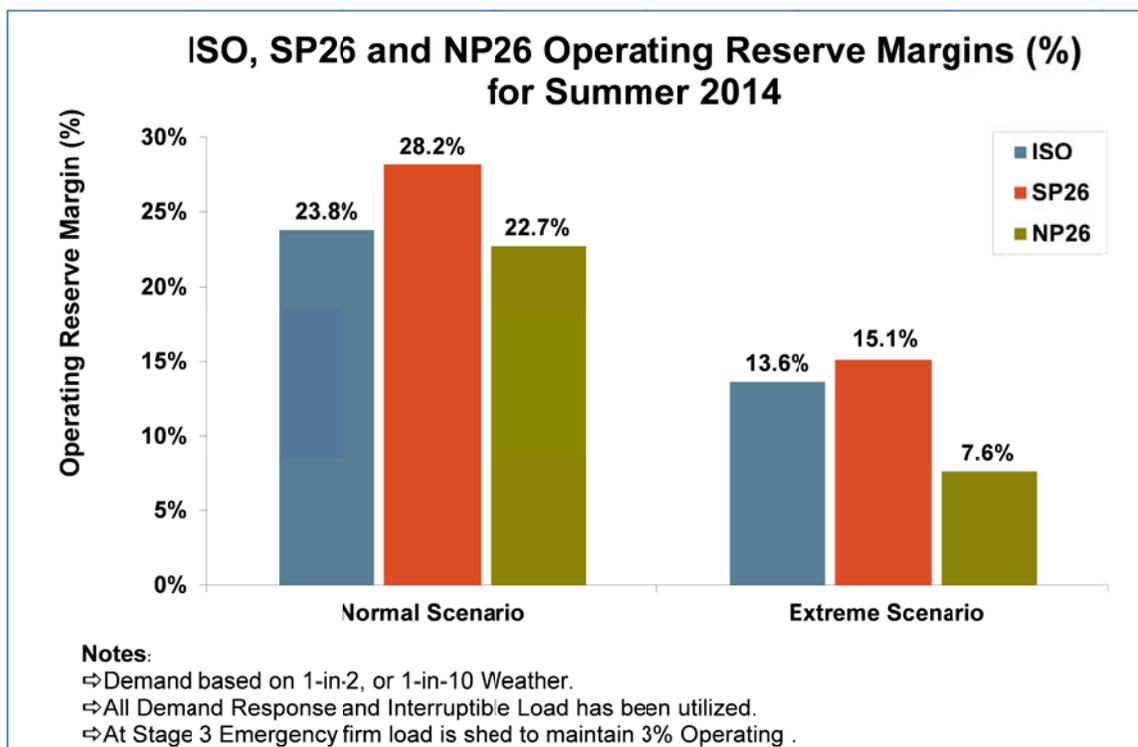


Figure 1 shows adequate operating reserve forecast margins under the normal and extreme scenarios. The operating reserve margins for ISO, SP26 and NP26 are projected to be above the 3% firm load shedding threshold in all scenarios.

Figure 2



Figure 2 shows forecasts of normal operating reserve margins have remained ample and fairly consistent since 2009.

Producing this report and publicizing its results is one of many activities the ISO undertakes each year to prepare for summer operations. Other activities include coordinating meetings on summer preparedness with the WECC, Cal Fire, natural gas providers and neighboring balancing authorities. The ISO's ongoing relationships with these entities help to ensure everyone is prepared during times of system stress.

Significant amounts of new renewable generation has reached commercial operation and this trend is expected to continue as new renewable generation comes online to meet the state's 33% renewables portfolio standard (RPS). A certain amount of flexible and fast responding resources will need to be maintained on the system to ensure reliable operation in the transition to the RPS.

The roughly 10,517 MW of natural gas fired capacity subject to the once-through-cooling regulation, which will require coastal power plants that use ocean water for cooling to be retired, retrofitted or repowered, is an ongoing issue that also needs to be addressed. The ISO is working closely with state agencies and plant owners in evaluating the reliability impacts of implementing these regulations to ensure electric grid reliability is maintained throughout the transition. The ISO plans to include assessments of the adequacy of flexible capacity in future Summer Loads and Resources Assessment reports.

II. SUMMER 2013 REVIEW

Demand

The recorded 2013 summer peak demand reached 44,941 MW on June 28, 2013. Adjusting for the normalized weather conditions, this translates into a peak load of 46,705 MW for ISO in 2013, an increase of 30 MW, or 0.06% from the 46,675 MW of 2012 summer peak demand. The SP26 summer peak demand was 27,058 MW and NP26 peak demand reached 20,928 MW. The annual peaks for the ISO, SP26 and NP26 happened on June, July and September, respectively. The fact that the annual peaks did not occur coincidentally is due to a number of factors, with weather being the primary contributing factor.

Figure 3 shows ISO, SP26 and NP26 actual monthly peak demand from 2006 to 2013. The ISO summer peak dropped each year from 50,085 MW in 2006, which was high because of extreme weather conditions and a stronger economy, to 45,809 MW in 2009 as demand moderated during the recession. Demand has fluctuated since 2009 based on changing economic, demographic, and weather conditions. The ISO, SP26 and NP26 daily peaks from June to September 2013 are shown in *Appendix A: 2013 Summer Peak Load Summary Graphs*.

Figure 3

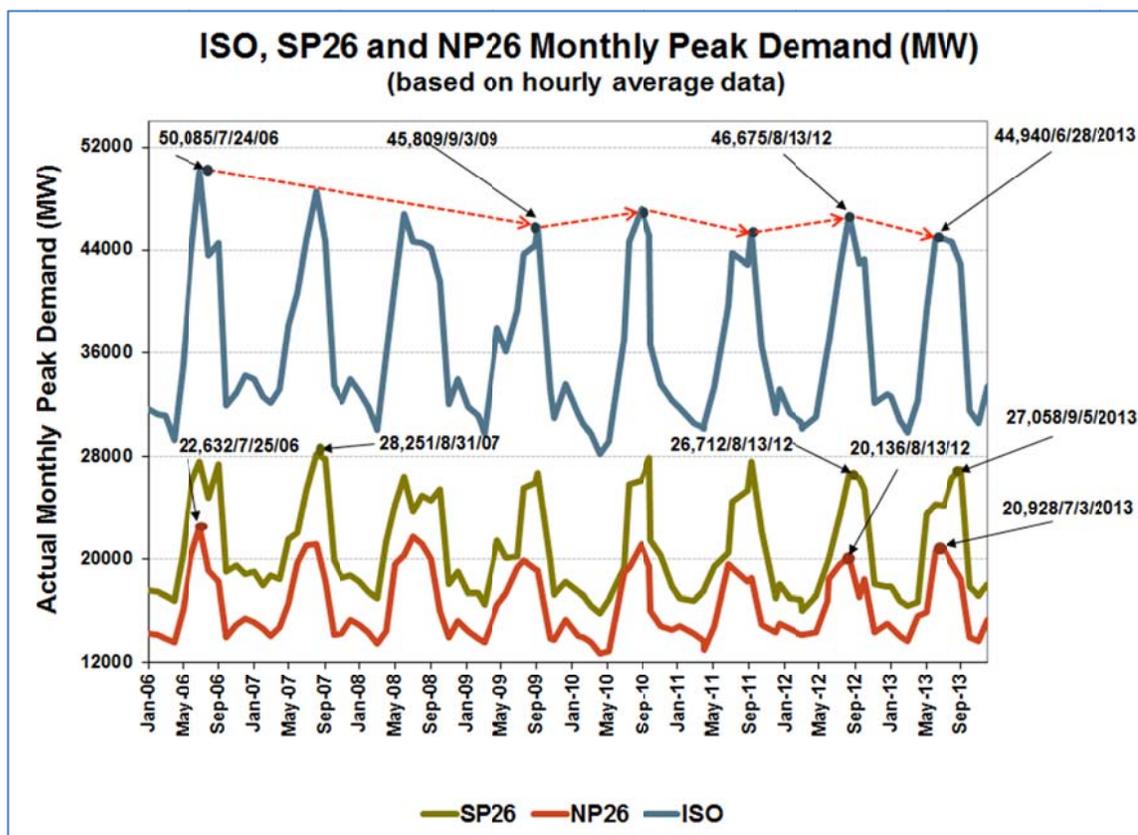


Figure 3 shows the ISO balancing authority system peak as well as peaks for Northern and Southern California. Starting in 2006, the summer ISO peak demand gradually declined to 2009, somewhat rollercoaster from 2009 to 2013.

Table 4 shows the difference between 2013 actual peak demands and 2013 1-in-2 peak demand forecasts. The ISO peak demand in 2013 was categorized as approximately the 20th percentile or 1-in-1.25 temperature event. The 20th percentile represents a point at which 20 percent of the probable outcomes will be equal to or less than this value. The weather normalized peak load for ISO in 2013 was 46,705 MW.

The actual peak demand in Southern California was 195 MW lower than the 1-in-2 forecast peak demand for SP26. The weather at the time of the SP26 peak demand was the 27th percentile or 1-in-1.38 temperature event. A combination of a mild weather pattern, demand response, and an actual economic growth slower than that forecasted by Moody's was the main contributor to the actual peak demands being lower than 1-in-2 forecast peak demands for ISO and SP26.

The actual peak demand in Northern California was 400 MW lower than 1-in-2 forecast peak demand for NP26. The weather at the time of the NP26 peak demand was the 62th percentile or 1-in-2.63 temperature event. This anomaly was the result of differences in non-weather parameters in the load forecast model, including but not limited to the difference between the realized economic growth in Northern California and the assumptions incorporated into the forecast. The downward impact of these variations from forecast more than offset the upward impact of higher than average temperatures.

Table 4

2013 ISO Actual Peak Demand vs. Forecasts				
	1-in-2 Forecast (MW)	Actual (MW)	Difference from 1-in-2 Forecast (MW)	Difference from 1-in-2 Forecast (%)
ISO	47,413	44,941	-2,472	-5.2%
SP26	27,253	27,058	-195	-0.7%
NP26	21,328	20,928	-400	-1.9%

Generation

As of April 22, 2014, the net dependable capacity of the ISO balancing authority was 65,226 MW, including 32,157 MW in SP26 and 33,069 MW in NP26. The NDC is the maximum capacity of a unit during the most restrictive seasonal conditions less the units' capability used for station service or auxiliaries. It includes the capability of units that may be temporarily inoperable because of maintenance, forced outage, or other reasons, or only operable at less than full output. It excludes power required for plant operation and emergency power for unit startup and shutdown. The net dependable capacity of the ISO balancing authority is shown in *Appendix B 2014 ISO NDC and RPS by Fuel Type*.

Generation in the ISO balancing authority is primarily fueled by natural gas (60.8%), followed by 22.0% renewables portfolio standard (RPS) resources, 12.5% large hydro, 3.5% nuclear units and a small amount of oil and coal. Although SONGS units 2 and 3

totaling 2,246 MW were retired on June 7, 2013, they were excluded in 2013 summer resources and outages calculation. Contra Costa Units 6 and 7 totaling 674 MW were replaced on May 1, 2013 with 800 MW Marsh Landing Generation Station units 1 to 4. Huntington Beach units 3 and 4 were converted to synchronous condensers on December 7, 2012. Morro Bay Units 3 and 4 retired on February 5, 2014. The ISO used the California Public Utilities Commission methodology for determining the components of the renewables portfolio standard generation.¹⁵ The conventional resources included natural gas, nuclear, oil and coal.

Renewables Generation

A total of 14,330 MW renewable commercial operation generations were composed of 41.5% wind, 31.1% solar, 11.0% geothermal, 8.9% small hydro, 4.8% biomass, and 2.9% biogas. Maximum wind generation reached 4,268 MW on June 23, 2013. Maximum solar generation reached 2,893 MW on December 26, 2013. Because California has relatively large share of natural gas generation, a potential shortage of natural gas could create reliability issues on the power grid. Greater fuel diversity through integration of renewable energy resources is helping to mitigate this risk.

Generation Outages

The average weekday generation outages in 2013 were lower than those in 2012, with the most significant contribution to the change coming from the retirement of the SONGS units 2 and 3. ISO average weekday generation outages from June 2013 to September 2013 were 5,104 MW lower than 8,220 MW in 2012. SP26 average weekday outages were 2,341 MW lower than 4,307 MW in 2012. NP26 average weekday outages were 2,178 MW lower than 3,913 MW in 2012.

Graphs in *Appendix C: 2011 – 2013 Summer Generation Outage Graphs* show the weekday hour-ending 16:00 forced and planned outage amounts during the summer peak days from June 15 through September 30 for the 2011, 2012, and 2013 (excluding holidays). The graphs do not include ambient and normal outages as these amounts are accounted for in the NQC listing, based on most likely summer peak weather conditions.

A forced outage is the outage where the equipment is unavailable for unexpected events such as the removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. A planned outage is the outage where the shutdown of a generating unit, transmission line, or other facility, is for inspection or maintenance, in accordance with an advance schedule. An ambient outage is a special type of outage where the cause is due to ambient conditions outside of the resource operator's control. The ambient conditions include exceeding air emission limits, lack of fuel, lack of water, low steam pressure, geomagnetic disturbance, earthquake, or catastrophe. Normal outage is the outage when the unit cannot response to a dispatch due to designed operations.

Imports

Figure 4 shows the 2013 ISO peak and the net interchange over the weekday summer peak load period. There are numerous factors that determine to the level of interchange

¹⁵ Renewable Energy and RPS Eligibility; website:
<http://www.cpuc.ca.gov/PUC/energy/Renewables/FAQs/01REandRPSeligibility.htm>

between the ISO and other balancing authorities at any given point in time (refer to the Imports section on page 20).

The imports at the 2014 summer peak for ISO and SP26 decreased in 2013. The ISO imports at the peak decreased from 9,199 MW in 2012 to 8,780 MW in 2013 and the SP26 imports at its peak decreased from 8,513 MW in 2012 to 8,306 MW in 2013. These decreases were due in part to higher in-state generation dispatch in Southern California in 2013 and low loads due to mild weather. However, the NP26 imports at its peak increased from 997 MW in 2012 to 2,331 MW in 2013. (*Appendix D: 2011 – 2013 Summer Imports Summary Graph*)

Figure 4

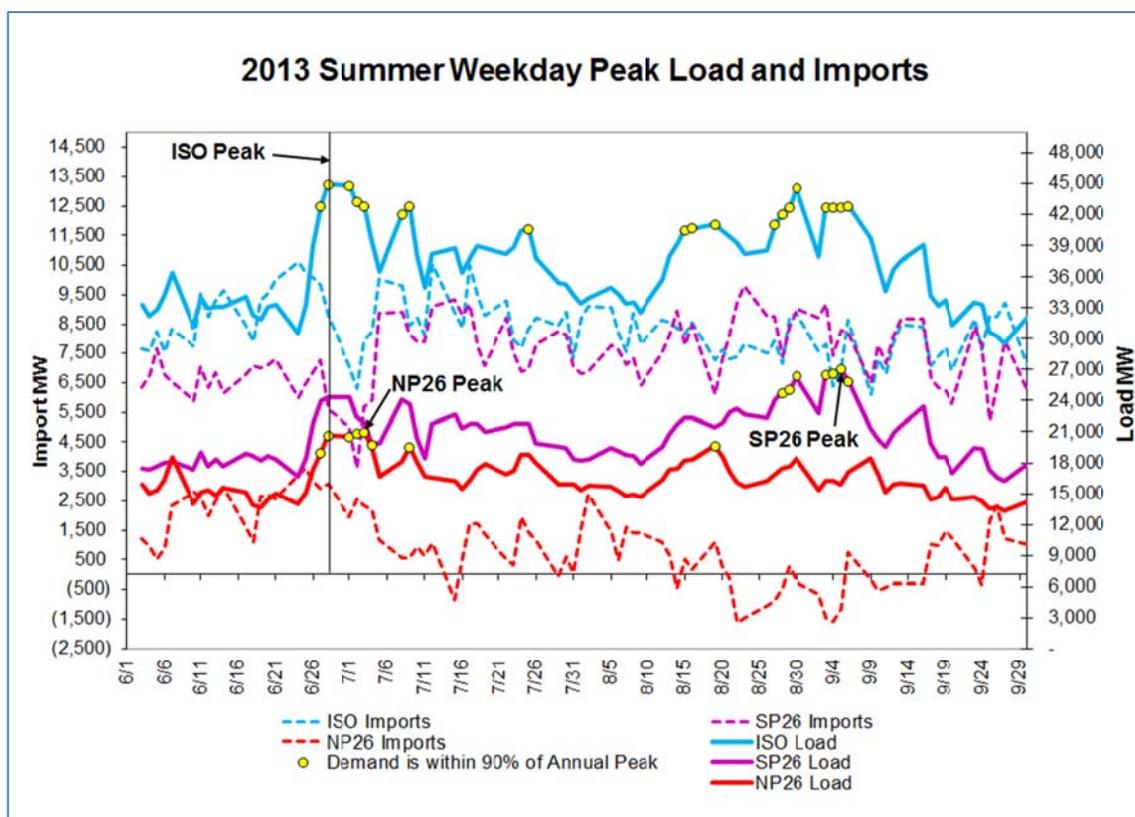


Figure 4 shows the amount of imports at ISO daily system peaks.

III. SUMMER 2014 ASSESSMENT

Generation

Total ISO generation NQC (before hydro derates) for the 2014 summer peak is estimated to be 53,950 MW, a 3,243 MW increase from June 1, 2013. This additional amount will help meet an expected 646 MW of load growth and offset the hydro derate for this summer. Each year, CPUC, the CEC and the ISO work together to publish an NQC list which describes the amount of capacity that can be counted from each resource to meet Resource Adequacy requirements in the CPUC's RA program. To account for the variable output of intermittent resources, the NQC calculation process uses a three-year rolling average of historical production data to determine the NQC for each wind, solar, or other non-dispatchable resource. The NQC for dispatchable resources depends on its availability and deliverability. The ISO determines the net qualifying capacity by testing and verification as outlined in the ISO tariff and the applicable business practice manual.

The largest available generation resource type is natural gas generation accounting for 68.7% and the second largest generation type is hydro accounting for 14.2%. Non-hydro renewables including geothermal, biogas, biomass, wind and solar units make up about 11.7%. With the retirement of both SONGS units nuclear generation accounts for 4.2% while coal and oil generation provide 1.2%. On-peak NQC by fuel type is shown in *Appendix E: 2013 ISO Summer On-Peak NQC Fuel Type*.

Generation Addition and Retirement

Table 5 shows that a total of 3,555 MW of NQC came on line in the ISO balancing authority from June 1, 2013 to April 22, 2014. This new NQC included 1,997 MW in SP26 and 1,558 MW in NP26, and 650 MW from Morro Bay Units 3 and 4 retiring on February 5, 2014. After April 22, 2014, 338 MW of additional net qualifying capacity generation is expected to come on line by June 1, 2014 as shown in *Table 6*, with 261 MW in SP26 and 77 MW in NP26. New generation with zero NQC are not listed in *Tables 5* and *6*.

Table 7 shows the total generation capacity changes within the ISO since June 1, 2013 and expected by June 1, 2014. A total of 3,243 MW of generation additions are expected to enter commercial operation for this summer, 2,258 MW in SP26 and 985 MW in NP26. This table was developed using the final NQC list that was used for the California Public Utilities Commission as part of its resource adequacy program for compliance year 2014, which the ISO posted to its website on March 13, 2014. Generators who chose not to participate in the NQC process were added using the ISO Master Control Area Generating Capability List, which is also posted on the ISO website.¹⁶

¹⁶ Master Control Area Generating Capability List website :
<http://www.caiso.com/participate/Pages/Generation/Default.aspx>

Table 5

New Generating Capacity (MW)						
(Generation that achieved commercial operation from 6/1/ 2013 to 4/22/2014)						
Resource ID	COD	NDC	NQC (est)	Fuel Type	Area	
DEVERS_1_SOLAR1	01-Jun-13	12.0	8.2	SUN	SCE	
DEVERS_1_SOLAR2	01-Jun-13	9.0	6.2	SUN	SCE	
KANSAS_6_SOLAR	06-Jun-13	20.0	13.7	SUN	PGAE	
COCOSB_6_SOLAR	12-Jun-13	1.5	1.0	SUN	PGAE	
OLIVEP_1_SOLAR	22-Jun-13	20.0	13.7	SUN	PGAE	
GATES_2_SOLAR	24-Jun-13	20.0	13.7	SUN	PGAE	
GATES_2_WSOLAR	24-Jun-13	10.0	6.8	SUN	PGAE	
ELSEGN_2_UN2021	29-Jun-13	263.7	263.7	NATURAL GAS	SCE	
ELSEGN_2_UN1011	09-Jul-13	263.0	263.0	NATURAL GAS	SCE	
DAVIS_1_SOLAR1	01-Jul-13	1.0	0.7	SUN	PGAE	
GONZLS_6_UNIT	08-Jul-13	1.4	0.9	LANDFILL GAS	PGAE	
PEABDY_2_LNDFIL	09-Jul-13	1.6	1.0	LANDFILL GAS	PGAE	
SANLOB_1_LNDFIL	21-Jul-13	1.5	0.9	LANDFILL GAS	PGAE	
OCTILO_5_WIND	29-Jul-13	265.0	50.5	WIND	SDGE	
LECEF_1_UNITS	31-Jul-13	315.0	315.0	NATURAL GAS	PGAE	
DAVIS_1_SOLAR2	05-Aug-13	1.0	0.7	SUN	PGAE	
RUSCTY_2_UNITS	08-Aug-13	625.0	625.0	NATURAL GAS	PGAE	
WAUKNA_1_SOLAR	14-Aug-13	20.0	13.7	SUN	PGAE	
VACADX_1_NAS	06-Sep-13	1.9	1.9	BATTERY	PGAE	
TOPAZ_2_SOLAR	09-Sep-13	237.0	162.1	SUN	PGAE	
VISTA_2_FCELL	13-Sep-13	1.4	0.9	AGRICULTURAL WASTE	SCE	
GUERNS_6_SOLAR	18-Sep-13	20.0	13.7	SUN	PGAE	
CSLR4S_2_SOLAR	11-Oct-13	130.0	88.9	SUN	SDGE	
CNTNLA_2_SOLAR1	16-Oct-13	51.5	35.2	SUN	SDGE	
CPVERD_2_SOLAR	22-Oct-13	150.0	102.6	SUN	SDGE	
SOLAR PROJECT	10/22/2013 (COM)	219.7	150.2	SUN	SCE	
CAVLSR_2_RSOLAR	01-Nov-13	210.0	143.6	SUN	PGAE	
ARLVAL_5_SOLAR	05-Nov-13	127.0	86.8	SUN	SDGE	
GLDTWN_6_SOLAR	18-Nov-13	5.0	3.4	SUN	SCE	
GENESI_2_STG	27-Nov-13	250.0	171.0	SUN	PGAE	
VICTOR_1_SOLAR1	06-Dec-13	17.5	12.0	SUN	SCE	
GLDTWN_6_COLUM3	10-Dec-13	10.0	6.8	SUN	SCE	
ETIWND_2_CHMPNE	20-Dec-13	1.0	0.7	SUN	SCE	
CHINO_2_JURUPA	20-Dec-13	1.5	1.0	SUN	SCE	
CONTRL_1_CASAD1	20-Dec-13	10.0	7.0	GEO THERMAL	PGAE	
CHINO_2_SASOLR	20-Dec-13	1.5	1.0	SUN	SCE	
DEVERS_1_SOLAR	24-Dec-13	18.5	12.7	SUN	SCE	
RSMCLR_6_SOLAR1	20-Dec-13	20.0	13.7	SUN	SCE	
RSMCLR_6_SOLAR2	20-Dec-13	20.0	13.7	SUN	SCE	
PEORIA_1_SOLAR	30-Dec-13	1.5	1.0	SUN	PGAE	
KNGBRG_1_KBSLR1	30-Dec-13	1.5	1.0	SUN	PGAE	
KNGBRG_1_KBSLR2	30-Dec-13	1.5	1.0	SUN	PGAE	
IVANPA_1_UNIT1	30-Dec-13	126.0	86.2	SUN	SCE	
IVANPA_1_UNIT2	30-Dec-13	133.0	90.9	SUN	SCE	
IVANPA_1_UNIT3	30-Dec-13	133.0	90.9	SUN	SCE	
VLCNTR_6_VCCLR1	30-Dec-13	2.5	1.7	SUN	SDGE	
VLCNTR_6_VCCLR2	30-Dec-13	5.0	3.4	SUN	SDGE	
CRELMN_6_RAMON1	30-Dec-13	2.0	1.4	SUN	SDGE	
CRELMN_6_RAMON2	31-Dec-13	5.0	3.4	SUN	SDGE	
MSOLAR_2_SOLAR1	01-Jan-14	165.0	112.8	SUN	SCE	
ESCND0_6_PL1X2	23-Jan-14	49.5	49.5	NATURAL GAS	SDGE	
LOCKFD_1_BEARCK	05-Feb-14	1.5	1.0	SUN	PGAE	
COGNAT_1_UNIT	12-Feb-14	49.5	30.2	BIOMASS	PGAE	
JAYNE_6_WLSLR	18-Feb-14	18.0	12.3	SUN	PGAE	
IVSLRP_2_SOLAR1	04-Mar-14	200.0	136.8	SUN	SDGE	
PIT1_6_FRIVRA	05-Mar-14	1.5	1.0	SUN	PGAE	
MCARTH_6_FRIVRB	05-Mar-14	1.5	1.0	SUN	PGAE	
TMPLTN_2_SOLAR	06-Mar-14	1.5	1.0	SUN	PGAE	
OLDRIV_6_BIOGAS	10-Mar-14	2.0	1.2	BIOMASS	PGAE	
RIVRBK_1_LNDFIL	11-Mar-14	1.0	0.6	LANDFILL GAS	PGAE	
WIND PROJECT	3/13/2014 (COM)	138.0	26.3	Wind	SCE	
OTAY_6_LNDFL5	14-Mar-14	1.5	0.9	Land Fill Gas	SDGE	
OTAY_6_LNDFL6	14-Mar-14	1.5	0.9	Land Fill Gas	SDGE	
LOCKFD_1_KSOLAR	14-Mar-14	1.0	0.7	SUN	PGAE	
WIND PROJECT	3/17/2014 (COM)	90.0	17.1	Wind	SCE	
SOLAR PROJECT	4/17/2014 (COM)	72.0	49.2	SUN	SCE	
SOLAR PROJECT	4/17/2014 (COM)	103.5	70.8	SUN	SCE	
SOLAR PROJECT	4/18/2014 (COM)	195.3	133.6	SUN	SCE	
Total			4,859	3,555	ISO	
			3,010	1,997	SP26	
			1,849	1,558	NP26	

Note: COM means commercial operations for markets

Table 6

High Probability Generation Additions Expected (MW) from 4/23/2014 to 6/1/2014					
Project Name	Project Type	Estimated COD	NDC	NQC (est)	PTO
Solar Project	New	4/23/2014	1.5	1.0	SCE
Solar Project	New	4/23/2014	20.0	13.7	PG&E
Solar Project	New	4/27/2014	1.5	1.0	PG&E
Solar Project	New	4/30/2014	2.0	1.4	SCE
Solar Project	New	4/30/2014	2.0	1.4	SCE
Solar Project	New	4/30/2014	5.0	3.4	SCE
Solar Project	New	before 6/1/2014	20.0	13.7	PG&E
Solar Project	New	before 6/1/2014	20.0	13.7	PG&E
Solar Project	New	before 6/1/2014	6.5	4.4	SDG&E
Wind Project	New	before 6/1/2014	4.2	0.8	SCE
Solar Project	New	before 6/1/2014	1.5	1.0	PG&E
Solar Project	New	before 6/1/2014	1.3	0.9	PG&E
Solar Project	New	before 6/1/2014	25.0	17.1	PG&E
Land Fill Gas Project	New	before 6/1/2014	0.8	0.5	PG&E
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Solar Project	New	before 6/1/2014	1.3	0.9	PG&E
Biomass Project	New	before 6/1/2014	3.0	1.8	PG&E
Natural Gas Project	New	before 6/1/2014	4.3	4.3	PG&E
Natural Gas Project	New	before 6/1/2014	4.2	4.2	PG&E
Natural Gas Project	New	before 6/1/2014	4.3	4.3	PG&E
Solar Project	New	before 6/1/2014	1.5	1.0	SCE
Solar Project	New	before 6/1/2014	1.5	1.0	SCE
Solar Project	New	before 6/1/2014	1.5	1.0	SCE
Solar Project	New	before 6/1/2014	1.5	1.0	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Natural Gas Project	Conversion	before 6/1/2014	170.7	170.7	SCE
Total			425	338	ISO
			318	261	SP26
			107	77	NP26

Table 7

Total Expected Generation change (MW) from June 1, 2013 to June 1, 2014						
	from 6/1/2013 to 4/22/2014	from 6/1/2013 to 4/22/2014	As of 4/22/ 2014	from 4/23/2014 to 6/1/2014	for 2014 summer	for 2014 summer
	Additions COD	Retirements	Existing	High Probability Additions	Total Expected	Total Expected Change
ISO	3,555	(650)	53,612	338	53,950	3,243
SP26	1,997	0	26,178	261	26,439	2,258
NP26	1,558	(650)	27,434	77	27,511	985

This assessment uses all capacity available within the ISO balancing authority regardless of contractual arrangements to evaluate resource adequacy in order to understand how the system will respond under contingencies. Although some resources may not receive contracts under the resource adequacy program, and may contract with entities outside the ISO for scheduled short-term exports, these resources are still considered available to the ISO.

The NQC values for wind and solar are determined and annually adjusted based on actual output during peak hours over a three-year period. If the ISO balancing authority experiences extreme weather conditions beyond what is considered by the NQC calculation process, it is possible that not all of the capacity accounted for will be available because the unit ratings of combustion turbines and some other resources are impacted by high ambient temperatures.

Generation Unavailability

The estimated 1-in-2 generation outages during the 2014 summer peak demand periods for the ISO, SP26 and NP26 are 5,030 MW, 2,105 MW and 2,921 MW, respectively. The estimated 1-in-10 generation outages for the ISO, SP26 and NP26 are 6,478 MW, 3,406 MW and 4,126 MW, respectively (*Table 8*). The last three years of generation outages during the peak demand period were used to develop a range of outages for the probabilistic analysis and to determine the 1-in-2 and 1-in-10 outage levels for the deterministic analysis.

Table 8

Generation Outages for Summer 2014 (MW)			
	ISO	SP26	NP26
1-in-2	5,030	2,105	2,921
1-in-10	6,478	3,406	4,126

Hydrologic Conditions

The 2014 water year is one of the most severe droughts on record according to California Department of Water Resources. *Figure 5* shows the California snow water content as of April 29, 2014 and indicates that statewide snowpack was 15% of the April 1 average, 6% for the northern area, 21% for central area and 17% for southern area. April 1 is the date that snowpack is typically at its peak level.

The northern Sierra precipitation was at 62% of the average, and the southern San Joaquin was at 49% of the average (*Figure 6 and 7*). The forecasted median April-July runoff in the major Sierra river basins ranges from 9% on the Tule River to 48% for the Inflow to Shasta Lake. The comparison of water storage of major reservoirs in California, as of April 29, 2014, is 50% of capacity, 63% of average and 68% of 2013 level in *Table 9*. Although reservoir levels may increase between now and early summer, the outlook for additional precipitation and snowpack does not project improvement.

The ISO hydro generation in August from the 2014 Resource Adequacy Net Qualifying Capacity List is 7,666 MW, the lowest in the past 10 years. Hydro generation accounts for almost 14% on-peak power supply. The hydro derate for 2014 is estimated to be 1,370 MW for the normal scenario based on the PTO's estimation of hydro capacity during heat waves this summer. In addition, the ISO further reduced hydro capacity sourced by snow pack and precipitation by 10% and projected the hydro derate to be 1,669 MW to reflect the severe drought in this summer for the extreme deterministic scenario and for the probabilistic analyses.

Only 44 MW NQC of hydro generation is located in San Diego and Orange Counties. Consequently, low hydro conditions will not impact local resource adequacy issues in the San Diego and Orange County areas related to the retirement of SONGS. According to *2014 LOCAL CAPACITY TECHNICAL ANALYSIS*, the total RA requirement for LA Basin area is 10,430 MW; there are 11,789 MW resources available to meet the demand.

Table 9
California Daily Major Reservoir Storage Summary

Report generated: 04/29/2014 13:02							
Water Storage							
Reservoir Name	Capacity (AF)	Current Storage (AF)	Current % of Capacity	Historical Average Storage	Current % of Average	Storage - Year Ago This Date	Current % of 2013
TRINITY RIVER							
TRINITY LAKE	2,447,650	1,296,739	53%	2,013,443	64%	2,144,752	60%
SACRAMENTO RIVER							
SHASTA	4,552,000	2,409,395	53%	3,907,809	62%	3,815,354	63%
FEATHER RIVER							
OROVILLE	3,537,577	1,876,551	53%	2,864,870	66%	3,065,588	61%
STANISLAUS RIVER							
NEW MELONES	2,400,000	929,108	39%	1,505,597	62%	1,472,364	63%
TUOLUMNE RIVER							
DON PEDRO	2,030,000	1,075,543	53%	1,486,808	72%	1,470,210	73%
SAN LUIS CREEK							
SAN LUIS	2,041,000	952,999	47%	1,823,335	52%	1,125,741	85%
Total Storage	17,008,227	8,540,335	50%	13,601,862	63%	13,094,009	68%

<http://www.cdec.water.ca.gov/cgi-progs/reservoirs/RES>

Figure 5
California Snow Water Content, April 29, 2014

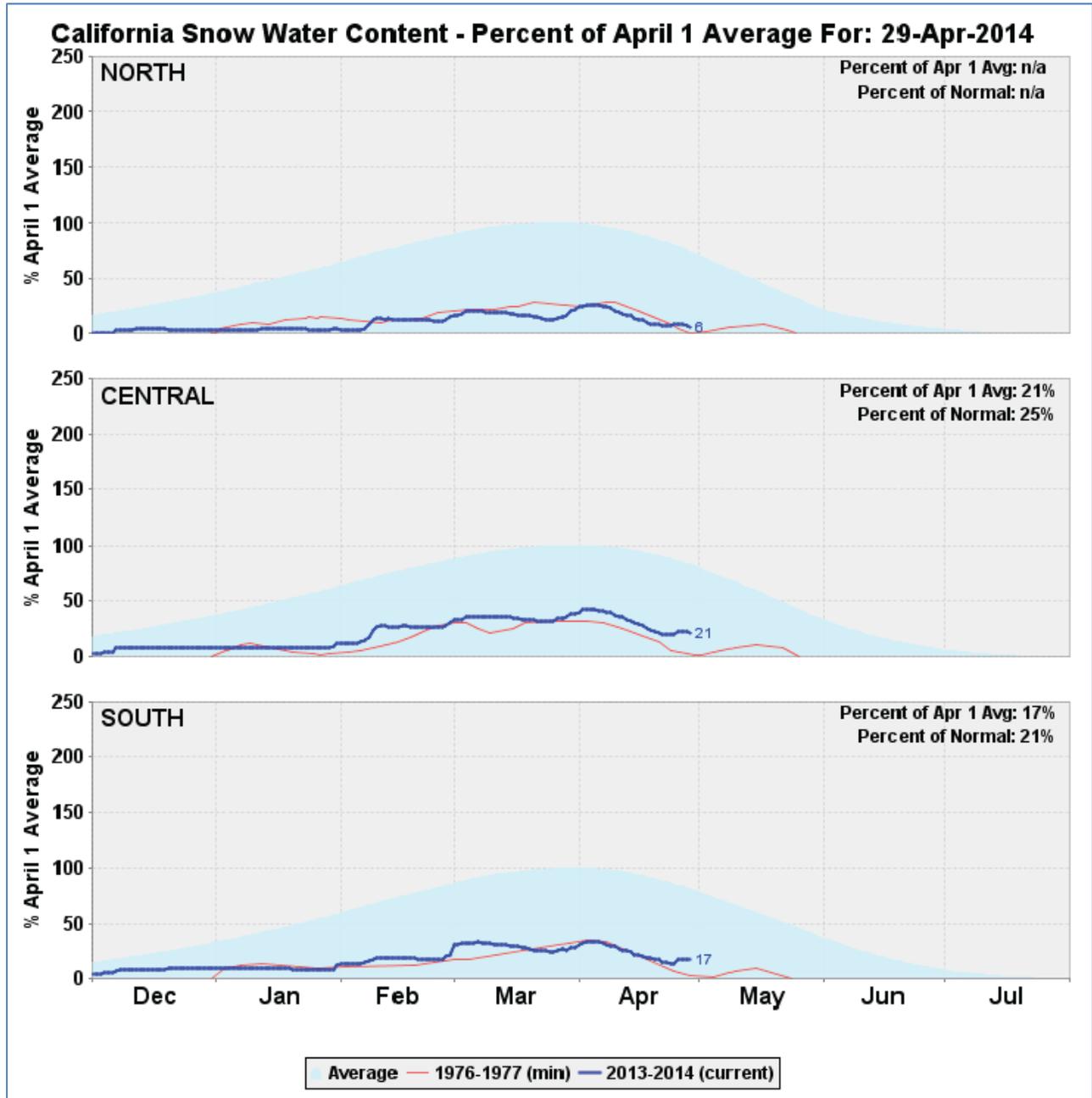


Figure 5 shows that the current snow water content is well below average in all areas.
 (Source: California Department of Water)

Figure 6

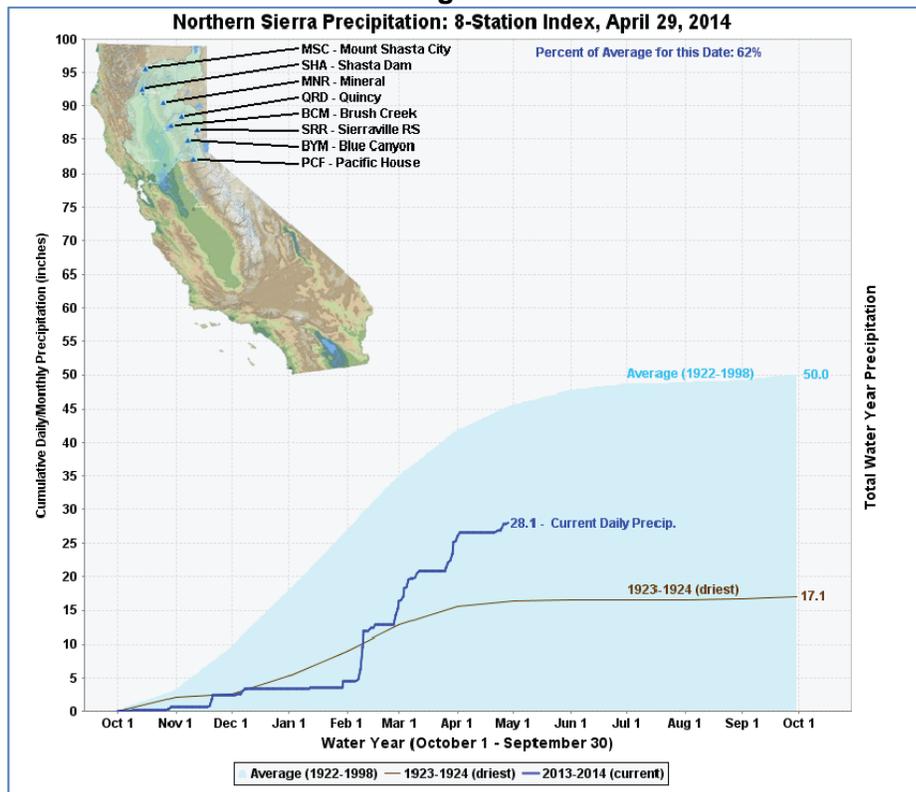
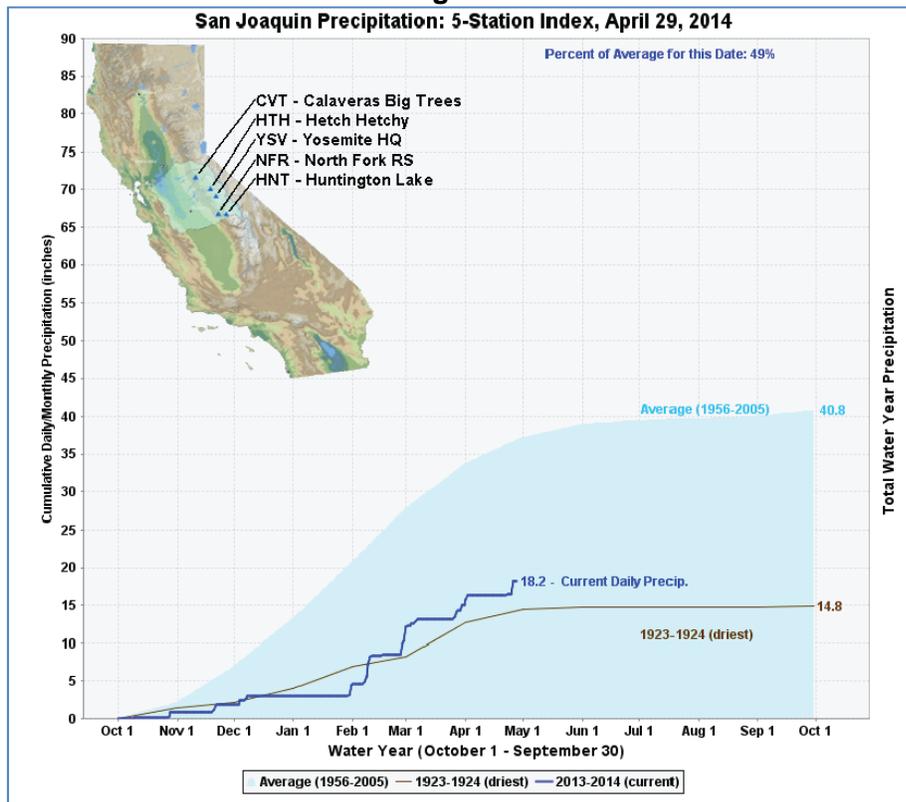


Figure 7



Source: California Department of Water Resources

Imports

Numerous factors contribute to the level of interchange between the ISO and other balancing authorities. Conditions for any given year and on any given day can affect any area ranging from just a local area to regional areas or even the entire Western Interconnection. These factors typically include market dynamics, demand within various areas, day-ahead forecasts accuracy, generation availability, transmission congestion, and hydro conditions. On any given day, the degree to which any one of these interrelated factors influence import levels can vary greatly.

Two types of contingencies may cause the system to need more than normal imports to meet peak demands. One type of contingency is a weather event that is forecasted in advance, or a forced outage that extends over multiple days that allow system operators to plan ahead and line up needed imports.

Another type of contingency is a real-time event that occurs in real-time operation after running the day-ahead and real-time markets, such as loss of a significant amount of generation or transmission, or a significantly under-forecasted peak demand. Under these circumstances, it may be too late to use the capabilities of other balancing authorities to deal with these types of contingencies.

It is beyond the scope of this report to model the complex dynamics that lead to a given import level on any given day or for any given set of contingencies. There is no single import amount that can be used in these analyses that can represent every scenario. Consequently, three levels of imports are developed for the deterministic and probabilistic analysis: high, moderate and low.

Table 10 for the 2014 assessment. Graphs of actual imports during summer 2011 to 2013 peak operating hours for the ISO system and the SP26 and NP26 zones are included in *Appendix E: 2011 – 2013 Summer Imports Summary Graphs*. The sum of SP26 and NP26 is not equal to ISO system because zonal analysis for ISO, SP26 and NP26 is on a non-coincidental basis.

Table 10

2014 Summer Outlook - Import Scenarios (MW)			
	ISO	SP26	NP26
High Net Interchange	11,000	11,300	3,000
Moderate Net Interchange	9,000	9,200	2,100
Low Net Interchange	8,500	8,800	1,300

Demand response and interruptible load programs

Table 11 shows demand response and interruptible load programs for summer 2014 based on resource adequacy criteria for the month August. Demand response and interruptible load programs reduce end-user loads in response to a high price, a financial incentive, an environmental condition or a reliability issue. They play an important role to offset the need for more generation and provide system operators with additional flexibility in operating the system during periods of limited supply.

Demand response programs include critical peak pricing, demand bidding, capacity bidding, demand response contract, and peak day pricing programs whereas interruptible load programs include interruptible rates and direct control programs. Other non-Flex Alert customer voluntary curtailment amounts or non-dispatchable demand response is embedded in the load forecast as natural load reductions.

The Flex Alert program is an energy conservation program funded by the investor-owned utilities and authorized by the California Public Utilities Commission. The alerts advise consumers about how and when to conserve energy. In 2013, the ISO utilized the Flex Alerts program to help reduce loads during a number of high peak demand periods. The Flex Alert program continues to be a vital tool for the ISO during periods of high peak demand to maintain system reliability, using them as a signal that both voluntary and non-voluntary demand side resources are needed.

Table 11

Demand Response and Interruptible Load for Summer 2014 (based on summer amounts in August)			
	Demand Response	Interruptible Load	Total Program Amounts
ISO	627	1,439	2,066
SP26	262	1,079	1,341
NP26	365	360	725

Demand

The ISO 47,351 MW 1-in-2 peak demand forecast for 2014 is 1.4% above the 2013 weather normalized peak demand of 46,705 MW. The increase represents a modest economic recovery over 2013 based on the economic base case forecast from Moody's Analytics.

The ISO uses Itron's MetrixND to develop the ISO, SP26 and NP26 regression load forecast models, which produce the peak load forecasts. The inputs to the models are historical peak loads, calendar information, economic and demographic data, and weather data. The weather data comes from 24 weather stations located throughout the large population centers within the ISO balancing authority. Weather data used in the model includes maximum, minimum and average temperatures, cooling degree days, heat index, relative humidity, solar radiation indexes, as well as a 631 index.

A cooling degree day is the average of a day's high and low subtracting 65. The heat index combines air temperature and relative humidity to determine the human-perceived equivalent temperature. The 631 index is a weighted average of a weather variable calculated as 60% of a given day, 30% of prior day and 10% of two days prior. The historical load data used was from January 1, 2003 through December 31, 2013.

Peak load data is based on 60-minute average peak demands. Water delivery pump loads were not included in the forecast models as they do not react to weather conditions in a similar fashion and are subject to interruption. Pump load is added back into the forecast based on a range of typical pump loads during summer peak conditions.

The forecast process involves developing seven different weather scenarios for each year of weather history so that each historical year has a scenario that starts on each of the seven days of the week. The model results for forecasting peak demand, particularly the highest of the peak load days, are significantly improved using parameters such as humidity that were not available for most stations prior to 1995. Consequently, 1995 through 2013 historical weather was used, which produces 133 weather scenarios. The scenarios are used to develop a range of load forecasts for the probability analysis using a random number generation process. This distribution is used in developing the 1-in-2, 1-in-10, and other peak demand forecasts.

There are three main models representing three distinct areas — the ISO, SP26 and NP26. Other models that forecast various sub-regions have similar weather characteristics. Each time a new forecast is made, the models are updated by adding in the latest historical load, weather and operational data. The models also use historical and forecasts of gross domestic product and population as independent inputs for growth trends and for base load levels. Furthermore, the models use gross domestic product as an indicator of weather driven cooling load levels.

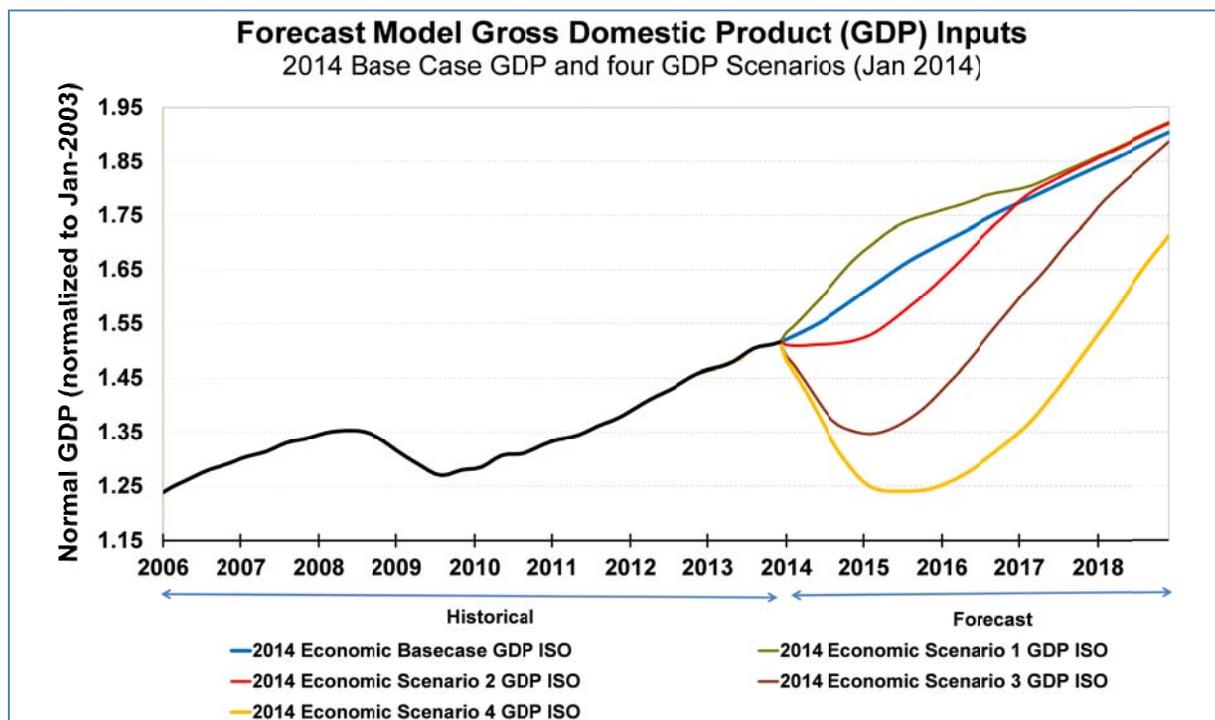
A base case forecast model is developed using baseline economic forecast data. The models are then trained with these new data. Five load forecast scenarios are developed using five economic scenario forecasts representing different outlooks of how the economy will perform based on different assumptions such as consumer confidence and household spending, labor markets and credit conditions. The ISO uses gross domestic product for the metropolitan statistical areas within the ISO developed by Moody's as the economic indicator for the models.

Figure 8 shows the historical and five gross domestic product forecasts that represent five different projections for how the current economics will play out. It is more difficult to accurately forecast future gross domestic product during the uncertain economic conditions California is experiencing. While officially the United States no longer in a recession, the economy has a potential to experience a new downturn as shown in Moody's more pessimistic scenario forecasts.

The baseline forecast is the median scenario wherein there is a 50% probability that the economy will perform better and a 50% probability that the economy will perform worse. The baseline and the four additional scenarios were all developed by Moody's.

- Scenario 1 is a stronger recovery scenario in which the economy rebounds. It is designed so that there is a 10% probability that the economy will perform better than this scenario, broadly speaking, and a 90% probability that it will perform worse.
- Scenario 2 is a weaker recovery scenario in which a second, relatively mild, downturn develops. It is designed so that there is a 75% probability that economic conditions will be better than this scenario, broadly speaking, and a 25% probability that conditions will be worse.
- Scenario 3 is a more severe second recession scenario in which a more severe second downturn develops. It is designed so that there is a 90% probability that the economy will perform better than this scenario, broadly speaking, and a 10% probability that it will perform worse.
- Scenario 4 is a very severe second recession scenario, it is designed so that there is a 96% probability that the economy will perform better than this scenario, broadly speaking, and a 4% probability that it will perform worse.

Figure 8



Source: Macroeconomic Outlook Alternative Scenarios – Jan 2014

Figure 8 shows that under the most likely scenario (base case) the economy will experience a modest recovery this year.

In Figure 8, scenario 1 is more optimistic than the base case forecast while scenarios 2 through 4 are progressively more pessimistic. The range of divergence between the various scenarios began Dec 31, 2013.

It is important to note that these forecasts are based on the Moody's gross domestic product forecasts released in December 2013. The gross domestic product forecasts are updated monthly and will change as the economic conditions evolves over the months ahead and new information becomes available. Currently, the gross domestic product data reflects actual historical data through 2012 (January 2013 and later historical data are estimates of actual GDP). Consequently, this forecast is based on data available at that time. Figure 9 shows a comparison of Moody's 2013 GDP forecast to their 2014 GDP forecast. Moody's 2014 forecast is a more conservative economic recovery forecast as compared to their 2013 economic base case forecast where the forecast for August 2014 GDP decreased 4% from 2013 to 2014.

Figure 10 shows ISO 1-in-2 peak demand forecasts based on the five economic scenarios from Moody's. The 2014 base case peak demand forecast and the scenario 1 forecasts by area are provided in Table 12 and Table 13, respectively. The 2014 forecasted 5.4% increase over the ISO 2013 below normal weather peak demand represents a moderate level of economic recovery over 2013 assuming normal weather for 2014. The details of scenarios 2 through 4 load forecasts are not presented in this report as the operating risks associated with these lower load forecasts are of lesser concern than the operating risks associated with the higher loads related to the base case and scenario 1 forecasts.

Figure 9

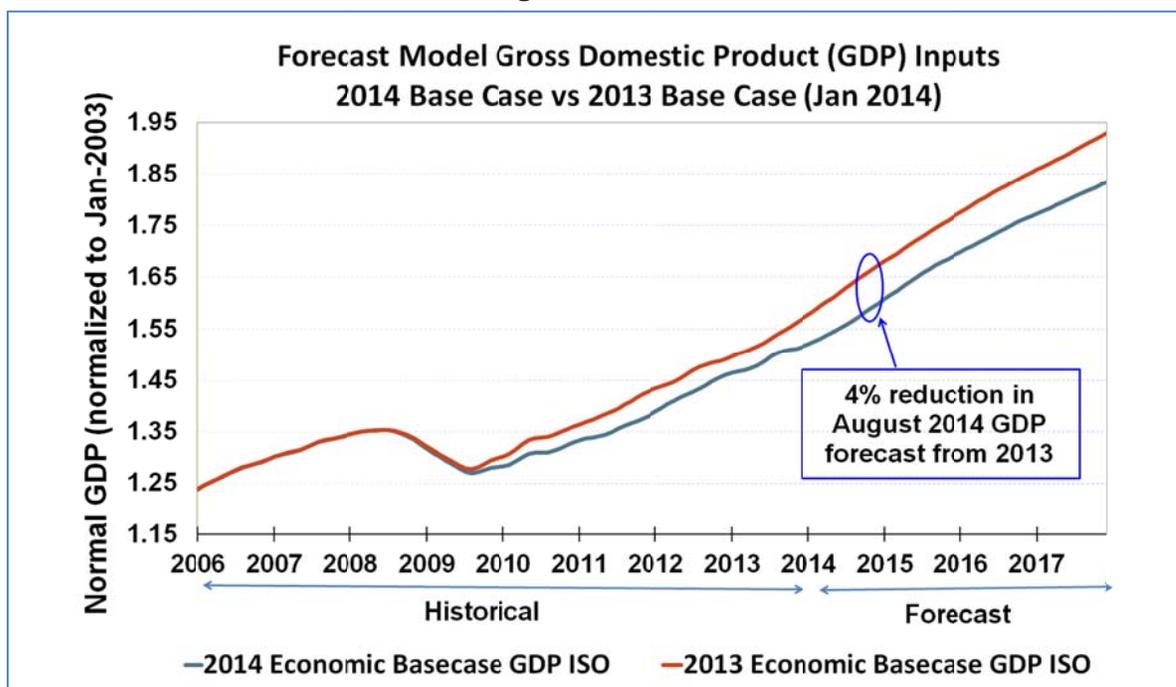


Figure 9 shows the difference between 2013 Economic base case GDP ISO and 2014 Economic base case GDP ISO.

Figure 10

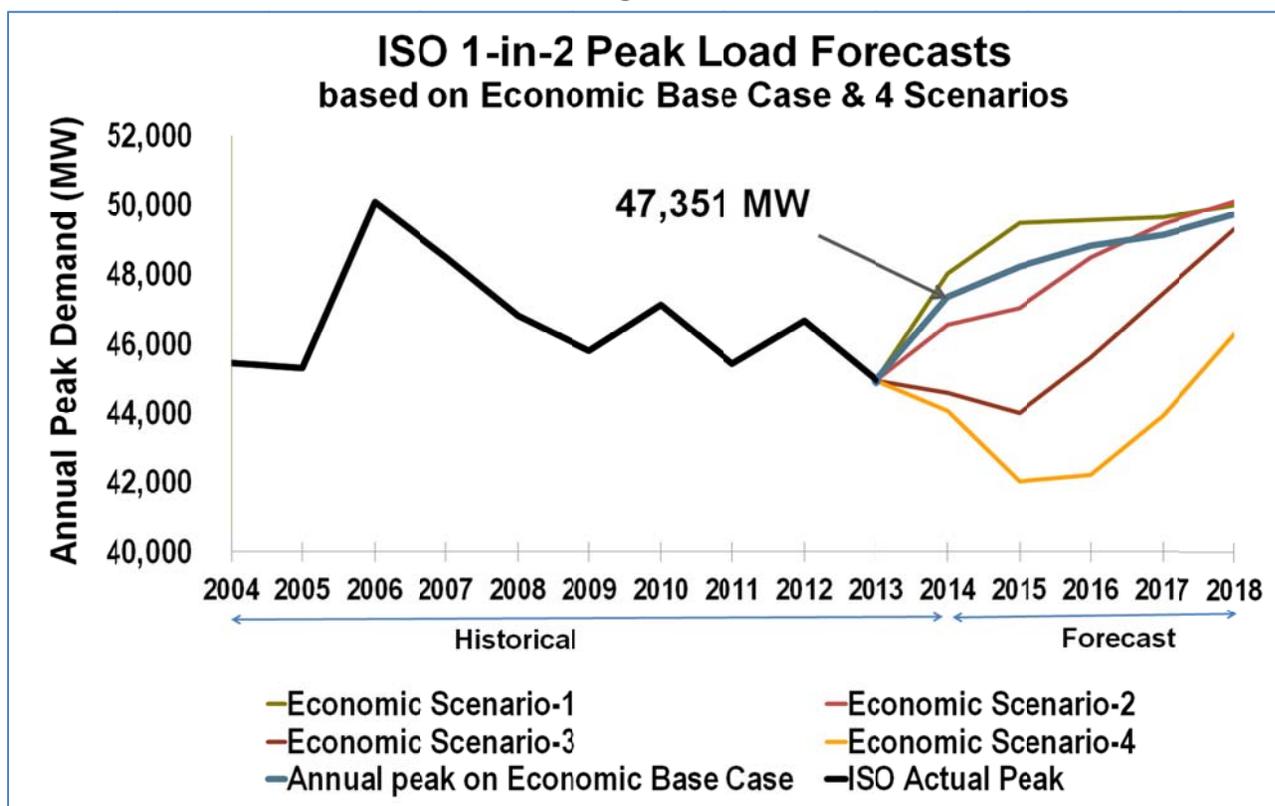


Figure 10 shows that as the economy improves in 2014 based on base case Scenario (see Figure 8) the ISO annual peak demand will increase in close parallel with base case.

Table 12

2014 Peak Demand Forecast vs. 2013 Actual Peak Demand					
2014 Peak Demand Forecast based on 2014 economic base case					
	Probability	Percentile	2014 Forecast	2013 Actual	% Change
ISO	1-in-2	50 th	47,351	44,941	5.4%
SP26	1-in-2	50 th	26,994	27,058	-0.2%
NP26	1-in-2	50 th	21,452	20,928	2.5%

Table 13 shows the peak demand forecasts associated with the economic scenario 1 forecast. While Moody's indicates the probability of this scenario is less than the base case, it is worth showing due to its potential impact on system reliability.

Table 13

2014 Peak Demand Forecast vs. 2013 Actual Peak Demand					
2014 Peak Demand Forecast based on 2014 economic scenario 1					
	Probability	Percentile	2014 Forecast	2013 Actual	% Change
ISO	1-in-2	50 th	48,402	44,941	7.7%
SP26	1-in-2	50 th	27,660	27,058	2.2%
NP26	1-in-2	50 th	21,591	20,928	3.2%

Table 14 and Table 15 provided a comparison of 1-in-2, 1-in-10 and 1-in-20 probability peak demand forecasts based on the 2013 economic base case and the 2014 economic scenario 1, using the 2012 peak demand forecasts from the 2013 economic base case as a reference point.

Table 14

2014 Peak Demand Forecast vs. 2013 Peak Demand Forecast					
2014 Peak Demand Forecast based on 2014 economic base case					
2013 Peak Demand Forecast based on 2013 economic base case					
	Probability	Percentile	2014 Forecast	2013 Forecast	% Change
ISO	1-in-2	50 th	47,351	47,413	-0.1%
	1-in-10	90 th	49,601	49,168	0.9%
	1-in-20	95 th	50,482	50,475	0.0%
SP26	1-in-2	50 th	26,994	27,253	-0.9%
	1-in-10	90 th	28,522	29,519	-3.4%
	1-in-20	95 th	29,338	30,067	-2.4%
NP26	1-in-2	50 th	21,452	21,328	0.6%
	1-in-10	90 th	22,377	22,290	0.4%
	1-in-20	95 th	23,213	23,231	-0.1%

Table 15

2014 Peak Demand Forecasts					
Economic Base Case & Optimistic Economic Scenario					
	Probability	Forecast Percentile	Base Case Forecast	Optimistic Scenario Forecast	Optimistic Scenario Increase
ISO	1-in-2	50 th	47,351	48,402	2.2%
	1-in-10	90 th	49,601	50,575	2.0%
	1-in-20	95 th	50,482	52,471	3.9%
SP26	1-in-2	50 th	26,994	27,660	2.5%
	1-in-10	90 th	28,522	30,016	5.2%
	1-in-20	95 th	29,338	30,591	4.3%
NP26	1-in-2	50 th	21,452	21,591	0.6%
	1-in-10	90 th	22,377	22,595	1.0%
	1-in-20	95 th	23,213	23,472	1.1%

Transmission

The WECC sets the operating transfer capability limits on transmission paths on a seasonal basis. *Figure 11* shows the main transmission paths for California ISO. The critical transmission paths are Path 66 – California-Oregon Intertie (COI), Path 65 – Pacific Direct Current Intertie (PDCI), Path 15 – Midway-Los Banos, and Path 26 – Midway-Vincent. The Southern California Import Transmission (SCIT) is composed of five separate paths: Path 65 – PDCI, Path 26 – Midway-Vincent, Path 27 – Intermountain Power Project DC (IPP DC), Path 46 – West-of-River, and North-of-Lugo. The COI, PDCI and SCIT operating transfer capabilities govern import levels into the ISO balancing authority. Path 45 defines import capability into SDG&E from Comision Federal de Electricidad in Mexico. Path 15 delineates operating transfer capability of the flow within PG&E while the Path 26 defines operating transfer capability on the Midway-Vincent lines between SCE and PG&E areas.

The ISO annually performs a seasonal transmission operations assessment using a variety of system operation scenarios. The scenarios include steady-state power flow analysis, time-domain transient stability analysis, post-transient analysis, and PV voltage stability analysis. The Intertie (COI) Operating Transfer Capability and the Southern California Import Transmission (SCIT) will not operate above its thermal limit for 2014 summer under normal operating condition. Power supply in Fresno area will be improved with completeness of reconductoring project of Panoche-Kearney 230 kV line during this summer. The Humboldt area remains limited by potential voltage stability. The seasonal study indicated that the transmission paths limits will not be exceeded under normal operation scenario during 2014 summer and no lines or equipment will operate above their normal thermal ratings.

Figure 11

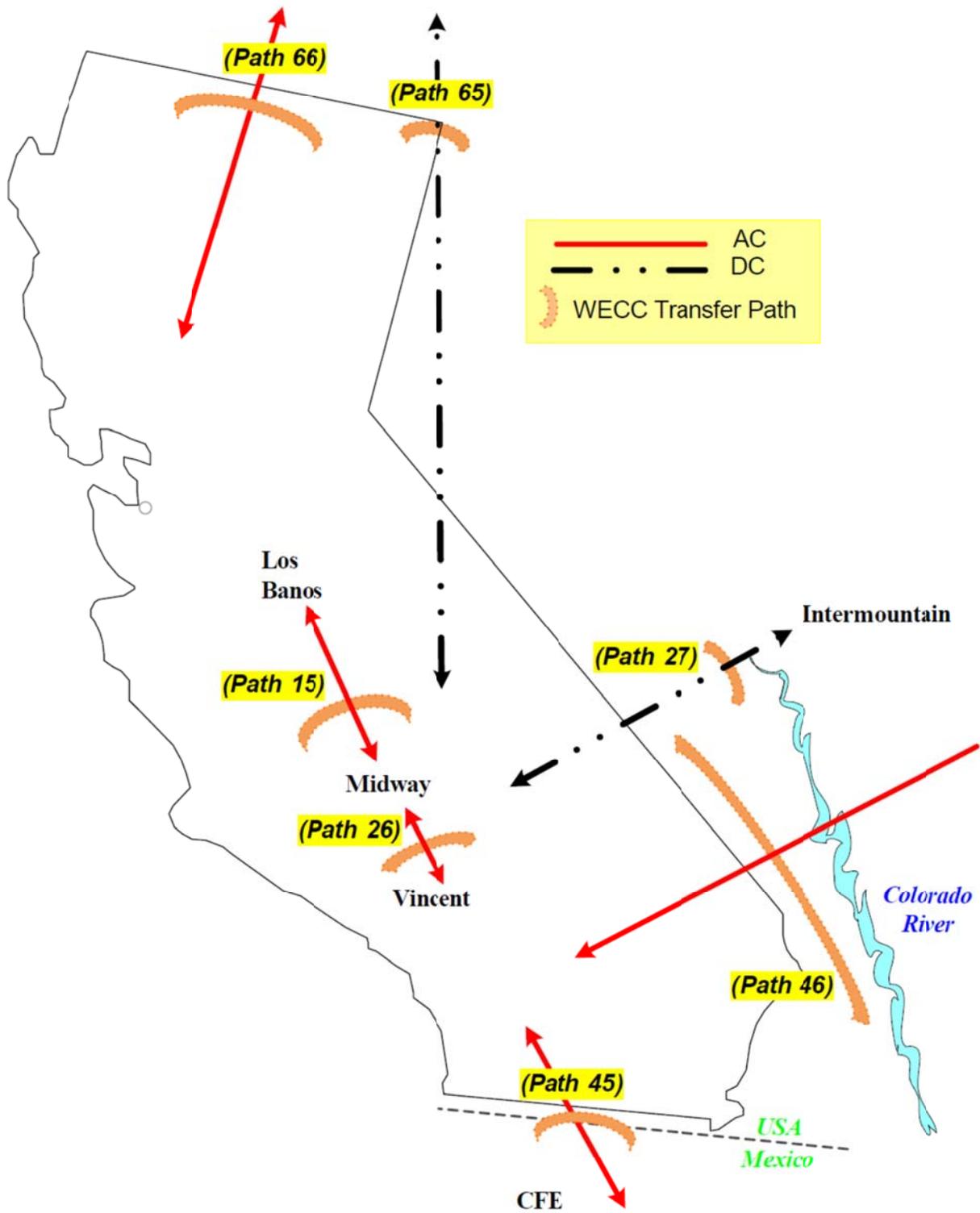


Figure 11 shows the main transmission paths for California ISO

System and zonal supply and demand deterministic analysis

Table 16 is the supply and demand outlook for the 2014 summer from a planning perspective. This table shows the planning reserves based on the 1-in-2 peak demand forecasts prior to accounting for any generation outages or transmission curtailments. The system and zonal planning reserve margins are robust due to generation additions and the economic downturn's continued impact on electric loads. The generation shown is based on current generation in service along with the generation expected to go on line and retire prior to summer 2014. The import amounts are based on the high, moderate and low import levels from Table 10.

Table 16
Planning Reserve Margins

Summer 2014 Supply & Demand Outlook (Planning Reserve Margins)			
Resource Adequacy Planning Conventions	ISO	SP26	NP26
Existing Generation	53,612	26,179	27,434
Retirement	0	0	0
High Probability Addition	337	260	77
Hydro Derate (below NQC)	(1,370)	(281)	(1,089)
Net Interchange (Moderate)	9,000	9,200	2,100
Total Net Supply (MW)	61,580	35,359	28,522
DR & Interruptible Programs	2,066	1,341	725
Demand (1-in-2 Summer Temperature)	47,351	26,994	21,452
Planning Reserve Margin	34.4%	36.0%	36.3%

Operating reserve margins transition from the planning perspective (Table 16) to a real-time perspective (Table 17) by adding in generation outages. Table 17 demonstrates how the import assumption impacts system and zonal operating reserve margins using 1-in-2 level generation outage and curtailment levels. The middle section of this table representing moderate imports corresponds to the same conditions as Table 17 but with 1-in-2 generation outage added.

Table 18 calculates system and zonal operating reserve margins under weather conditions that produce 1-in-10 peak demands, coincident with 1-in-10 level generation outage and curtailment. The scenarios portrayed in Table 18 rarely happen. The total ISO is highly dependent on imports to meet peak demand, especially during the summer high load periods.

Table 17

**Summer 2014 Loads and Resources Outlook
1-in-2 Demand, 1-in-2 Generation Outage**

Summer 2014 Outlook - High Imports			
<u>Resource Adequacy Conventions</u>	ISO	SP26	NP26
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
Hydro Derate (below NQC)	(1,370)	(281)	(1,089)
Outages (1-in-2 Generation)	(5,030)	(2,105)	(2,921)
Net Interchange (High)	11,000	11,300	3,000
Total Net Supply (MW)	58,550	35,353	26,501
DR & Interruptible Programs	2,066	1,341	725
Demand (1-in-2 Summer Temperature)	47,351	26,994	21,452
Operating Reserve Margin	28.0%	35.9%	26.9%

Summer 2014 Outlook - Moderate Imports			
<u>Resource Adequacy Conventions</u>	ISO	SP26	NP26
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
Hydro Derate (below NQC)	(1,370)	(281)	(1,089)
Outages (1-in-2 Generation)	(5,030)	(2,105)	(2,921)
Net Interchange (Moderate)	9,000	9,200	2,100
Total Net Supply (MW)	56,550	33,253	25,601
DR & Interruptible Programs	2,066	1,341	725
Demand (1-in-2 Summer Temperature)	47,351	26,994	21,452
Operating Reserve Margin	23.8%	28.2%	22.7%

Summer 2014 Outlook - Low Imports			
<u>Resource Adequacy Conventions</u>	ISO	SP26	NP26
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
Hydro Derate (below NQC)	(1,370)	(281)	(1,089)
Outages (1-in-2 Generation)	(5,030)	(2,105)	(2,921)
Net Interchange (Low)	8,500	8,800	1,300
Total Net Supply (MW)	56,050	32,853	24,801
DR & Interruptible Programs	2,066	1,341	725
Demand (1-in-2 Summer Temperature)	47,351	26,994	21,452
Operating Reserve Margin	22.7%	26.7%	19.0%

Table 18

**Summer 2014 Loads and Resources Outlook
1-in-10 Demand and 1-in-10 Generation Outage Scenarios**

Summer 2014 Outlook - High Imports			
<u>Resource Adequacy Conventions</u>	ISO	SP26	NP26
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
High Hydro Derate (below NQC)	(1,669)	(342)	(1,328)
High Outages (1-in-10 Generation)	(6,478)	(3,406)	(4,126)
Net Interchange (High)	11,000	11,300	3,000
Total Net Supply (MW)	56,803	33,991	25,057
DR & Interruptible Programs	2,066	1,341	725
High Demand (1-in-10 Summer Temperature)	49,601	28,522	22,377
Operating Reserve Margin	18.7%	23.9%	15.2%

Summer 2014 Outlook - Moderate Imports			
<u>Resource Adequacy Conventions</u>	ISO	SP26	NP26
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
High Hydro Derate (below NQC)	(1,669)	(342)	(1,328)
High Outages (1-in-10 Generation)	(6,478)	(3,406)	(4,126)
Net Interchange (Moderate)	9,000	9,200	2,100
Total Net Supply (MW)	54,803	31,891	24,157
DR & Interruptible Programs	2,066	1,341	725
High Demand (1-in-10 Summer Temperature)	49,601	28,522	22,377
Operating Reserve Margin	14.7%	16.5%	11.2%

Summer 2014 Outlook - Low Imports			
<u>Resource Adequacy Conventions</u>	ISO	SP26	NP26
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
High Hydro Derate (below NQC)	(1,669)	(342)	(1,328)
High Outages (1-in-10 Generation)	(6,478)	(3,406)	(4,126)
Net Interchange (Low)	8,500	8,800	1,300
Total Net Supply (MW)	54,303	31,491	23,357
DR & Interruptible Programs	2,066	1,341	725
High Demand (1-in-10 Summer Temperature)	49,601	28,522	22,377
Operating Reserve Margin	13.6%	15.1%	7.6%

Figures 12 and 13 provide graphical representations in percentage and MW, respectively, of the deterministic analysis results based on the inputs from Tables 17 and 18. Figure 12 shows that the operating reserve margins for ISO, SP26 and NP26 are projected to be well above the 3% firm load shedding threshold in the normal and extreme scenarios. While operating reserves are not necessarily procured on a zonal basis, the information portrayed in Figure 12 is useful for preparing for contingency events. Even with these projected operating reserve margins the ISO prepares contingency plans to deal with extreme events that could lead to firm load shedding.

These scenarios show the operating reserve margin after using all demand response programs. Analyzing the more extreme conditions frames the electric system challenges and identifies the magnitude of operating reserves during these conditions.

These Figures represent analyses of conditions for the ISO system as a whole, and for the SP26 and NP26 zones analyzed on a stand-alone, non-coincident basis. These results do not account for transmission constraints within the ISO system or within each zone. Based on this study methodology no firm load shedding would be needed under normal and extreme scenarios.

Figure 12

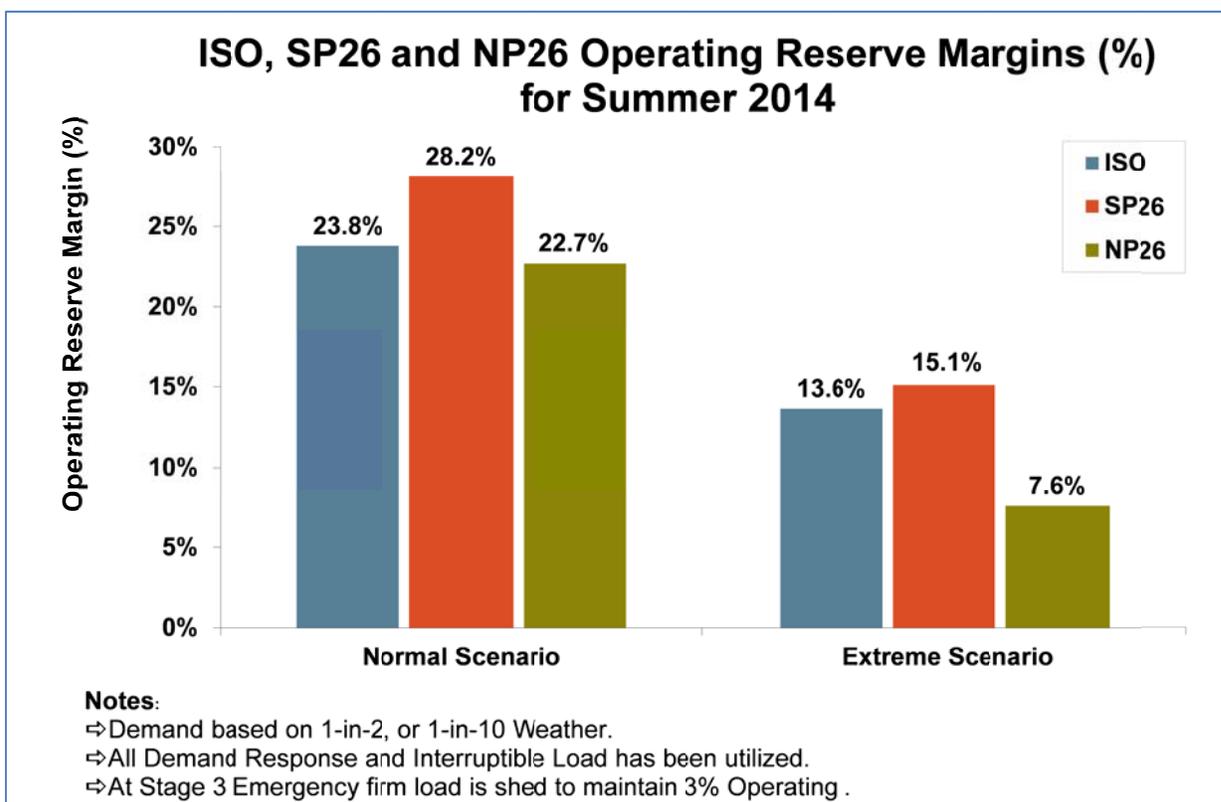


Figure 12 shows adequate operating reserve forecast margins under the normal and extreme scenarios. The operating reserve margins for ISO, SP26 and NP26 are projected to be above the 3% firm load shedding threshold in all scenarios.

Figure 13

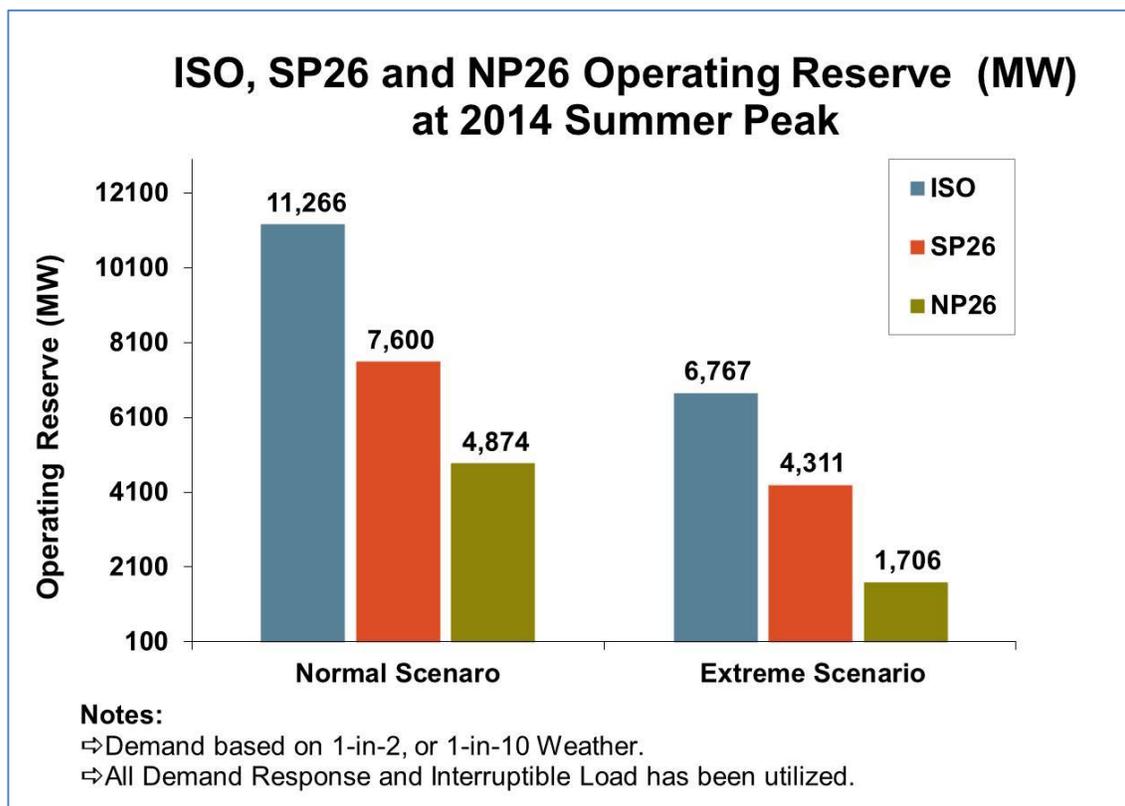


Figure 13 complements Figure 12 and reflects operating reserve margins in megawatts.

System and zonal supply and demand probabilistic analysis

A probabilistic model is used to understand the likelihood of experiencing operating conditions when operating reserves drop to 3% or lower, which is the point where firm load shedding would begin. Existing generation, known retirements, high probability additions, demand response and interruptible load programs are fixed single value inputs to the model and are shown in the previous deterministic tables such as *Table 18*.

The randomly generated forced and planned generation outages and curtailments are based on actual occurrences as shown in graphs in *Appendix C: 2011 – 2013 Summer Generation Outage Graphs*. They were used to develop a range of inputs of probable generation outage amounts.

The range of demand inputs were developed using the process described in the *Demand* section. After the model develops the range of operating reserves, the analysis focuses on the lower operating reserve margin range where the probability of having operating reserves margin drop to 3% or less is determined.

The moderate import scenario associated with different demand ranges were studied in this assessment. Low probability events, such as low imports over the full range of high demand conditions, were not considered under this assessment.

The expected probability of experiencing involuntary load curtailments because of low operating reserve margins in summer 2014 is 0.0% for ISO system, 0.0% for SP26 and 0.1% for NP26, assuming moderate imports, and the high hydro derate.

It is worth mentioning that these system and zonal results do not capture the local issues because supply and demand within a particular zone with local transmission outages are beyond the scope of this assessment.

Status of Generation Subject to Once Through Cooling Regulations

Table 19 shows the power plants that are subject to the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for power Plant Cooling. Of 17,792 MW OTC units affected by the regulations, 5,036 MW of these units are in compliance. The remaining 10,517 MW of generation will be required to repower or retire in by the end of 2020, many by the end of 2017. Compliance for Diablo Canyon is subject to a pending study by a Water Board Review Committee for Nuclear Fueled Power Plants.

Table 19

Generating Units Compliance with California Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling				
Plant (Unit)	Owner	Final Compliance Date	Capacity (MW)	PTO Area
Compliance Plan Yet to be Implemented (Natural Gas Fired)				
El Segundo Units 3	NRG	12/31/2015	335	SCE
El Segundo Units 4	NRG	12/31/2015	335	SCE
Encina Power Station Units 1-5	NRG	12/31/2017	946	SDG&E
Pittsburg Units 5 and 6	NRG	12/31/2017	629	PG&E
Moss Landing Units 1 and 2	Dynegy	12/31/2017	1,020	PG&E
Moss Landing Units 6 and 7	Dynegy	12/31/2017	1,500	PG&E
Huntington Beach Units 1-2	AES	12/31/2020	452	SCE
Redondo Beach Units 5-8	AES	12/31/2020	1,343	SCE
Alamitos Units 1-6	AES	12/31/2020	2,011	SCE
Mandalay Units 1 and 2	NRG	12/31/2020	430	SCE
Ormond Beach Units 1 and 2	NRG	12/31/2020	1,516	SCE
Total MW			10,517	
In Compliance				
Huntington Beach Units 3-4 ¹	AES	12/7/2012	452	SCE
Humboldt	PG&E	Sept. 2010	105	PG&E
Potrero Unit 3	GenOn	2/28/2011	206	PG&E
South Bay	Dynegy	1/1/2011	702	SDG&E
Contra Costa Units 6 and 7	NRG	5/1/2013	674	PG&E
San Onofre Unit 2 & 3	SCE	6/7/2013	2,246	SCE
Morro Bay Units 3 and 4	Dynegy	2/5/2014	650	PG&E
Total MW			5,035	
Compliance pending study by Water Board Review Committee for Nuclear Plants				
Diablo Canyon	PG&E	12/31/2024	2,240	PG&E
Total MW			2,240	
Total of all OTC Units			17,792	

Local Reliability Concerns due to SONGS Outage

The permanent retirement of the San Onofre Nuclear Generating Station was announced on June 7, 2013. This further validated the steps taken in 2012 to prepare the system for the summer of 2013 in anticipation of SONGS not returning to service. Those steps consisted of complete several transmission and voltage support enhancements in the LA Basin area.

- **Conversion of Huntington Beach Units 3 & 4 to Synchronous Condensers –** Converted these retired generating units to synchronous condensers provide voltage support in the vicinity of SONGS.
- **Installation of additional reactive support devices near SONGS -** SCE installed 80 MVAR capacitors at each of the Santiago and Johanna substations and two 80 MVAR capacitors at the Viejo substation.
- **Barre-Ellis reconfiguration -** SCE reconfigured the Barre - Ellis 220 kilovolt (kV) lines from the existing two circuits to four.

While additional approved mitigations are expected to begin coming into service for the summer of 2015, no additional transmission measures are available for the summer of 2014. With continued modest load growth, local reliability conditions in the south Orange and San Diego counties are likely to be marginally more challenging this summer compared to last.

If critical high-voltage transmission lines are out of service, due to wildfires or other conditions, deficient voltage levels may occur under peak load conditions that could trigger localized customer outages. Furthermore, the absence of SONGS results in potential overloading of local transmission lines under certain contingencies.

Until longer term mitigations are in place, southern Orange County and San Diego will remain susceptible to reliability concerns and will require close attention during summer operations – particularly during critical peak days and in the event of wildfires that could potentially force transmission lines out of service.

During these types of conditions, both demand response programs and Flex Alert conservation appeals will likely be used to lessen the strain on the grid.

Conclusion

The slowly improving economy, which resulted in moderate peak demand growth, combined with the availability of new power generation since June 2013 result in an overall adequate summer supply outlook for 2014 to meet a broad range of operating conditions. Although the risk of power supply shortages increases under extreme load conditions, coupled with more extreme unavailability of hydro generation, the net addition of 3,243 MW of generation reaching commercial operation since last summer and out-of-state imports will help to moderate these risks. As a whole, the main impact from the drought during the 2014 summer will be an increase in natural gas generation, which could result in an increase in energy prices and increased greenhouse gas emissions. However, the unusually dry conditions across the state do create a heightened risk of wildfires, which could impact the use of major transmission lines during periods of critical

summer peak demand. Thus, major wildfires could create grid reliability challenges over the summer, particularly in southern Orange County and San Diego where there is a risk of localized customer outages as a result of the retirement of SONGS.

The ISO annually trains its grid operators to be prepared for system events, and understand operating procedures and utility best practices. The ISO, in conjunction with the California Electric Training Advisory Committee, sponsors annual CETAC workshop to train grid operators. This year training subjects covered renewable resources for real time operations personnel, the WECC interchange authority failure backup procedure, system instability restoration, voltage mitigation and simulation drill, and mitigation system disturbance with communication and coordination.

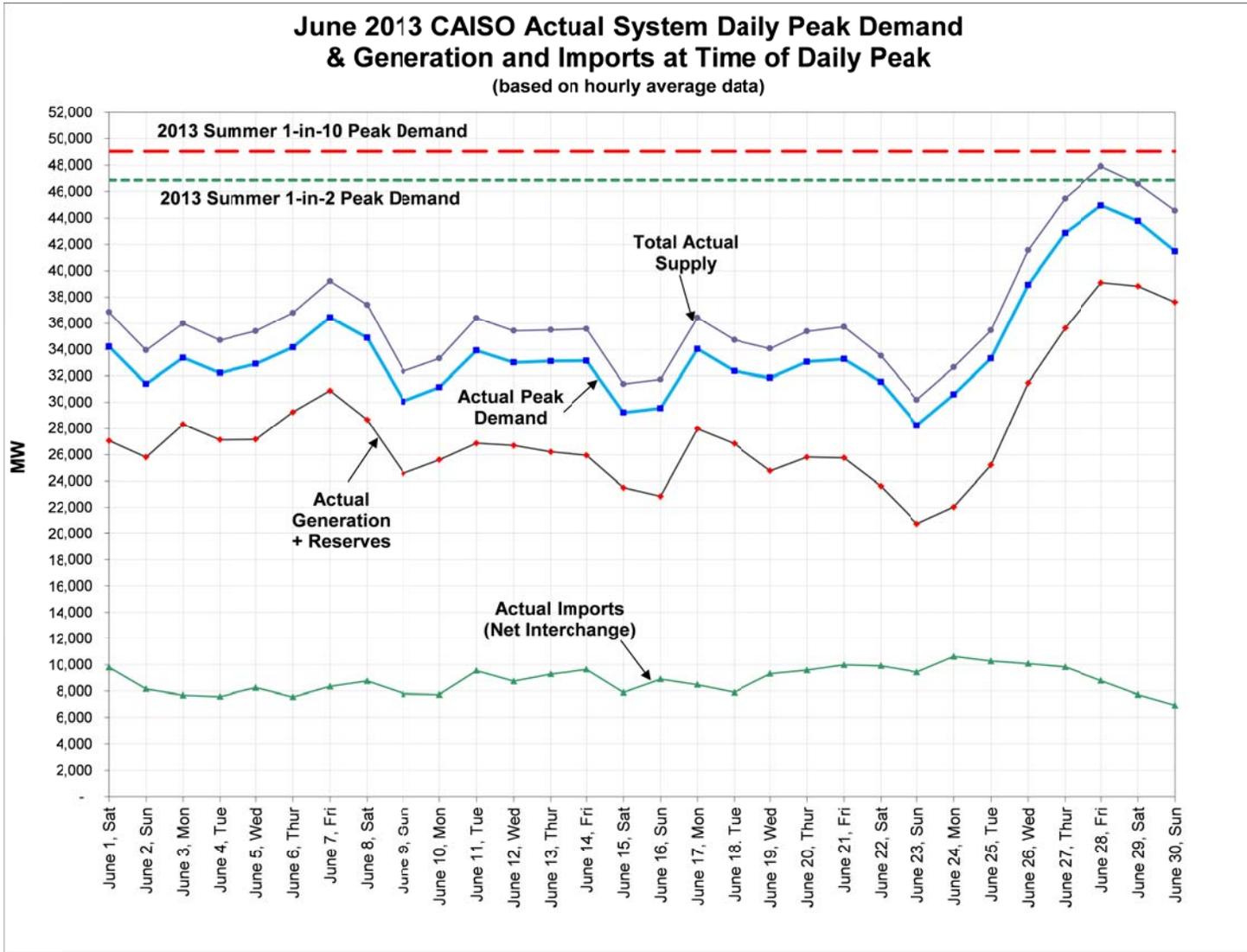
Furthermore, the ISO meets with WECC, Cal Fire, gas companies, and neighboring balancing authorities to discuss and coordinate on key areas. The ISO fosters ongoing relationships with these organizations to ensure reliable operation of the market and grid during normal and critical periods.

Significant amounts of new renewable generation has reached commercial operation and this trend is expected to continue as new renewable generation comes online to meet the state's 33% renewable portfolio standard. Sufficient flexible resources will need to be maintained on the system to be able to successfully integrate the increasing levels of renewables. This will be particularly challenging in light of the remaining 10,517 MW of natural gas fired generation capacity that is subject to once-through-cooling regulations, which requires this capacity to be retired, retrofitted with new cooling systems, or repowered by the end of 2020, some by the end of 2017. The ISO will continue to work closely with the relevant state agencies to evaluate the reliability impacts of complying with these and other environmental requirements to ensure that compliance is achieved in such a way that does not compromise electric grid reliability.

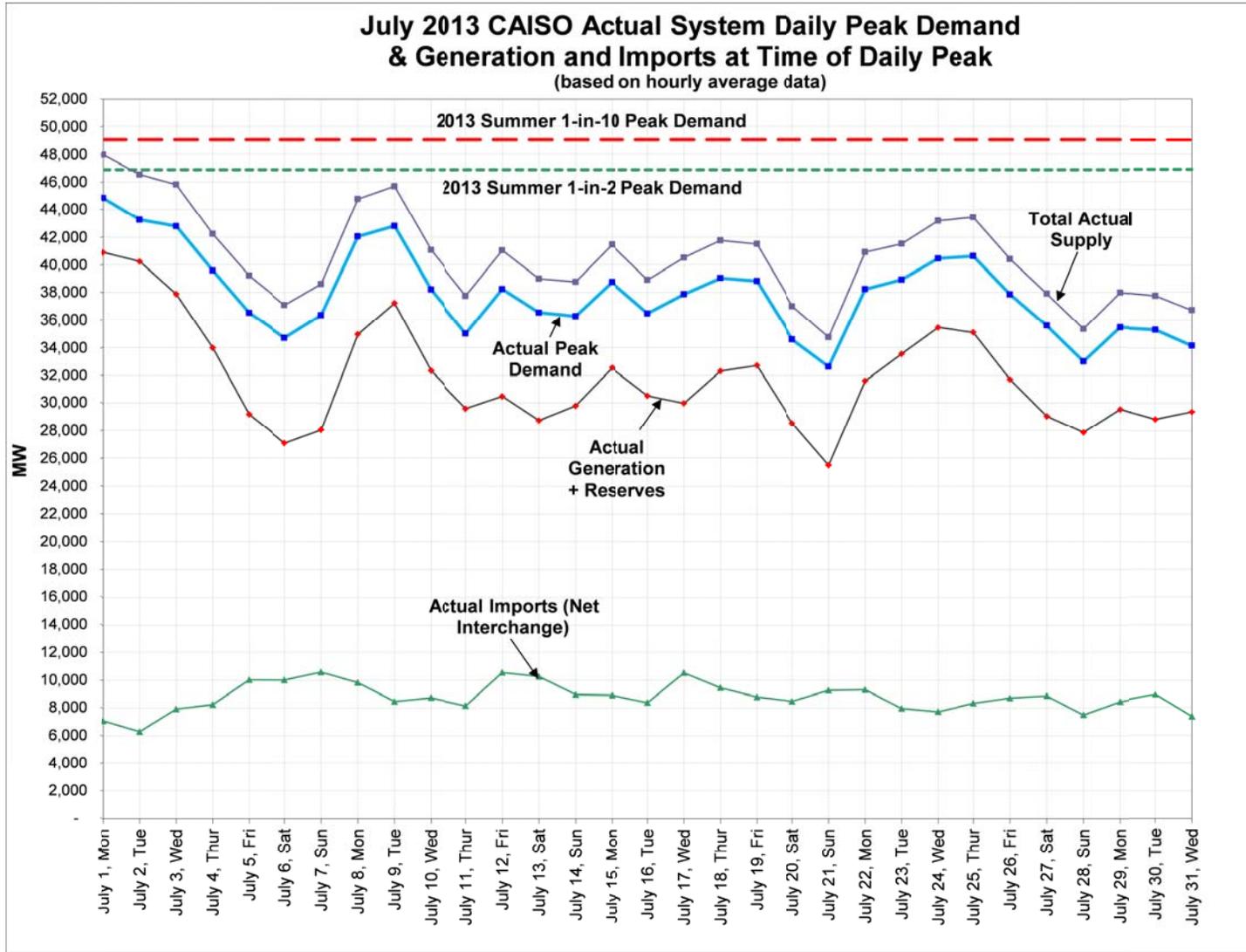
IV. APPENDICES

- A. 2013 Summer Peak Load Summary Graphs
- B. 2014 ISO NDC and RPS by Fuel Type
- C. 2011 – 2013 Summer Generation Outage Graphs
- D. 2011 – 2013 Summer Imports Summary Graphs
- E. 2014 ISO Summer On-Peak NQC Fuel Type

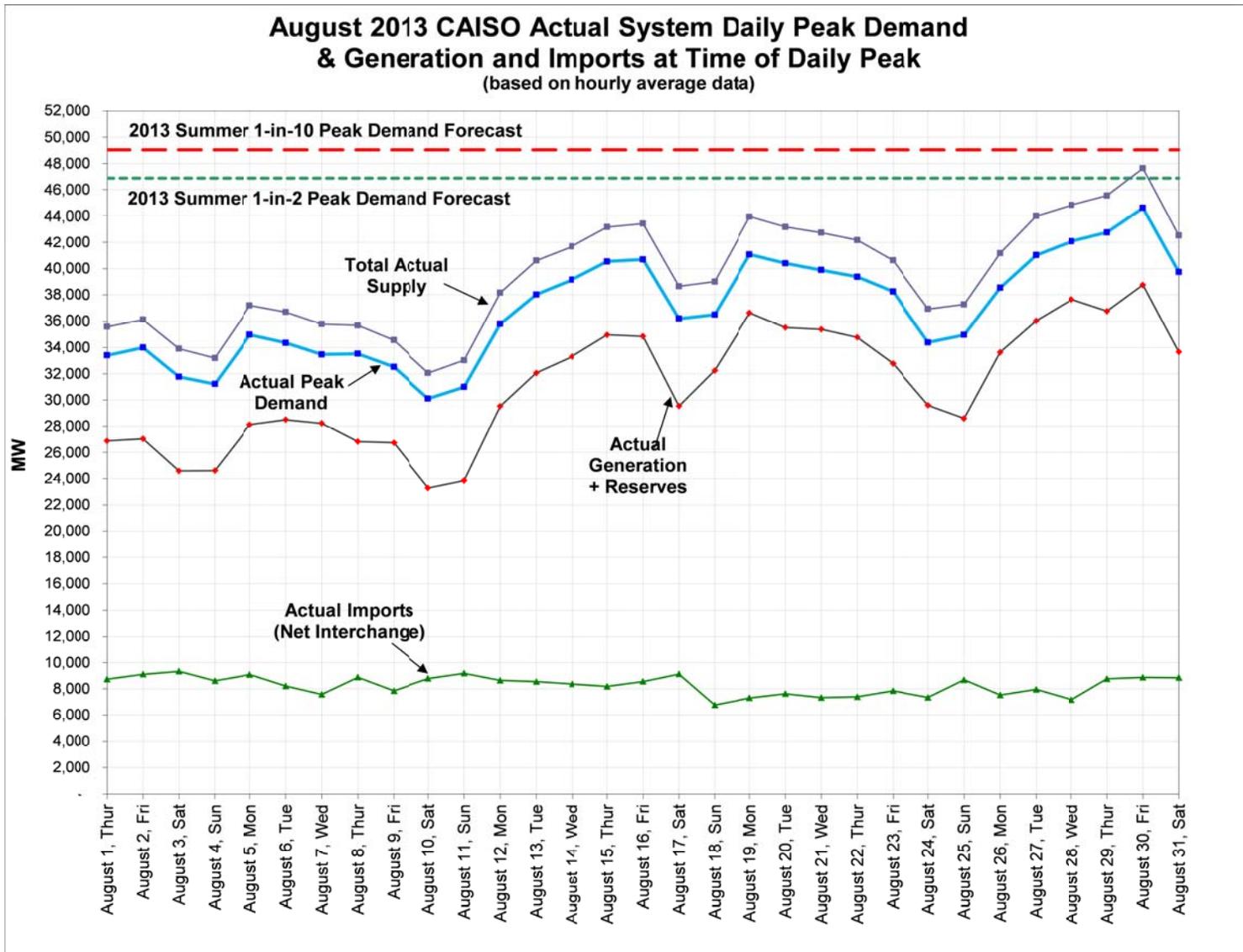
Appendix A: 2013 Summer Peak Load Summary Graphs



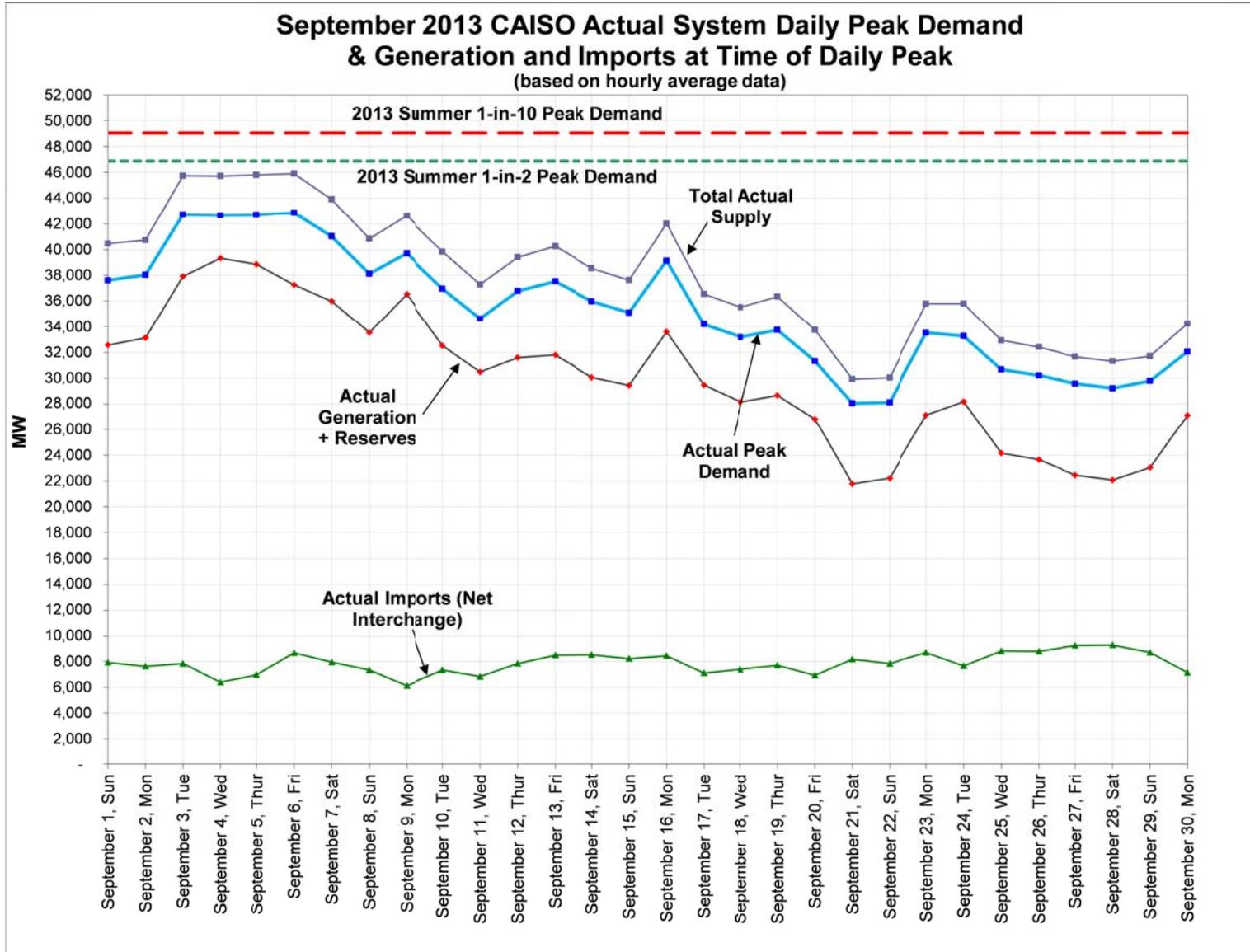
Appendix A – Continued



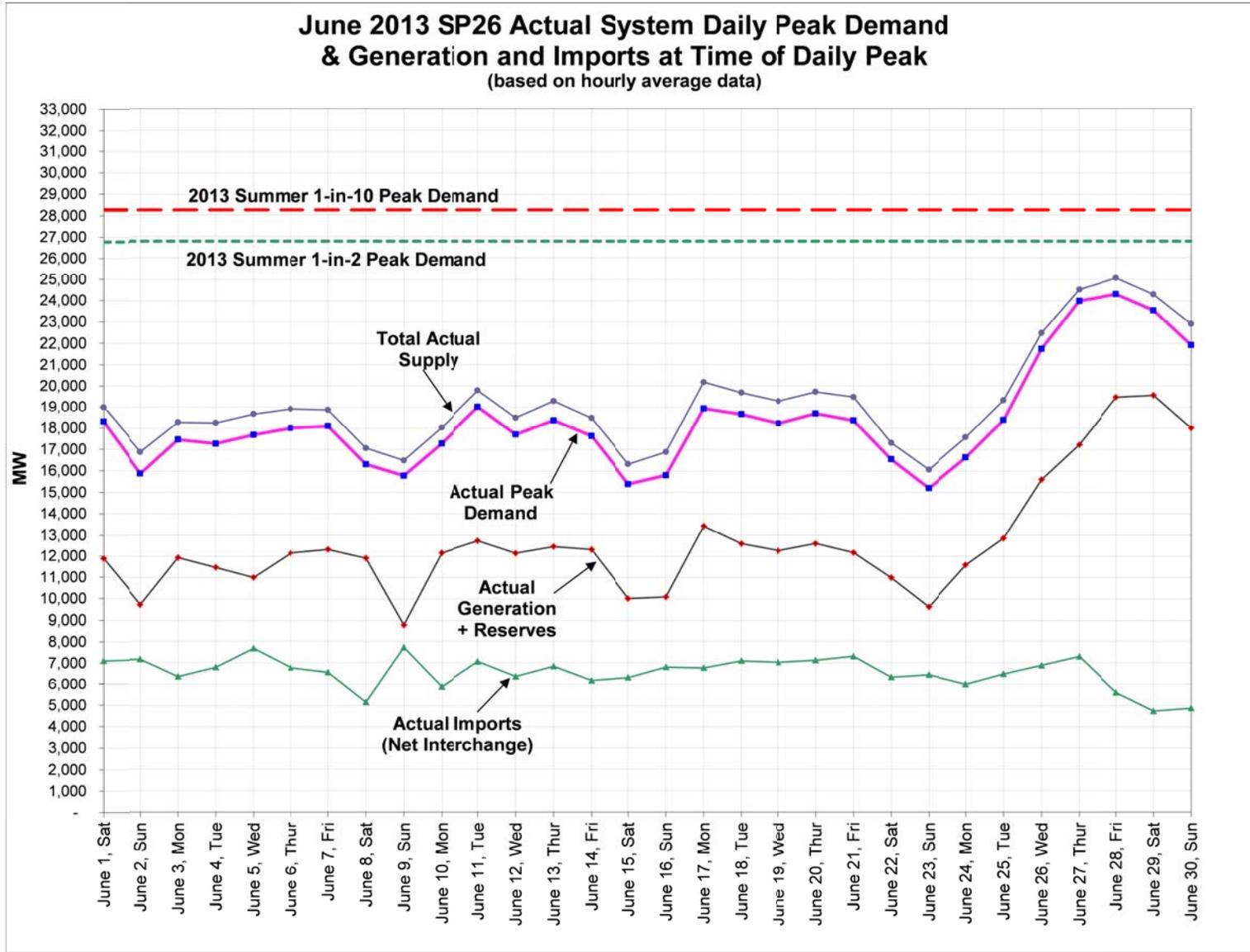
Appendix A – Continued



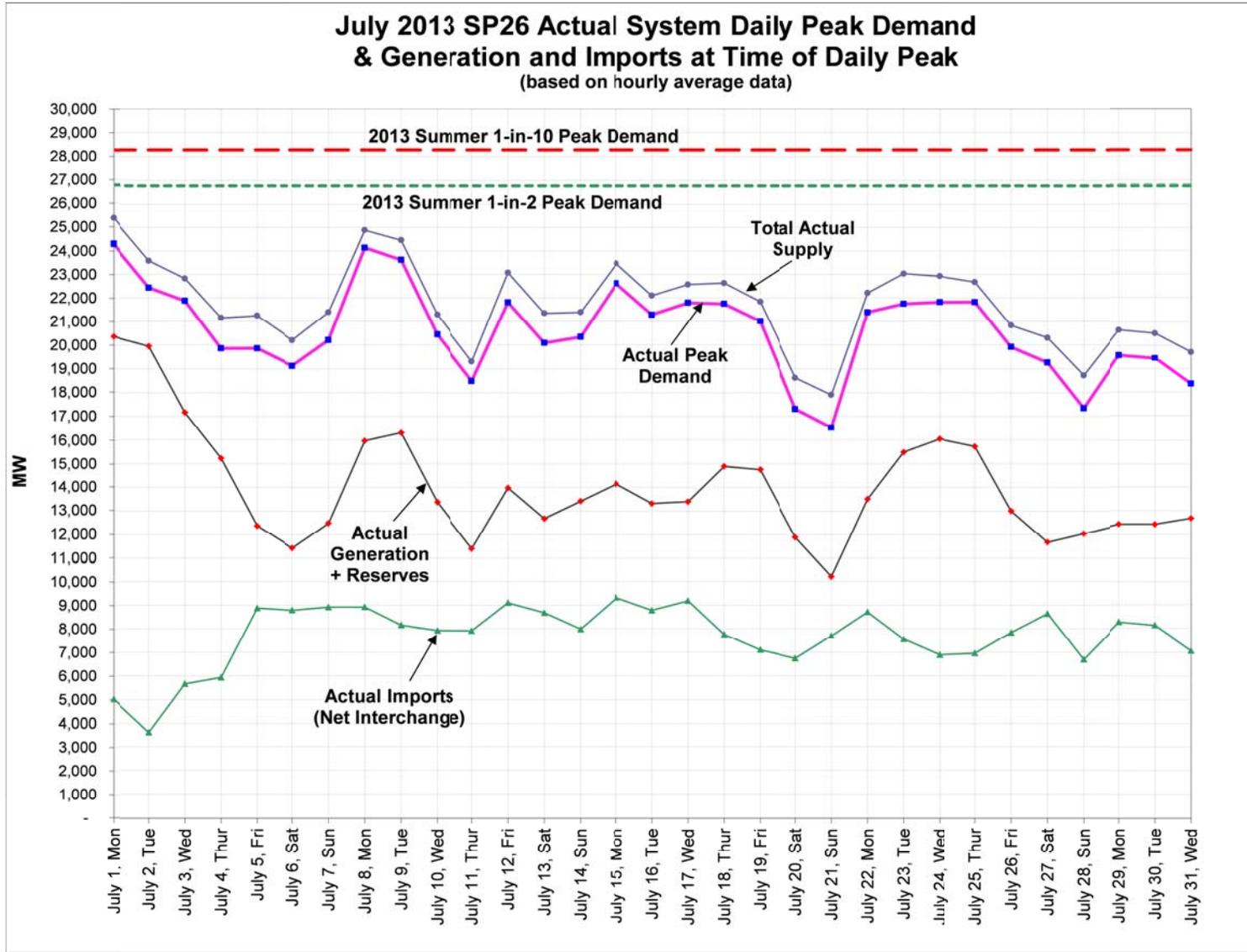
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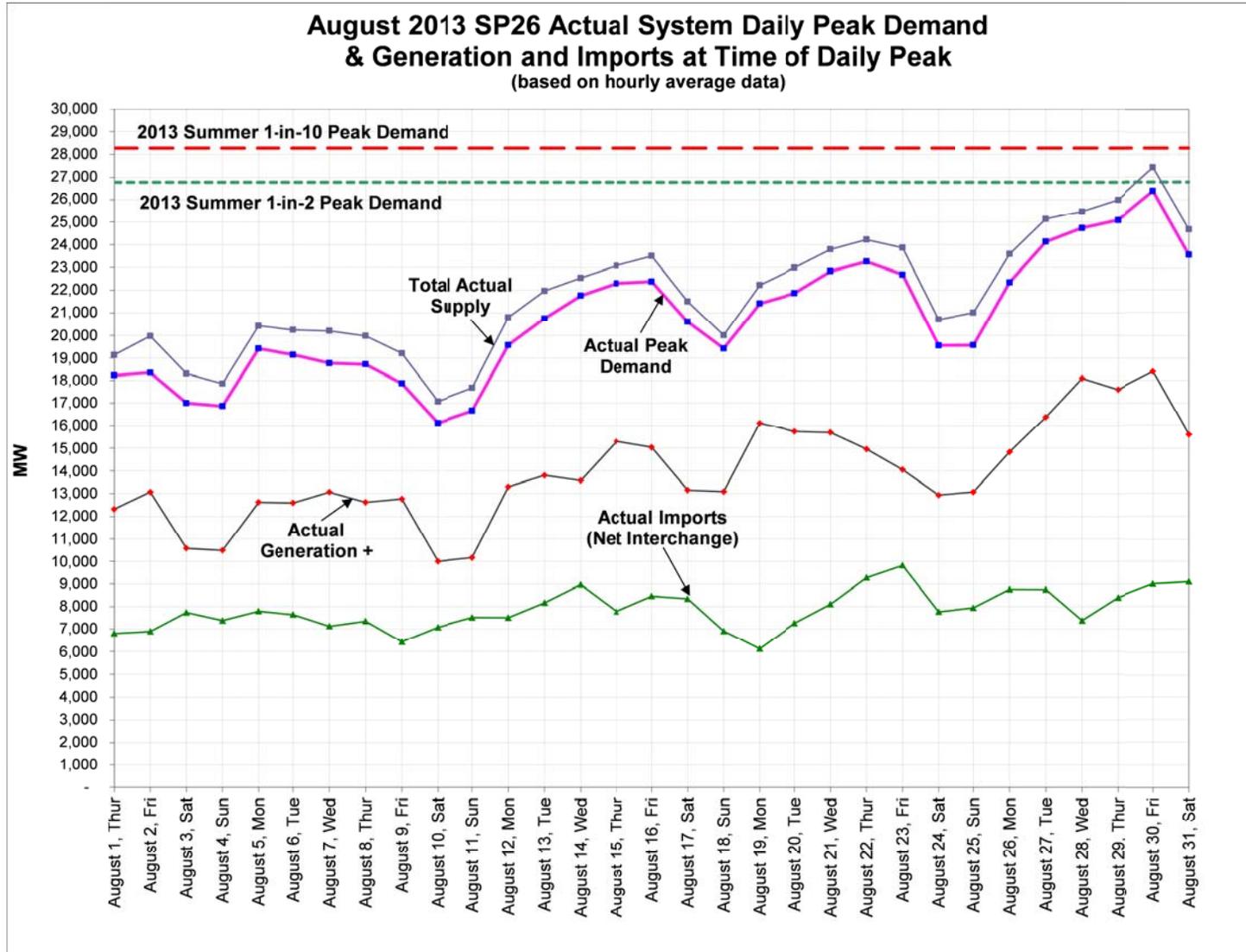
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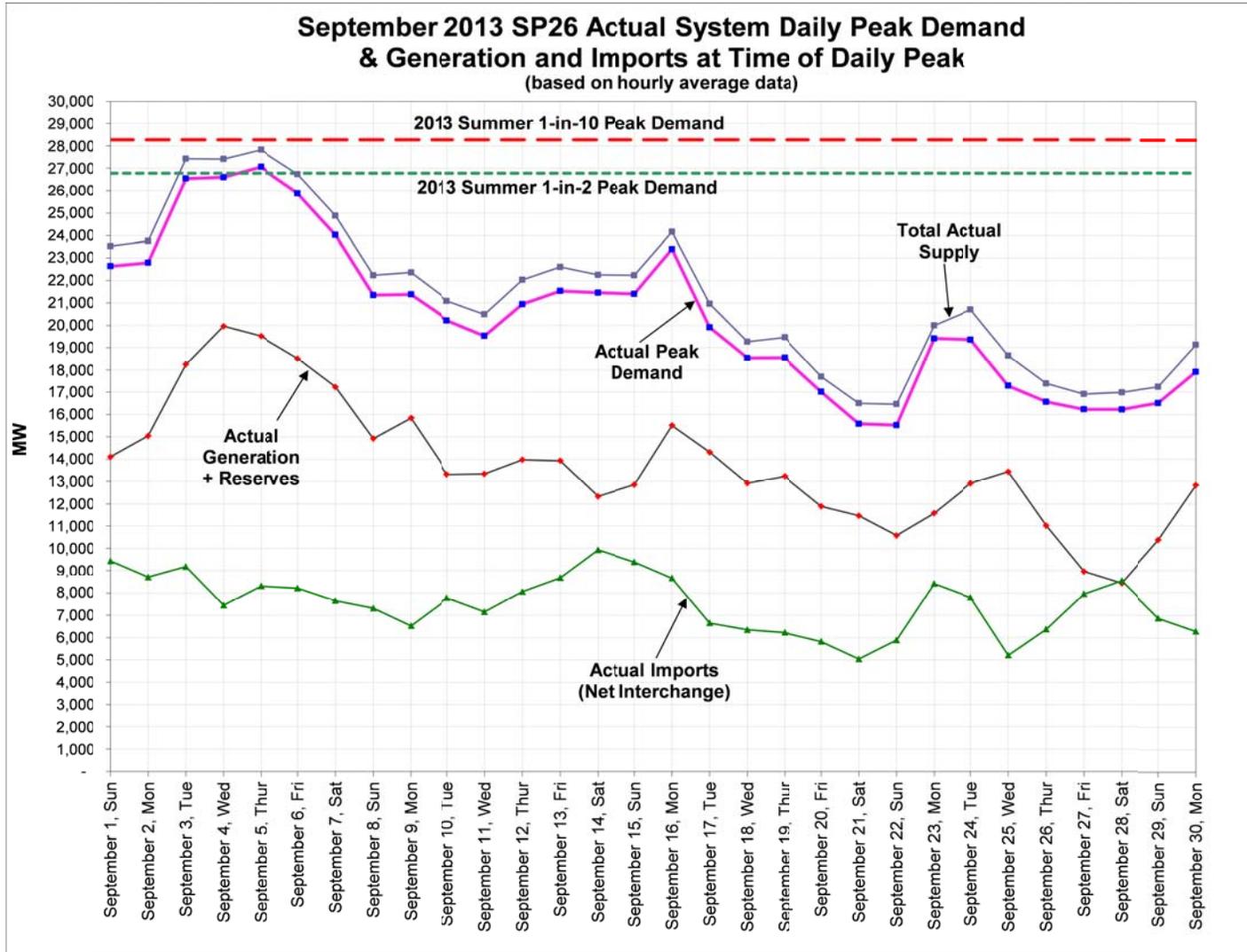
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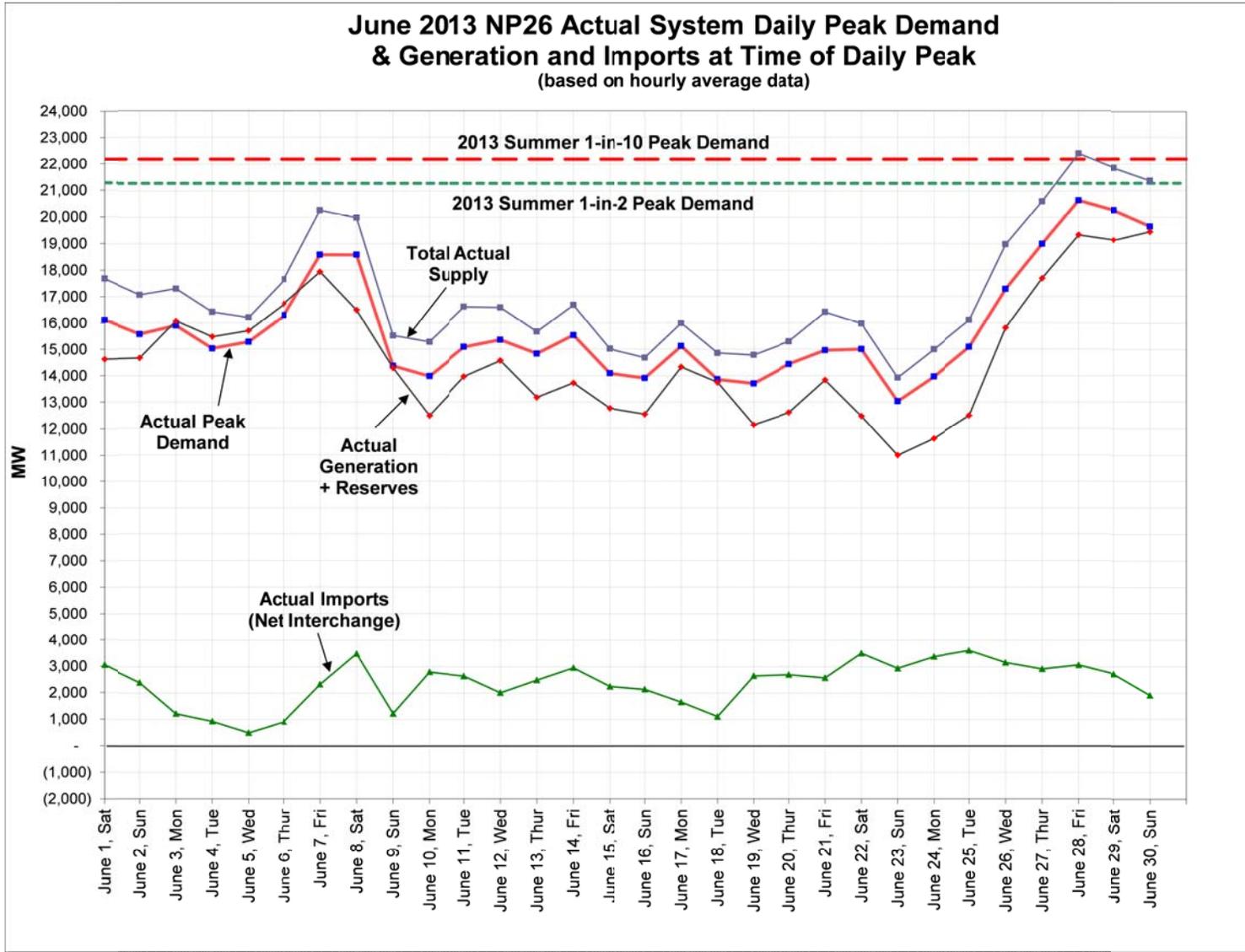
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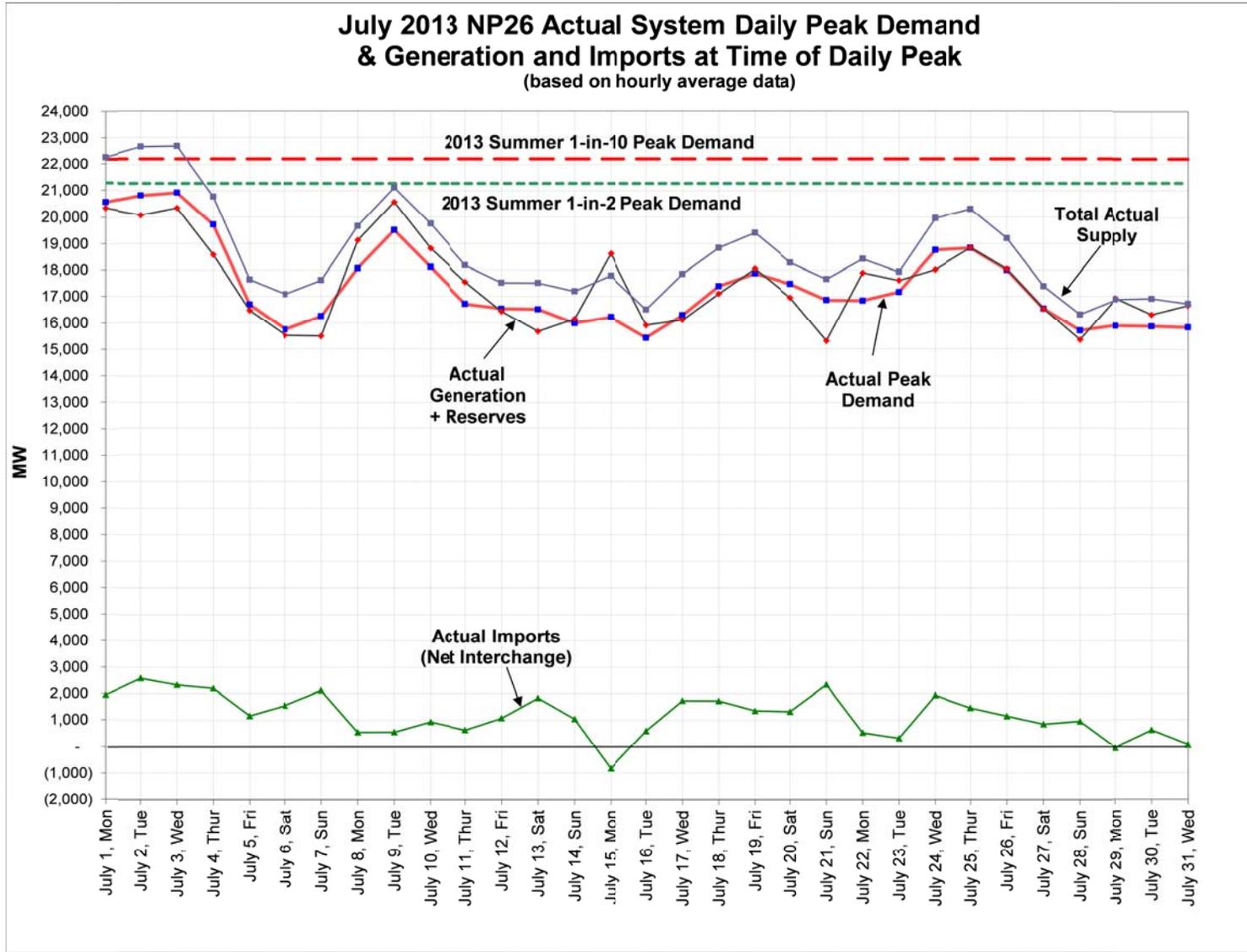
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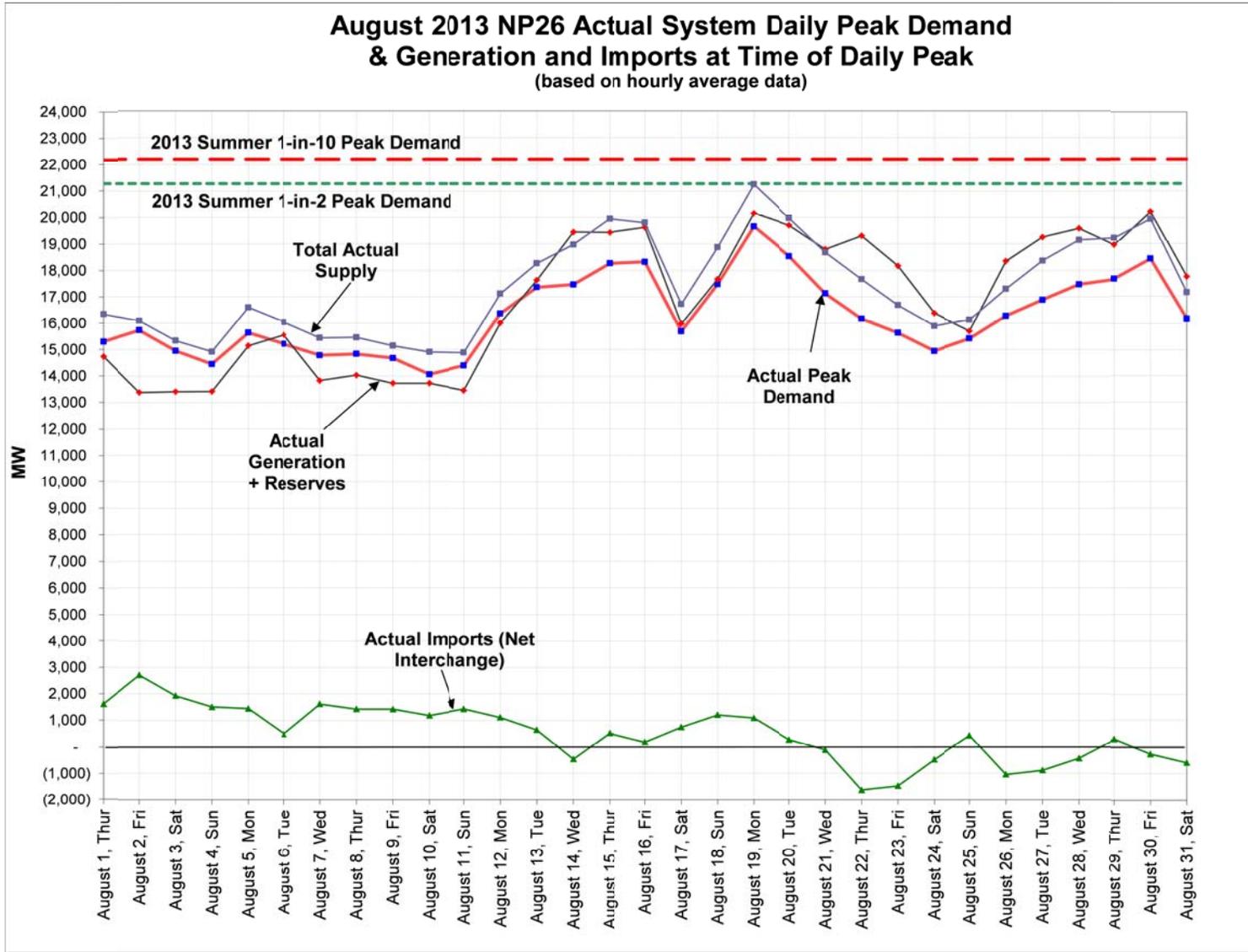
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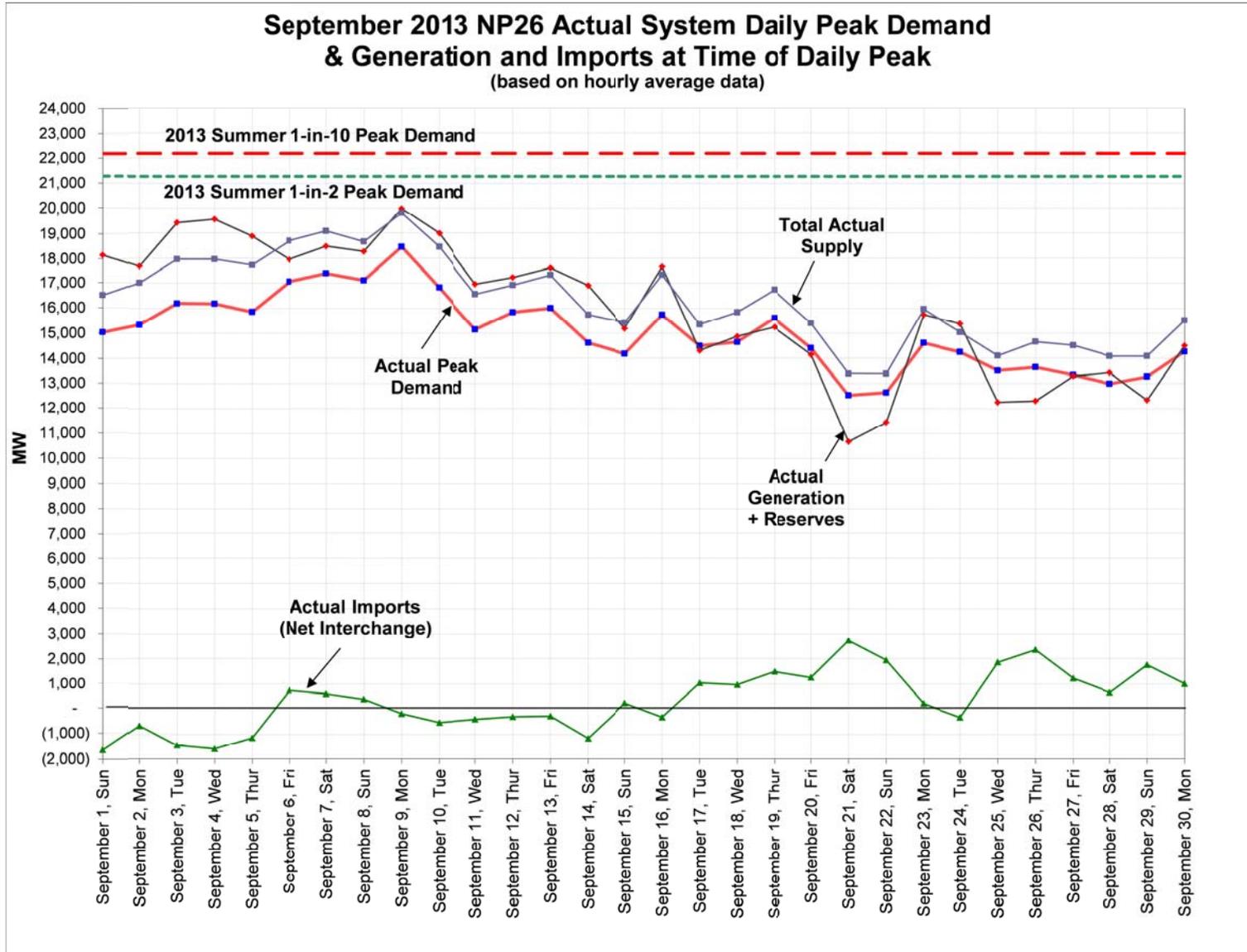
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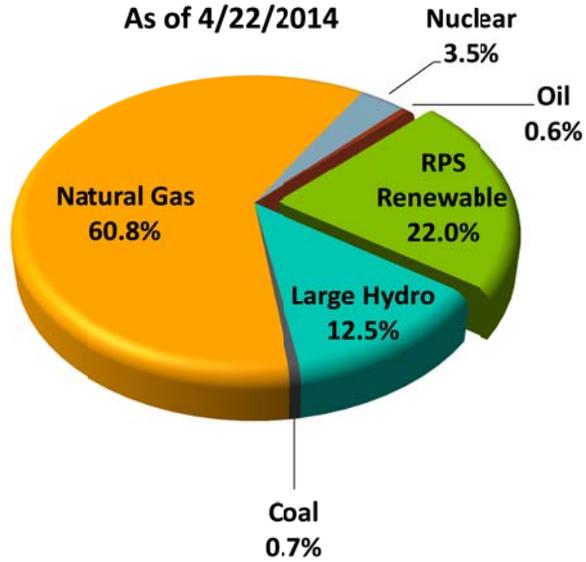
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Appendix B: 2014 ISO NDC and RPS by Fuel Type

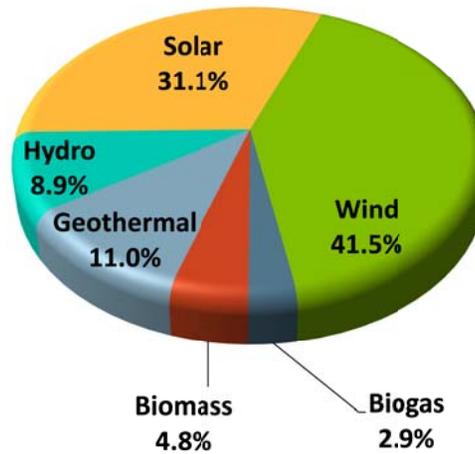
2014 ISO NDC by Fuel Type

As of 4/22/2014

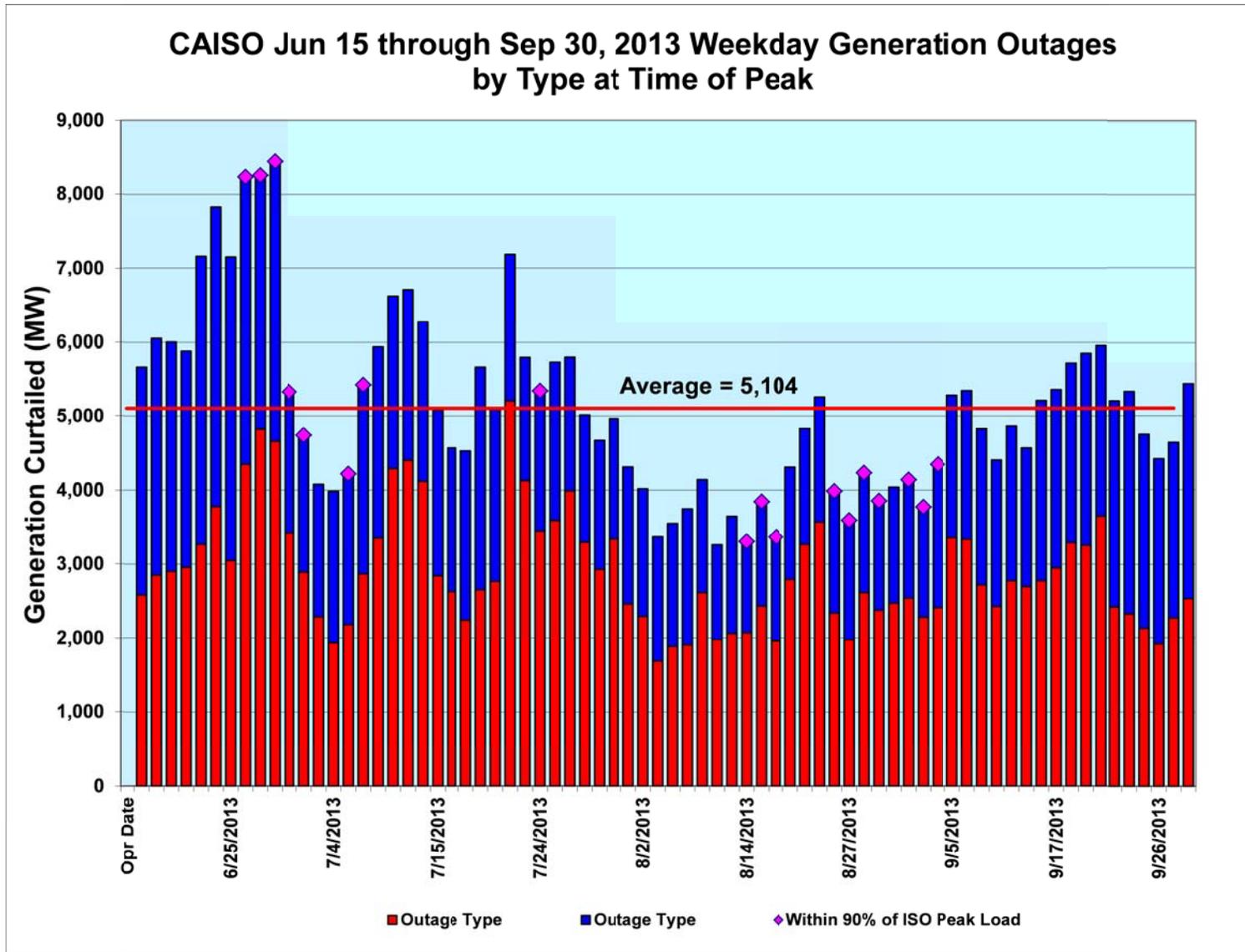


2014 ISO RPS by Fuel Type

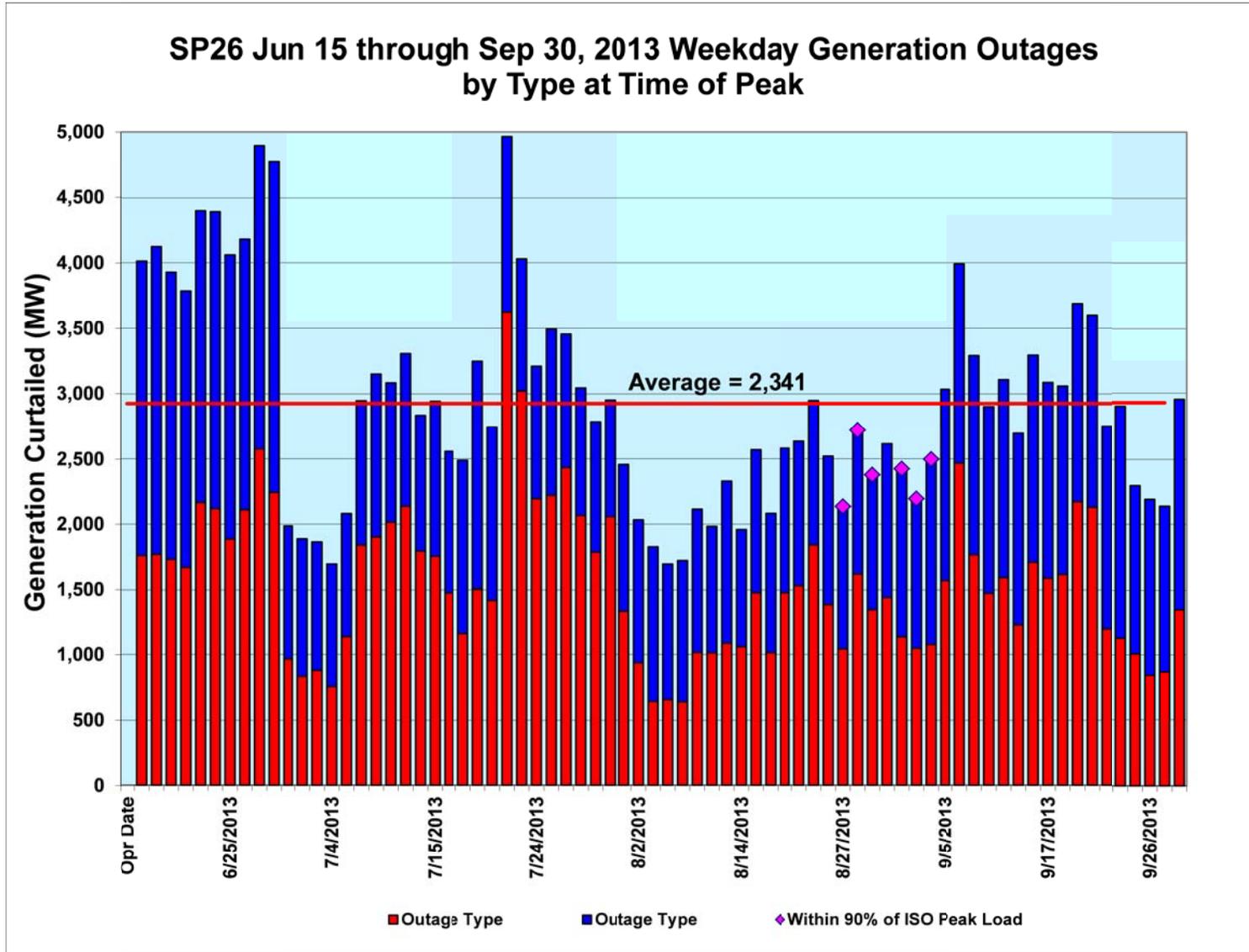
As of 4/22/2014



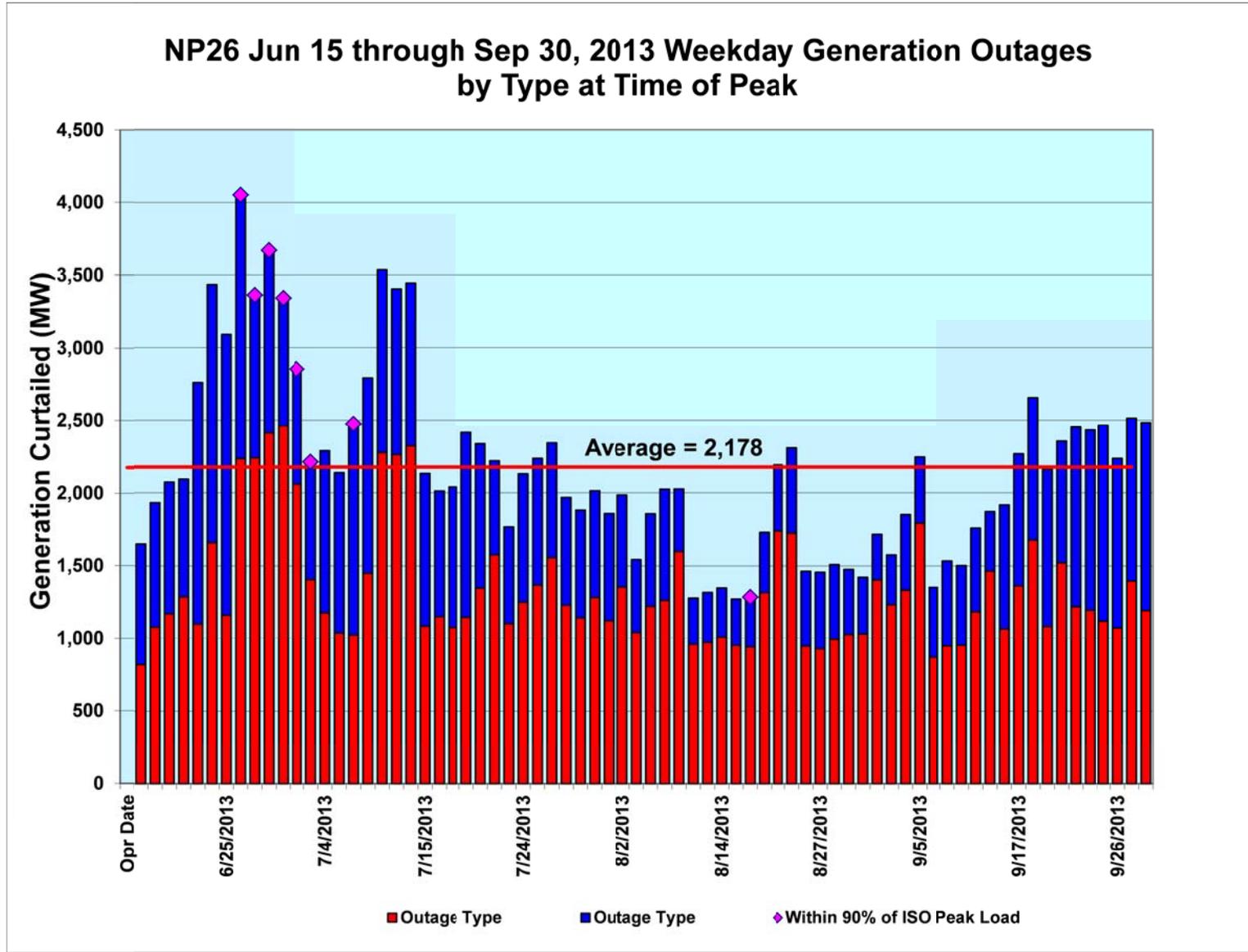
Appendix C: 2011 – 2013 Summer Generation Outage Graphs



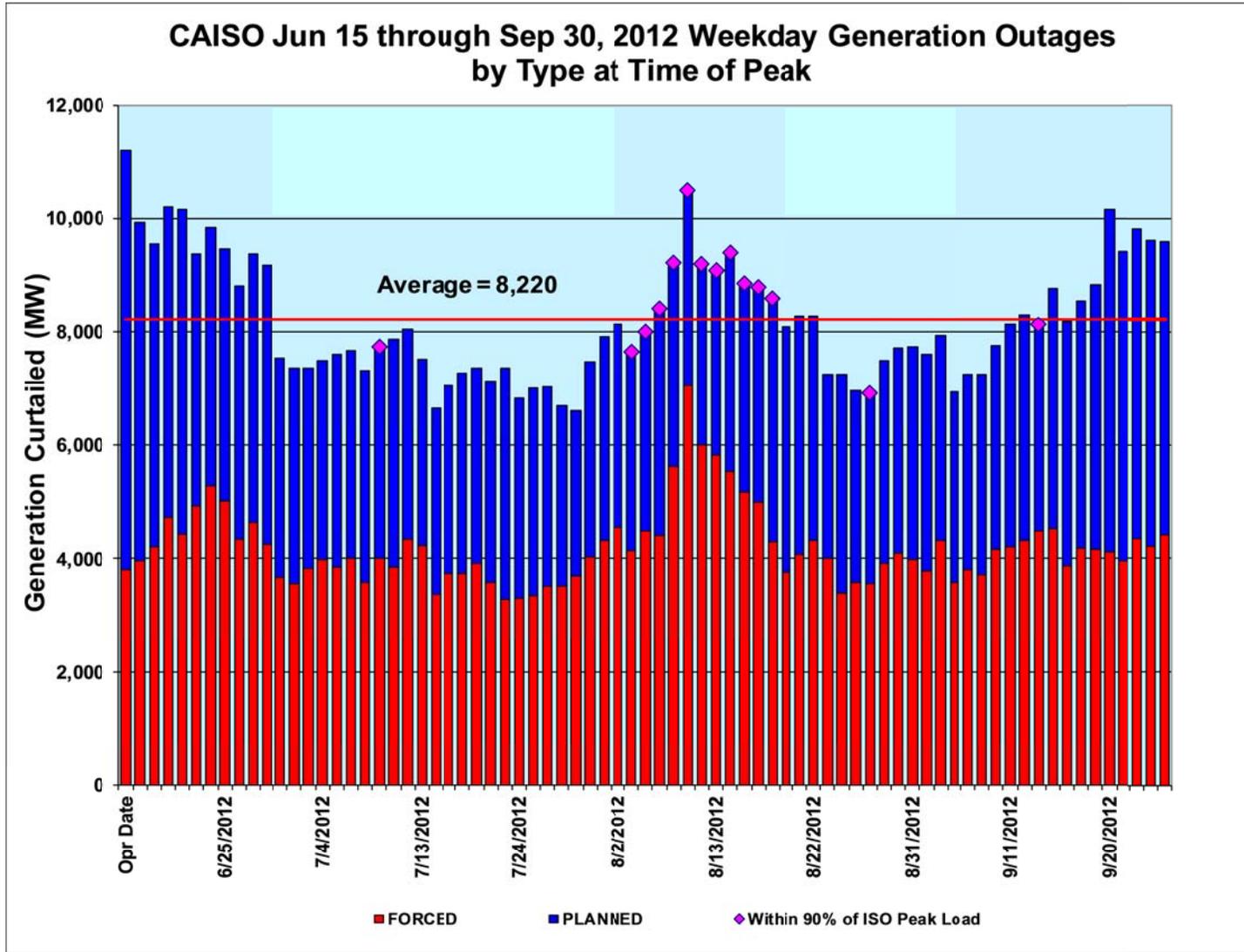
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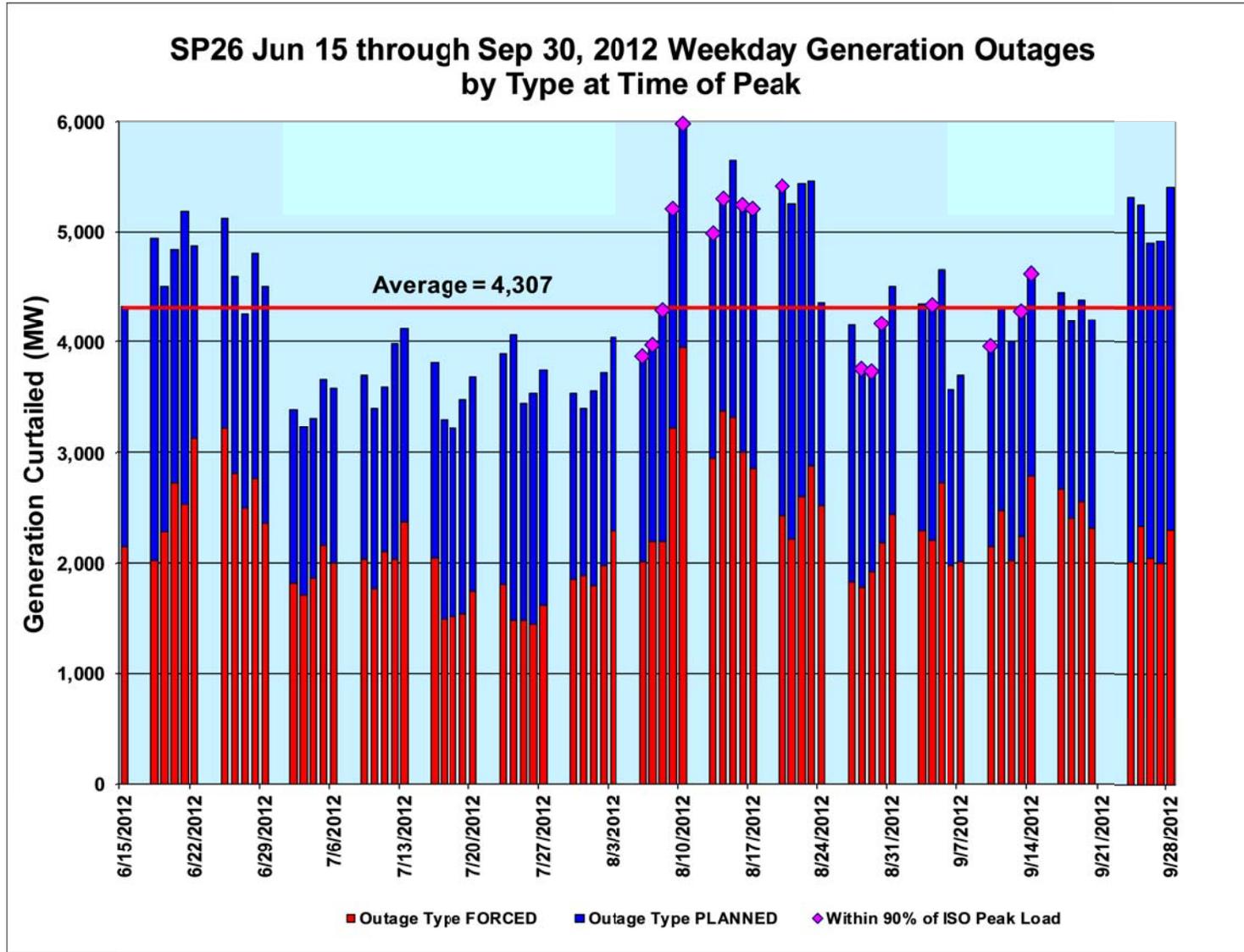
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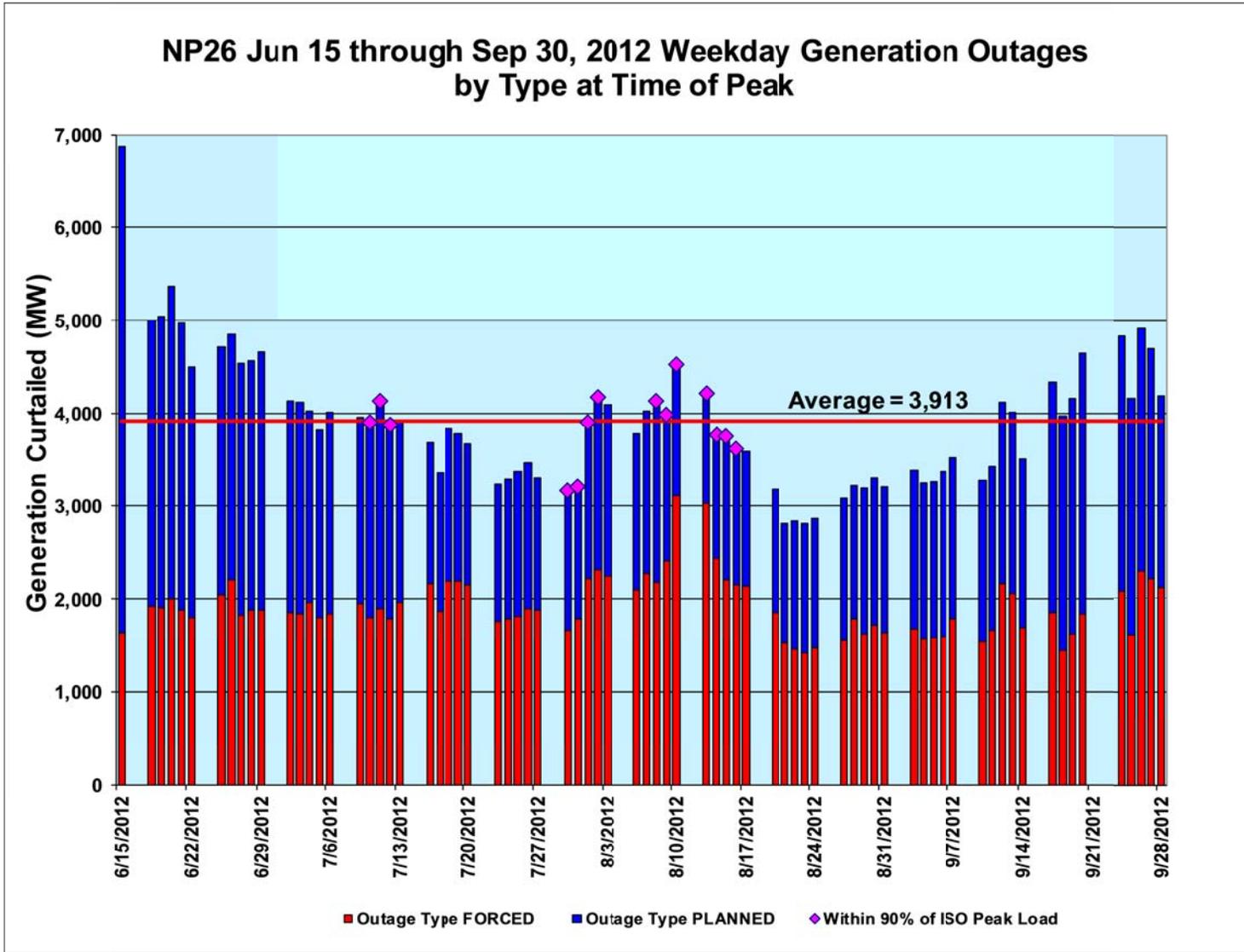
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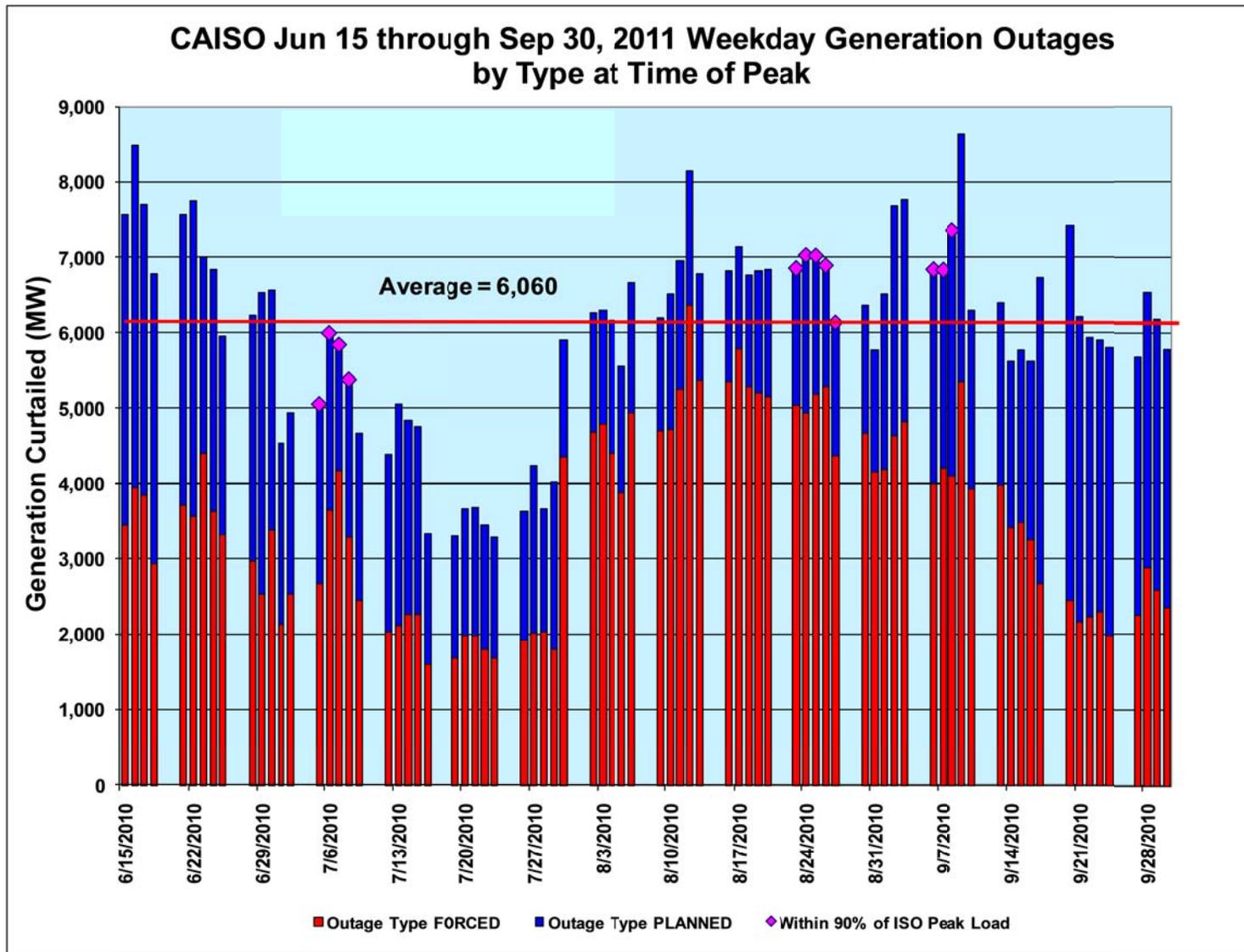
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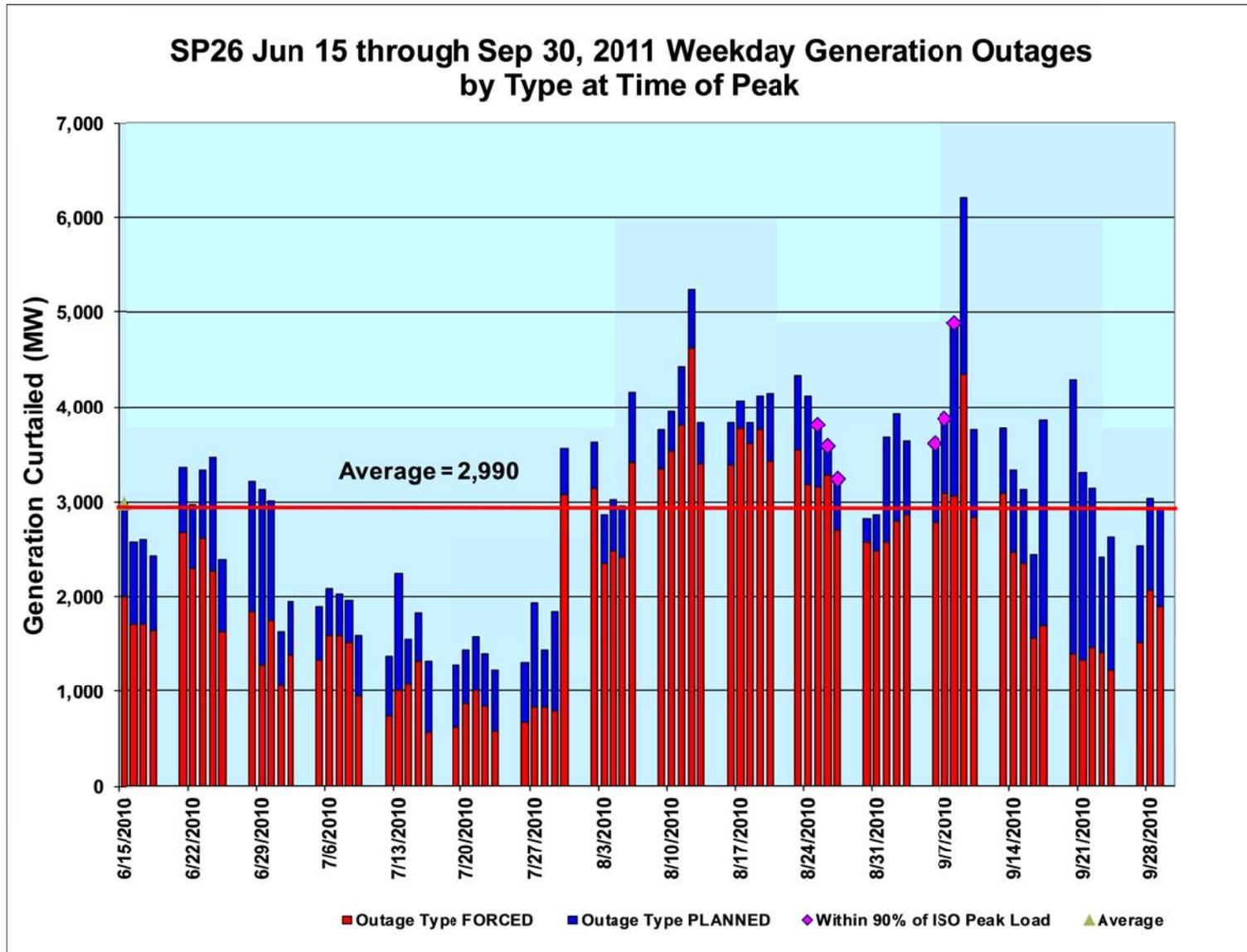
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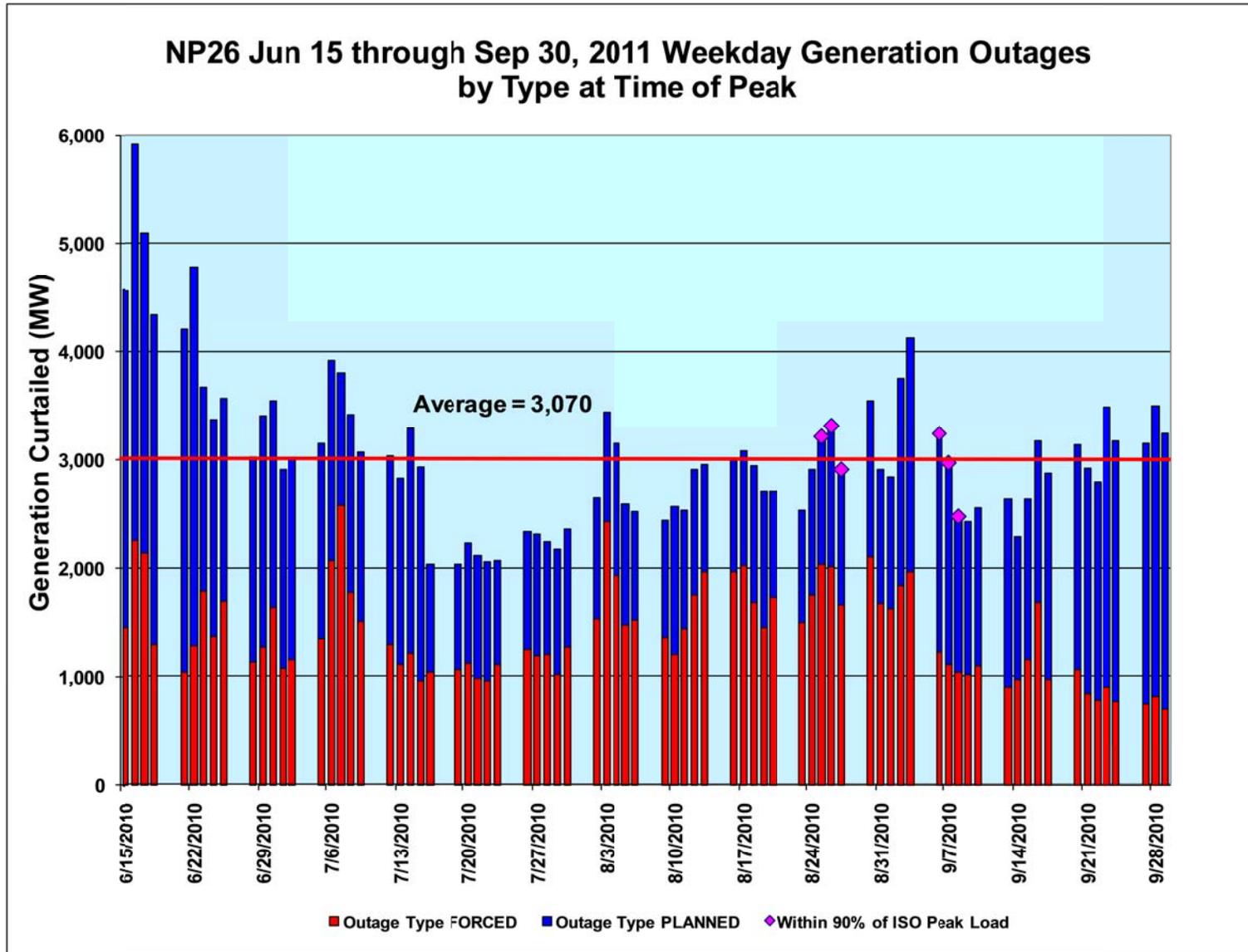
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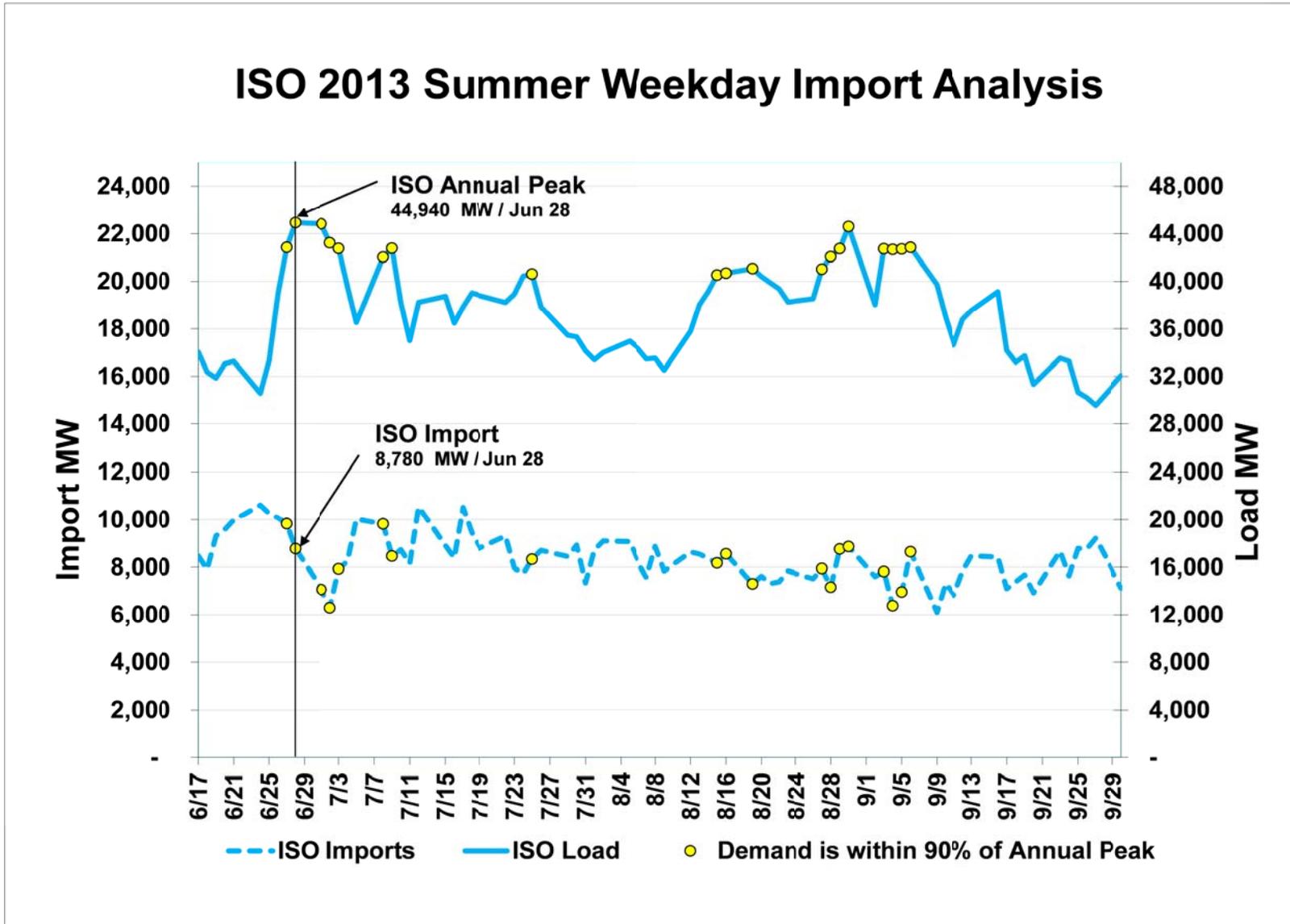
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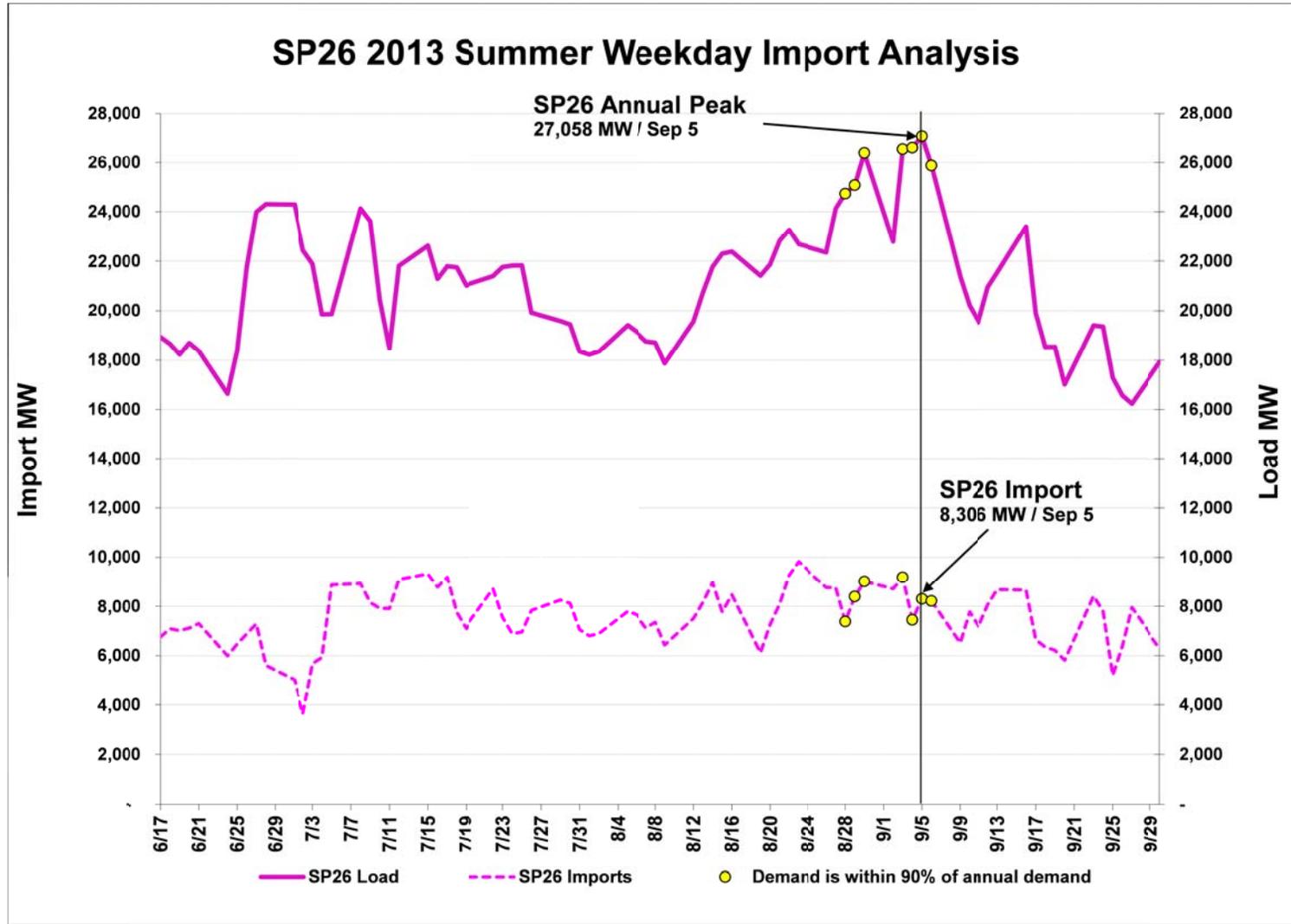
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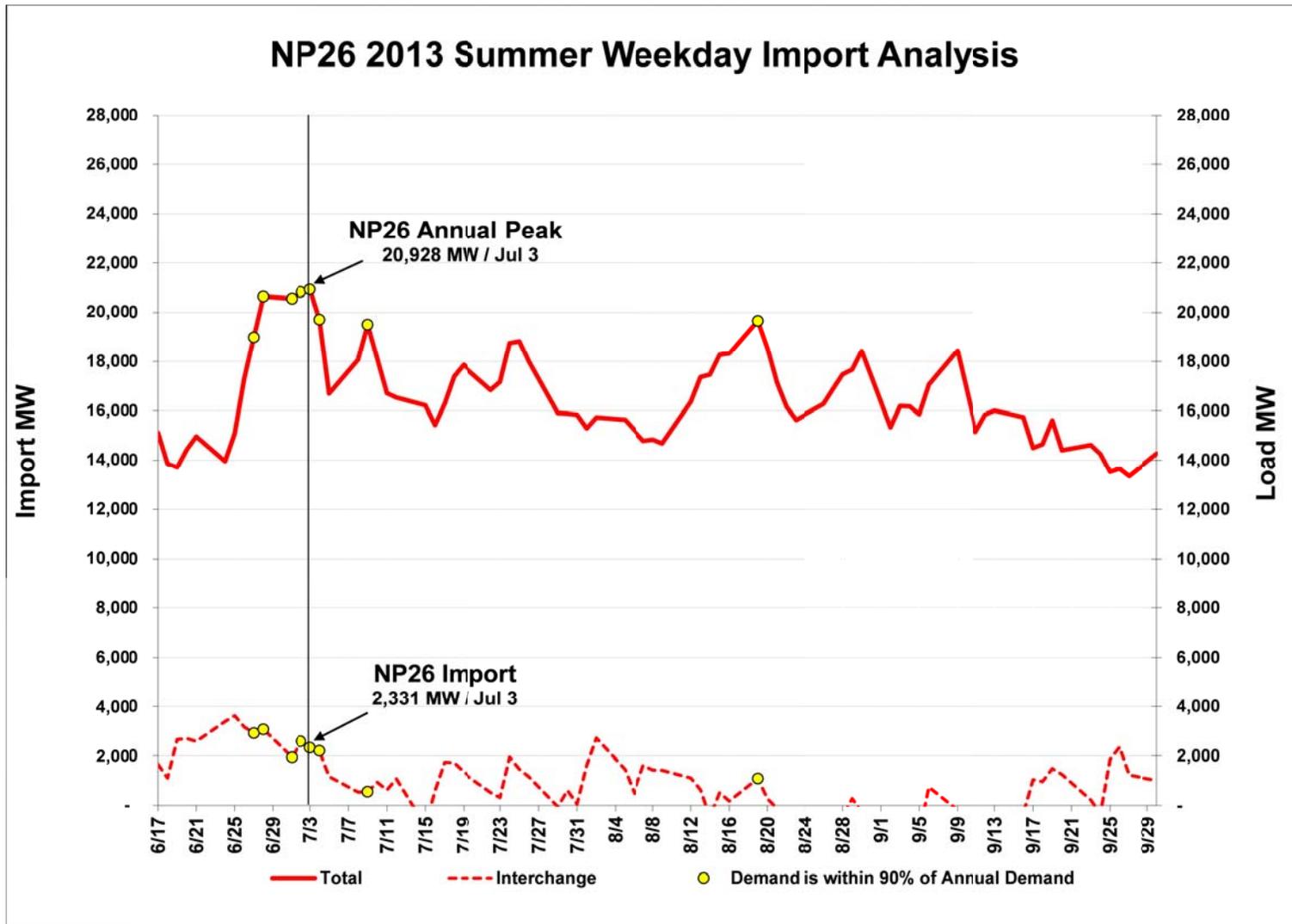
Appendix D: 2011 – 2013 Summer Imports Summary Graphs



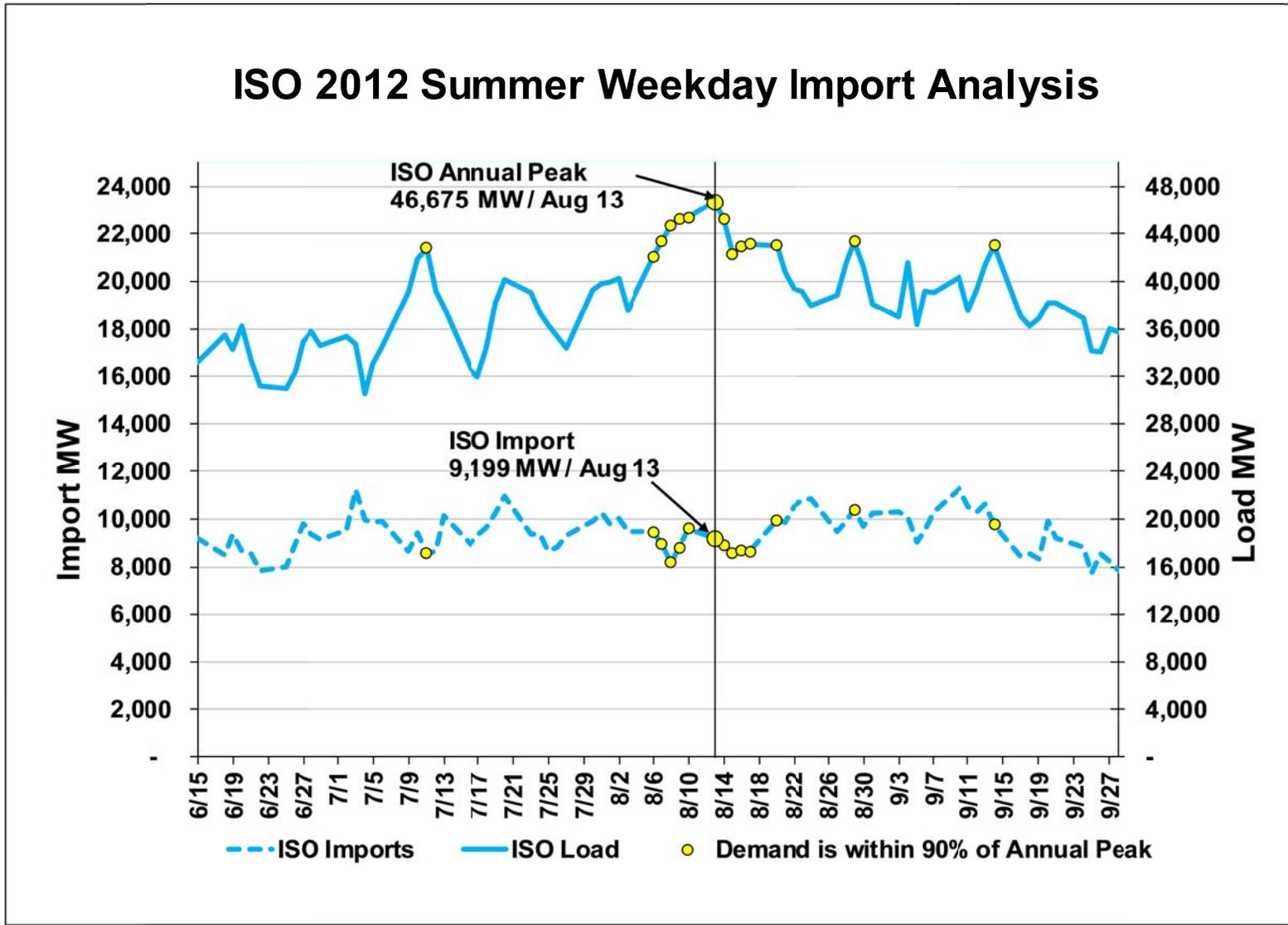
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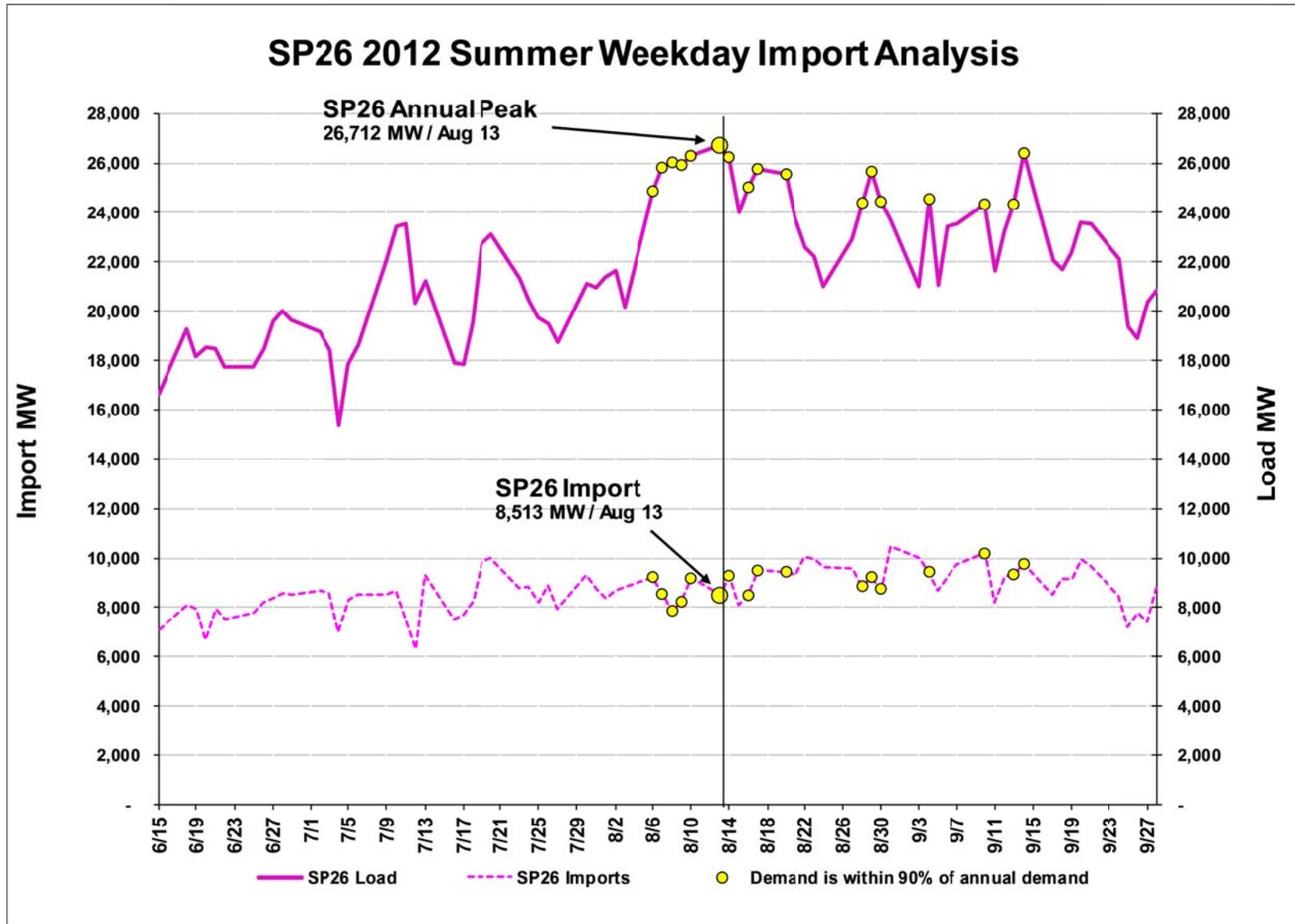
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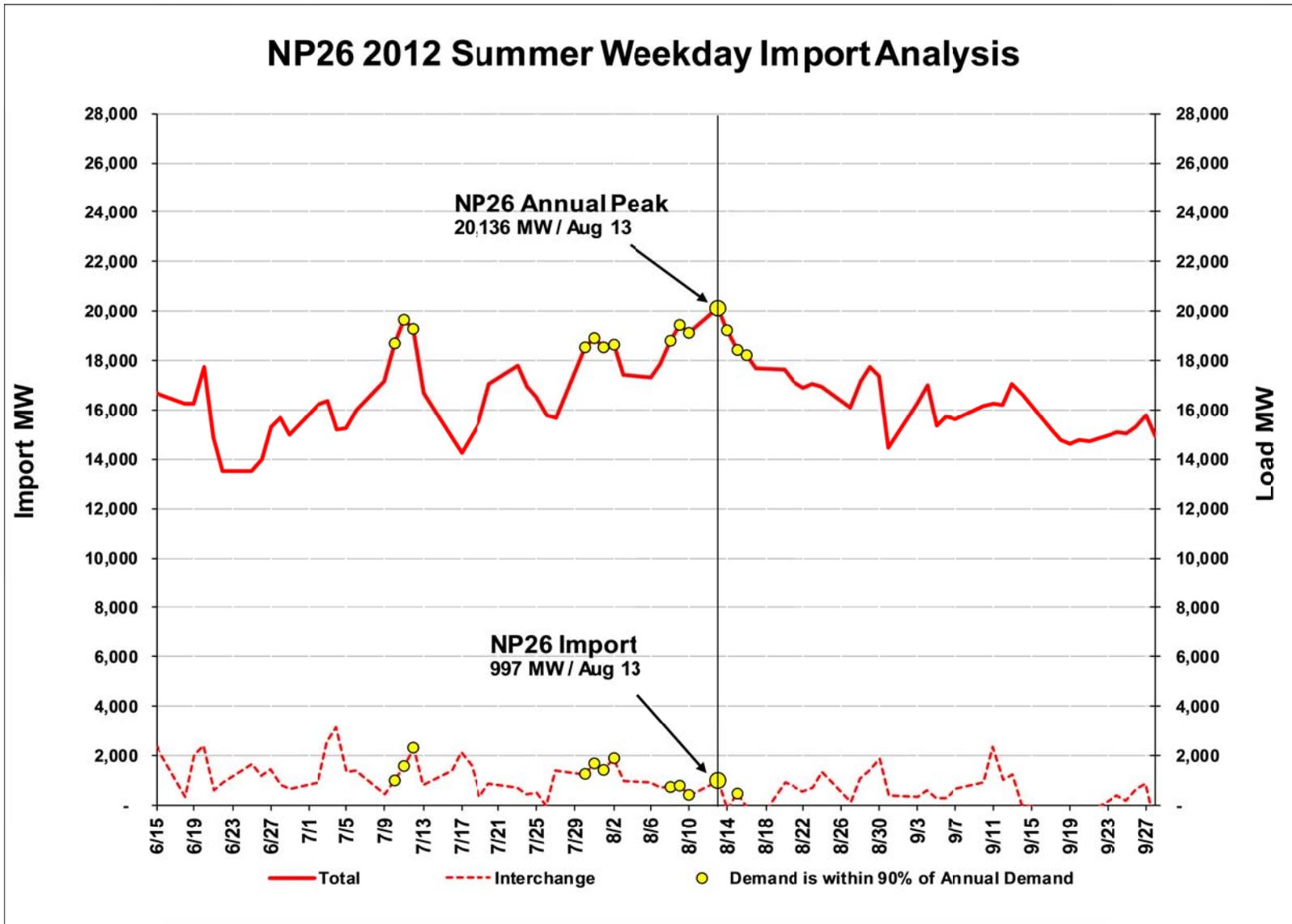
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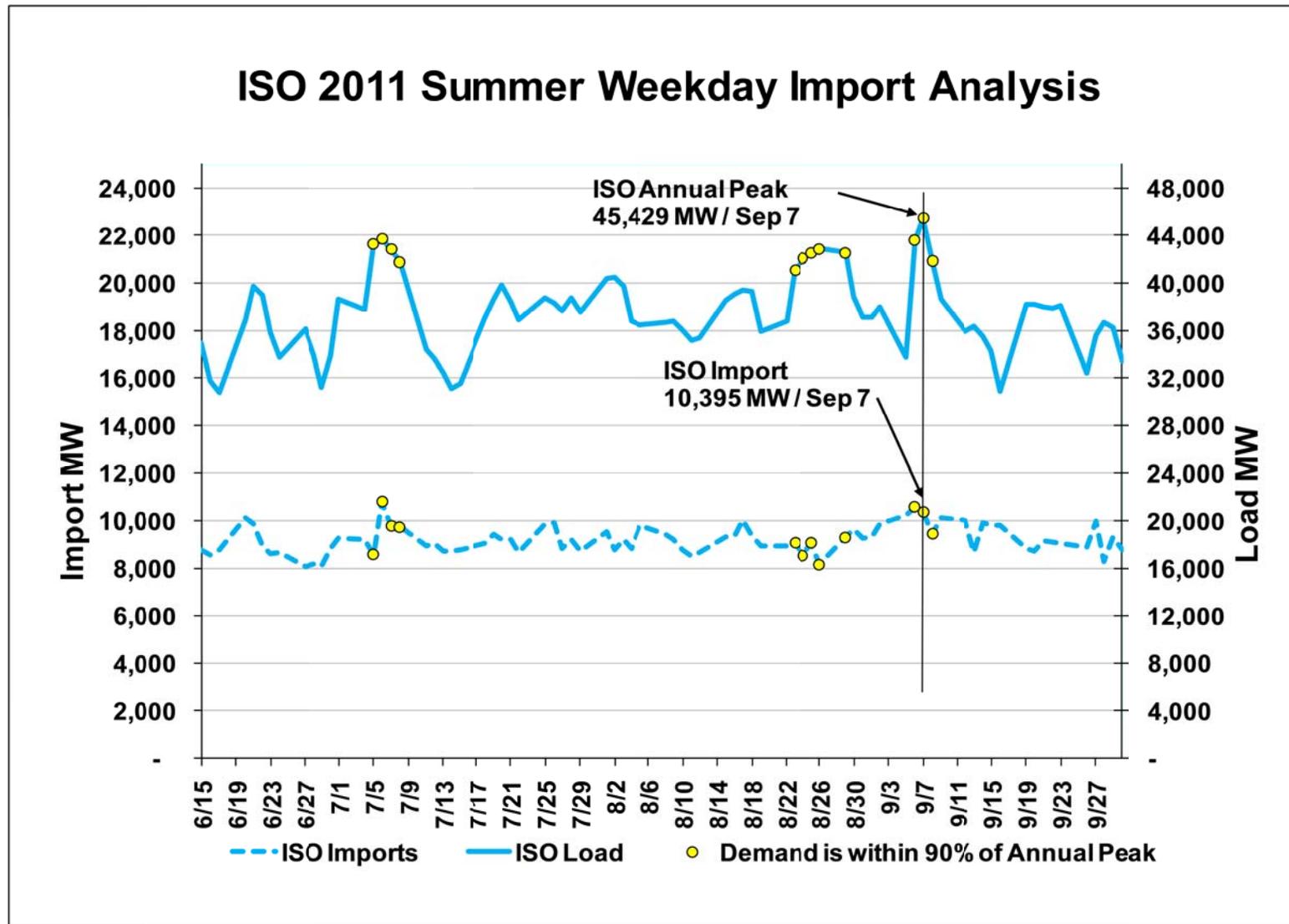
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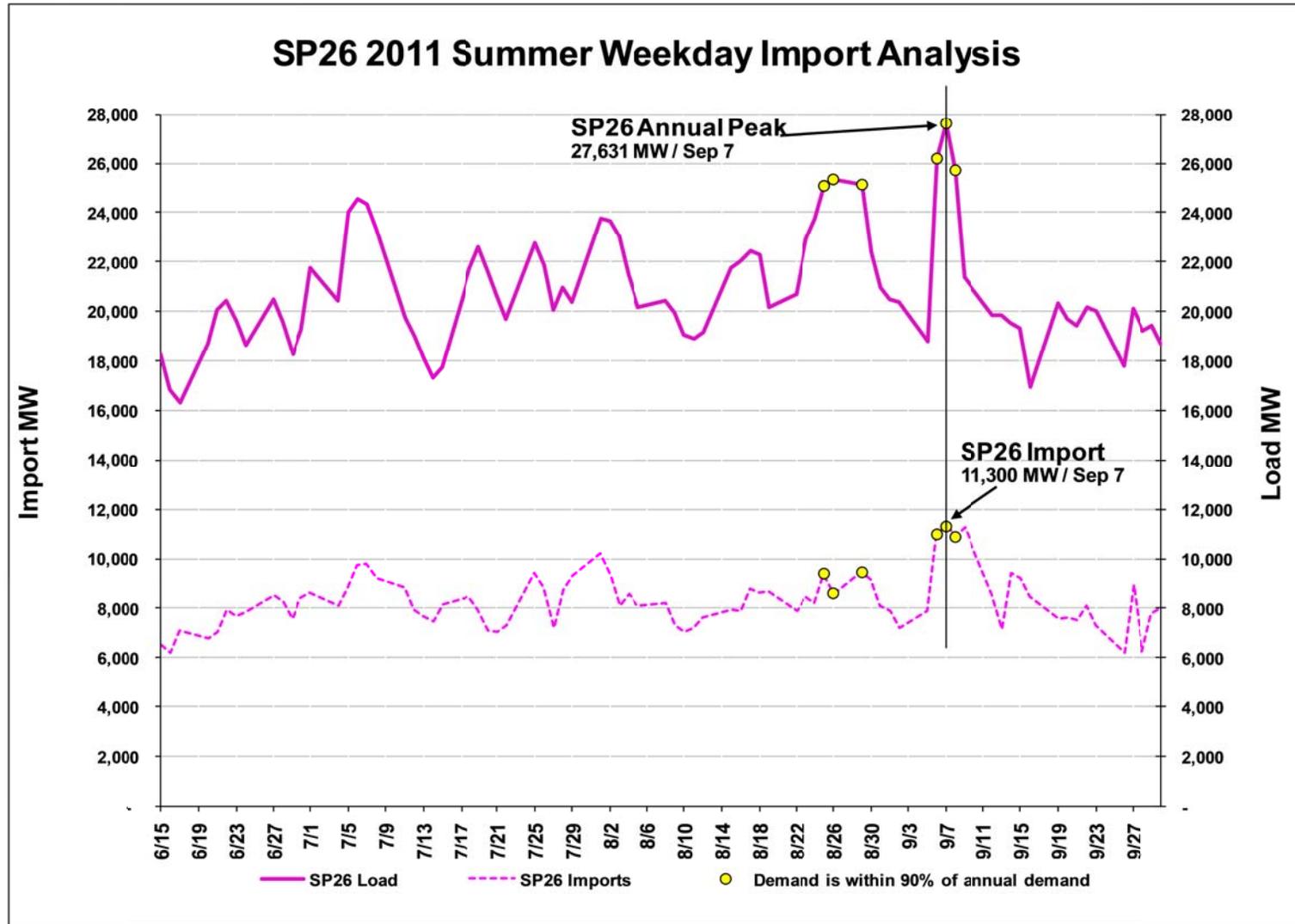
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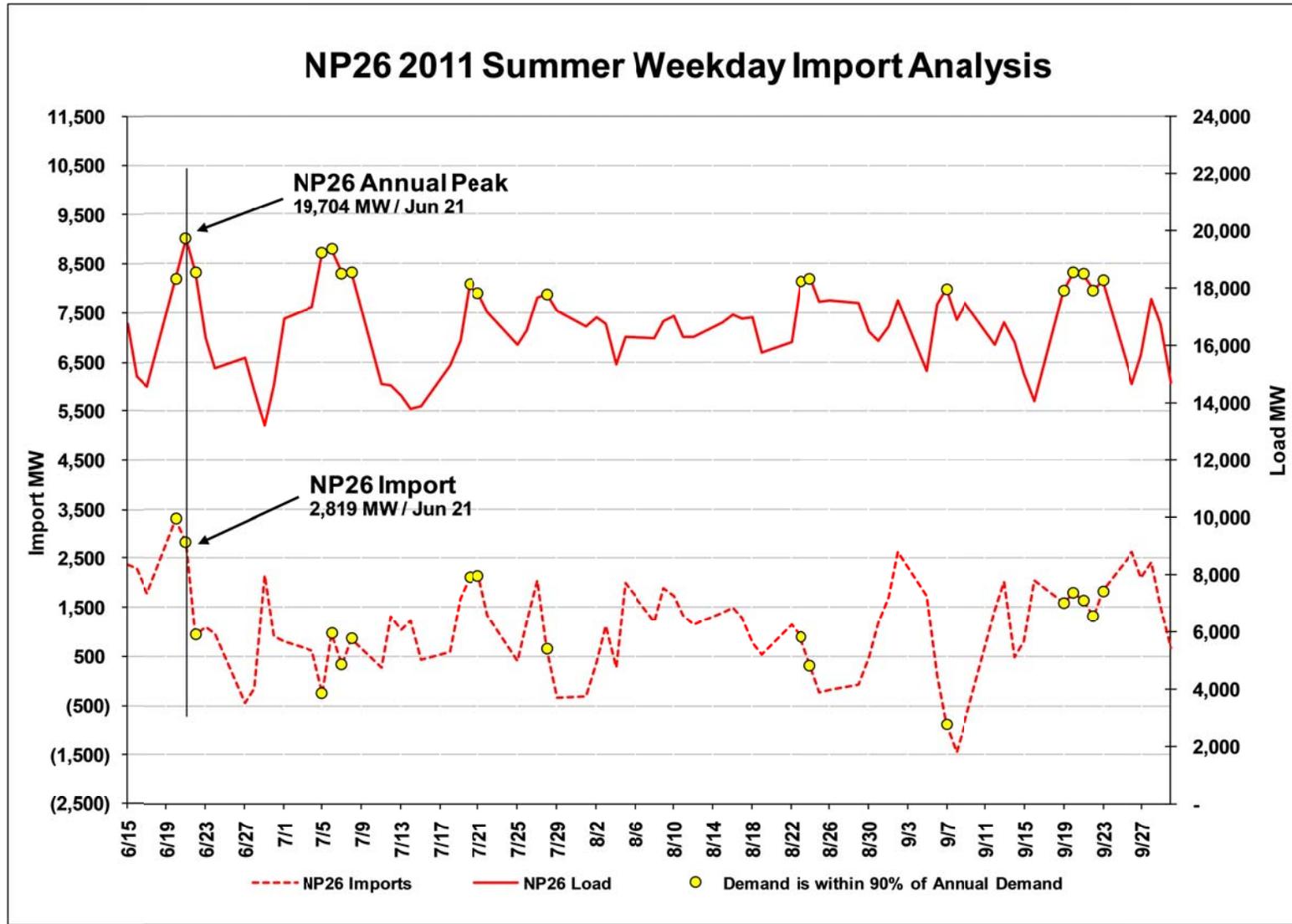
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Appendix D – Continued



Appendix E: 2014 ISO Summer On-Peak NQC Fuel Type

2014 ISO Summer On-Peak NQC by Fuel Type

