INDEX

TESTIMONY OF

REBECCA E. FREDRICKSON, REED C. DAVIS, MICHAEL R. LINN,

DENNIS E. METCALF, PATRICK R. ROCHELLE AND LAUREN E. TENNEY DENISON

Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION RATES STUDY AND RATE DESIGN **Page**

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-18-Q-BPA-09.

A. My name is Reed C. Davis, and my qualifications are contained in BP-18-Q-BPA-06.

A. My name is Michael R. Linn, and my qualifications are contained in BP-18-Q-BPA-23.

A. My name is Dennis E. Metcalf, and my qualifications are contained in BP-18-Q-BPA-27.

A. My name is Patrick R. Rochelle, and my qualifications are contained in BP-18-Q-BPA-32.

A. My name is Lauren E. Tenney Denison, and my qualifications are contained in BP-18-Q-BPA-38.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the Transmission Rates Study and Documentation, BP-18-E-BPA-08, as it pertains to the design and calculation of the proposed transmission rates for BPA’s wholesale transmission products and services for fiscal years (FY) 2018 and 2019. We provide an overview of the methodologies used to develop the proposed rates and describe the specific changes in the rate design for hourly services on the Southern Intertie. We also address the allocation of costs among Network users and proposed changes to the rate schedules and General Rate Schedule Provisions.

Q. Does the study address the proposed rates for all of the Ancillary and Control Area Services in the transmission rate schedules?

A. No. The study addresses the rates for Scheduling, System Control and Dispatch service, and Reactive Supply and Voltage Control from Generation Sources (also referred to as Generation Supplied Reactive) service. The study does not address the other Ancillary and Control Area Services. The Generation Inputs proposed settlement is discussed in BP-18-E-BPA-18.

Section 2: Transmission Rate Design Overview

Q. How does BPA generally develop transmission rates?

A. Through the Integrated Program Review and Capital Integrated Review process, BPA develops the forecast of capital costs and the costs of operating and maintaining its transmission system during the rate period. These costs form the basis for the transmission revenue requirement and are allocated to the various transmission segments based on the facilities assigned to each segment. See Transmission Segmentation Study and Documentation, BP-18-E-BPA-07, and Transmission Revenue Requirement Study, BP-18-E-BPA-09. The Transmission Rates Study and Documentation forecasts the sales for all transmission services, allocates costs to the different transmission services, and designs rates to ensure that the revenues from the forecast sales recover the allocated costs.

Section 3: Rate Design for Hourly Service on the Southern Intertie

Q. What is the Southern Intertie?

The Southern Intertie is a system of transmission lines and substations primarily used to transmit power between the Pacific Northwest and California. The Southern Intertie includes: (1) the 1,000-kV direct current line from the Celilo converter station near The Dalles, Oregon to the Nevada-Oregon border, including the Celilo converter station equipment and the terminal equipment in the Big Eddy substation supporting the direct current line; and (2) the multiple 500-kV alternating current lines from north-central Oregon to the California-Oregon border and all associated terminals and supporting station general. Section 2.3 of the Transmission Segmentation Study and Documentation, BP-18-E-BPA-07, provides a full description of Southern Intertie facilities.

Q. Briefly summarize the Southern Intertie hourly transmission rate design methodology used in the BP-16 rate case.

A. The Southern Intertie hourly rate in BP-16, which applies to both firm and non-firm service, was set using a cost-based methodology intended to recover the cost of service fairly between long-term and short-term users. To accomplish this, the rate was designed so that a customer that reserves hourly transmission 16 hours per day, 5 days per week (these 80 hours are traditionally defined as "heavy load hours") would pay the same amount as a customer that has reserved long-term firm transmission. Setting the hourly rate at this level ensured that a customer that wished to use hourly transmission only during the heavy load hours, when transmission demand was historically the highest, contributed as much to recovery of the Southern Intertie costs as a customer with long-term service. Setting the hourly rate at this level also created a financial incentive for customers to reserve long-term transmission if their demand exceeds 80 hours per week. Linn *et al.*, BPA-16-E-BPA-31, at 3.

Q. Are you proposing to use the same rate design and methodology to develop the rate for hourly services on the Southern Intertie for the BP-18 rate period?

A. We are proposing to continue to use the same cost-based methodology that recovers costs fairly between long-term and short-term users, but we are proposing to set the hourly rate so that a customer that reserves hourly transmission for 25 hours per week pays the same amount as a customer that has reserved long-term firm transmission.

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Q. *Why are you proposing to set the hourly rate based on 25 hours per week, not 80?*

A. As explained in greater detail below, changes in California have effectively reduced the number of heavy load hours, which was the basis of the rate design in BP-16. BPA depends on sales of long-term firm service to recover the majority of the costs of the Southern Intertie. BPA is potentially facing termination of significant amount of its existing contracts for long-term firm service on the Southern Intertie. Given BPA's reliance on sales of long-term firm service to recover the majority of the costs of the Southern Intertie, we believe the risk of under-recovering the costs of the Southern Intertie segment has increased since the BP-16 rate case and that a change to the rate design is necessary.

Q. *Please explain the changes in California.*

A. In the past few years, there has been a large increase in the amount of non-dispatchable resources (primarily solar) in California. The integration of large amounts of solar generation has changed the daily net load shape in California. Net load is total load minus non-dispatchable (wind and solar) generation. Net load represents the energy demand that must be met from dispatchable resources within California and imports. The net load in California during the hours in the middle of the day has trended downward as renewable generation has increased. These are hours that have traditionally been considered part of the 16 heavy load hours that BPA relied on for the assumptions behind the calculation of the hourly rate in BP-16. See Appendix A, Charts 1, 2, 2.1, 3 and 4.

This downward trend of net load in the middle of the day is known in the industry as the "duck curve" and has been studied by the California Independent System Operator (CAISO), the entity that operates the majority of California's transmission grid and its organized wholesale electricity markets. The CAISO has concluded that heavy load or peak hours are shifting to a handful of hours in the early evening.

See https://www.caiso.com/Documents/MatchingTimeOfUsePeriodsWithGridConditions-FastFacts.pdf.

The change in the daily net load shape has reduced the demand for imports during the afternoon, a portion of the day that has traditionally been included in the definition of heavy load hours. Demand for imports is now the highest only during a few early evening peak hours. As more solar generation is interconnected to meet California's renewable portfolio standards, BPA anticipates that the trend of decreasing net load in the middle of the day will continue. See Appendix A, Charts 4, 5, and 6. As a result of these conditions and in response to feedback from several utilities that standard peak and off-peak products were no longer sufficient to meet their needs in areas with high solar concentration, the Western Systems Power Pool (WSPP) created a new power product for the afternoon peak.

Q. *Are there rules governing the markets in California that may affect how BPA's transmission customers reserve transmission on the Southern Intertie?*

A. Yes. The CAISO established rules for its day-ahead market in 2009. The day-ahead market is where the majority of generation needed to meet forecast demand in the CAISO footprint is acquired. The CAISO day-ahead market does not require that participants have firm transmission to submit a bid to sell into the market, nor does the market consider the difference in transmission priority between firm and non-firm transmission when awarding bids. The CAISO also does not require those receiving day-ahead awards to schedule prior to the Western Electricity Coordinating Council (WECC) pre-schedule deadline. These rules allow customers to bid into the day-ahead market prior to purchasing transmission and then acquire transmission only if they receive a day-ahead award. Not only does a customer not need firm transmission to bid into the CAISO day-ahead market, but a customer without firm transmission that receives an award will effectively ensure that non-firm inventory is available. Because the CAISO day-ahead market limits the awards from resources in the Pacific Northwest to the CAISO's portion of the Southern Intertie, when a seller without firm transmission receives a day-ahead award, then the long-term firm transmission rights holders may not be able to schedule up to their full rights. In this situation, BPA, as an OATT provider, sells the difference between the firm reservations and the firm schedules as non-firm transmission. Thus, under normal conditions, the seller bidding into the CAISO market without firm transmission can anticipate that non-firm transmission inventory will become available on the northern half of the intertie if its bid is selected in the CAISO market.

The CAISO markets also do not trade in defined heavy load hour blocks (16-hour blocks). This allows participants in the CAISO day-ahead market to purchase transmission only during the highest demand hours, which, as discussed above, are now concentrated in a few evening hours. This reduces the incentive to purchase long-term firm under the current rate structure.

Q. The CAISO's market rules have existed since 2009 and were discussed in the last rate case, where BPA decided to not change its hourly rate methodology. See BP-16 Administrator's Record of Decision, BP-16-A-02, at 111-12. What has changed?

A. In evaluating whether the CAISO's market rules had an effect on long-term firm sales in BP-16, BPA found that "the Southern Intertie remains fully subscribed in the southbound direction, and BPA has a long queue of customers waiting for capacity," despite the CAISO's market rules. *Id.* at 111. This is no longer the case. As described below, the amount of megawatts in the queue is greatly reduced, and some customers are choosing not to accept new offers of long-term firm service. We believe this could be due in part to the CAISO's market rules.

Q. Why does it matter that CAISO's market rules may be having a negative effect on long-term firm sales, or that the "duck curve" is reducing the demand for imports in hours that were previously considered to be high demand?

A. Both the "duck curve" and the CAISO market rules may reduce the amount of long-term firm service that BPA sells on the Southern Intertie. BPA's long-term firm transmission agreements require customers to commit to take-and-pay service, typically for multiple years. These agreements provide a stable and predictable revenue stream for purposes of developing BPA's sales and revenue forecasts for the rate period compared to purchases of monthly, daily, or hourly service. Shorter-term sales are more difficult to forecast because transmission reservations are more likely to depend on the year-to-year economics of selling energy over the Southern Intertie on a short-term basis. If a larger portion of Southern Intertie reservations have durations that are short-term (less than one year), revenue received from reservations on the Southern Intertie would be much more variable. This variability, driven by market conditions that vary from year to year, may impact BPA's ability to set rates that recover the costs of the Southern Intertie during the rate period.

Q. Please describe BPA's queue of requests for long-term firm service on BPA's Southern Intertie.

A. New requests for long-term firm service on the Southern Intertie are placed into a queue that includes all pending requests. Since September 2014, the amount of requests in the queue has decreased from 6228 MW to 1002 MW, a reduction of 5226 MW.

Q. *Please describe BPA's recent experience with offering long-term firm service to customers with requests pending in the queue.*

A. BPA offers service to customers with pending requests when it becomes available, and customers are free to accept or reject those offers. If a customer rejects service offered by BPA, its request is removed from the queue. In the BP-16 rate period, 460 MW were removed from the queue because customers had rejected offers of long-term firm service. In addition, certain customers had the option to "compete" for 230 MW of long-term firm service on the Southern Intertie in response to a request to renew service, but the customers chose not to do so. In other words, those customers also rejected offers of long-term firm service.

Q. *What is the amount of long-term service that will terminate before the end of the FY 2018–2019 rate period if the service is not renewed?*

A. During the FY 2018–2019 rate period, 2314 MW of long-term firm service will terminate unless customers decide to renew their service. This is significantly higher than the 1303 MW of long-term firm service that customers had the option of terminating or renewing during the BP-16 rate period. Similarly, at least 640 MW would terminate during the FY 2020–2021 rate period.

Although a large number of customers not renewing service would be a significant change from previous years where long-term firm capacity from south to north has been fully subscribed, we are concerned that we might be seeing the start of trend where customers with pending requests are rejecting offers of long-term firm service. In addition, some of our long-term firm customers, including those with upcoming decisions to renew or terminate service, are telling BPA that long-term firm service is not as attractive as it once was, and there is an especially large amount of megawatts that are coming up for renewal in the FY 2018–2019 rate period. JP06 Br., BP-16-B-JP06-01, at 9-10; JP17 Br., BP-16-B-JP17-01, at 4. All of these factors lead us to conclude that we should increase the hourly rate to more accurately reflect the hours of highest demand in California and maintain the incentive for customers to choose long-term firm transmission.

Q. Given the changes from the BP-16 rate case, how are you planning to increase the hourly rate?

A. As stated above, our proposal updates the methodology used in BP-16 to reflect that the number of heavy load hours has been reduced due to changes of the generation mix in California. We propose setting the Southern Intertie hourly rate by first multiplying the long-term firm rate by 24/5 (24 hours per day divided by 5 hours) rather than the 24/16 factor used for BP-16 rate. This calculation results in a rate that is higher than a simple pro-rata fraction of the long-term rate and than the BP-16 rate. Nevertheless, the objective behind the rate design remains largely the same. The rate is set to ensure that customers that decide to reserve transmission only during the periods when California net loads are the highest pay the same amount as long-term firm customers that have the right to schedule transmission 24 hours a day. We propose to continue to multiply the result by 7/5 (7 days a week divided by 5 weekdays) to ensure that customers that reserve transmission for five weekdays, again when net loads are typically highest, pay the same amount as long-term firm customers that have the right to schedule every day of the week. *See* Appendix A, Chart 2.

The practical result of the methodology is that a customer that reserves 1 MW of hourly firm or non-firm transmission for 25 hours per week (5 hours a day multiplied by 5 days) pays the same amount as a long-term firm customer buying 1 MW.

Q. Is the proposed rate design consistent with the principles supporting the rate design for hourly services on the Southern Intertie for the BP-16 rate period?

A. Yes. The design for the BP-16 rate uses a cost-based methodology and is intended to recover the costs of service equitably between long-term and short-term users. If the rate for hourly transmission products were simply a pro-rata share of the long-term rate, many customers would have an incentive to purchase hourly service only in the hours of high use. In that case, hourly customers would be getting a larger share of the benefit of the transmission line without bearing any long-term cost risk. The BP-16 rate design addressed this possible inequity by setting an hourly rate that would recover the same costs as the long-term rate if hourly products were purchased only in traditional heavy load hours (16 hours per day, 5 days per week). The proposed rate design for BP-18 continues to apply the principles of fairly allocating costs and cost-based rate design while taking into account how changes in California's generation mix have effectively decreased the number of heavy load hours in California to 25 hours per week.

Q. What is the Southern Intertie hourly rate under your proposal?

A. The rate for hourly firm and non-firm service is 11.49 mills per kWh.

Q. You mainly discuss the dynamics of deliveries from north to south on the Southern Intertie and the need to set an hourly rate that is responsive to conditions in California. Are you proposing a different rate treatment for hourly deliveries in the south-to-north direction?

A. Yes, we are proposing to discount hourly service on the Southern Intertie in the south to north direction. For south-to-north transactions (*i.e.,* transactions delivering power to the Pacific Northwest), BPA is not seeing the same changes that are present in California. The reduction in heavy load hours that are part of the "duck curve" is not present in the Pacific Northwest because solar generation is not growing as rapidly as in California. Therefore, 80 heavy load hours per week still accurately reflects the hours of highest demand in the Pacific Northwest.

We considered setting separate, directional rates for hourly service, but we were concerned that setting a lower rate for south to north (for example, by using the 80-hours-per-week divisor) would allow customers to purchase hourly firm south to north, then redirect to hourly non-firm north to south. Applying a discount for hourly service in the south-to-north direction allows us to recall that discount if the transmission is redirected or resold. We are aware that other Open Access Transmission Tariff providers use discounting as an incentive to increase usage on their systems.

Section 4: Network Cost Allocation

Q. How are you proposing to allocate Network segment costs for the BP-18 rate period?

A. We propose to allocate Network segment costs to Point to Point (PTP) and Integration of Resources (IR) customers based on contract demand and to Network Integration Transmission Service (NT) customers based on load using the 12 non-coincidental peak (NCP) method. This is the same cost allocation methodology we used for the BP-14 and BP-16 rate periods. Under the 12 NCP methodology, we use the average of the NT customers' monthly non-coincidental peak load forecasts for the rate period. The monthly non-coincidental peak load forecast reflects the customer's load at its network load points of delivery (POD) on the hour of the month in which the sum of the customer's load at all of its points of delivery is highest (customer peak).

Q. In BP-14, the Administrator concluded that allocating costs to PTP and IR customers based on contract demand and to NT customers based on load was most consistent with cost causation, as reflected in BPA's planning approach. Is this still the case?

A. Yes. BPA's investment in the transmission system is in large part determined by BPA's obligation to plan the system to satisfy customers' contractual rights and to ensure that BPA has the capacity necessary to reliably serve peak loads under a range of projected system conditions. Administrator's Final Record of Decision, BP-14 Power and Transmission Rate Proceeding, BP-14-A-03 (July 2013), at 146 (BP-14 ROD). For PTP and IR customers, BPA's planning obligation is based on contract demand (or reserved capacity), which is the amount of capacity the customer has reserved to deliver energy from point(s) of receipt to point(s) of delivery. *Id*. Since PTP service is flexible (the customer has the right to resell, assign, and redirect transmission service during hours when its contract demand exceeds its needs), BPA's planning obligation is to ensure that it has sufficient capacity for customers to flexibly use their reserved capacities consistent with their contracts. *Id*. For NT customers, BPA's planning obligation is load-based, and BPA must plan the transmission system to serve each NT customer's peak loads, including forecast load growth from the customer's designated network resources. *Id*.

Q. Did you consider additional principles to support your cost allocation proposal?

A. Yes. In addition to being consistent with cost causation, using the 12 NCP method for the BP-18 rate period provides rate continuity. Rate continuity is important because BPA is considering whether to provide a one-time opportunity for NT and PTP customers to change OATT services (*i.e.*, change from PTP to NT or change from NT to PTP). If BPA provides customers with this opportunity, a stable and predictable rate design will allow BPA and customers to calculate the associated rate and cost impacts. Understanding these impacts will be an important consideration for BPA's determination of whether to provide the opportunity to change services.

Q. Why do you propose to allocate costs to NT customers based on the average of the 12 monthly peaks per year rather than a single annual peak or a limited number of monthly peaks?

A. We allocate costs to NT customers on the basis of 12 months, rather than a single month or several months, because this is consistent with BPA's planning approach. BPA plans and maintains the transmission system to reliably meet demands under a range of system conditions during peak and off-peak periods of the year. The Administrator relied on this reasoning in adopting the 12 NCP method for network cost allocation in the BP-14 ROD. *Id.* at 162-64. Meeting customers' demands during peak and off-peak conditions throughout the year impacts the costs BPA incurs. *Id*.

Q. Why do you propose to use an NCP forecast that reflects the NT customer's peak?

A. We use a monthly load forecast that reflects the NT customer's peak, rather than summing the peak load at each of the NT customer's points of delivery, because this reduces the likelihood that load could be double-counted.

Q. How does your proposal reduce the likelihood that the load forecast could double count load?

A. As explained in the rates study, we forecast NT loads using historical metering data. Transmission Rates Study and Documentation, BP-18-E-BPA-08, § 2.2.1.1. The historical metering data indicates the hour in which load peaked at each POD and the actual load during that hour. *Id*. If a utility had taken a POD out of service during an hour covered by the historical data and shifted load to a different POD during that hour to maintain load service, the shifted load could have impacted the timing of the peak at the PODs and the actual load during the peaks. The historical metering data would not show that this impact was the result of a load shift. Instead, the historical data could include the shifted load in the peaks for both PODs. If we were to use a load forecast that summed up the peak load forecast for each customer's PODs, the load forecast would be too high because the shifted load would be counted twice. Our proposal helps remedy this problem because it forecasts the customer's load at the same moment in time (the customer's system peak) and therefore does not double-count load that may have been shifted between PODs during the historical forecast period.

Section 5: Rate Schedule Changes

Q. Are you proposing changes to the non-rate provisions of any of the rate schedules?

A. Yes, we are proposing clarifying changes to the description of the short-distance discount (SDD) in the PTP-18 rate schedules and to the Reservation Fee. We also are proposing minor changes to the Failure to Comply Penalty Charge and the rate schedule for

Reactive Supply and Voltage Control from Generation Sources. Section 3 of our testimony describes the proposal to modify the Southern Intertie (IS-18) rate schedule to reflect our intent to discount the hourly rate for south-to-north use. Finally, as discussed in the testimony regarding the proposed financial reserves policy, Harris *et al.*, BP-18-E-BPA-17, we have added provisions in the relevant rate schedules to specify that the Cost Recovery Adjustment Clause and the Reserves Distribution Clause will apply to service under those schedules.

Q. What changes are you proposing to the short-distance discount specified in the PTP-18 rate schedule?

A. We are proposing changes to clarify the description of the discount. The primary changes are: (1) removal of the reference to powerflow studies, which has caused some confusion; (2) removal of the requirement that the POD capacity reservation eligible for a SDD may be no larger than the POD capacity reservation; and (3) clarification as to how firm and non-firm redirects impact reservations receiving the discount.

Q. Why are you proposing to remove the reference to powerflow studies?

A. In most cases, BPA determines circuit miles based on the shortest distance between the point of receipt (POR) and POD. A powerflow study, which examines how power flows over transmission facilities, does not assist BPA in making a determination of circuit miles when BPA makes the determination based on shortest distance.

Q. Why are you proposing to remove the requirement that the POD capacity reservation eligible for an SDD may be no larger than the POD capacity reservation?

A. This language applied to multiple-to-multiple POR/POD reservations, where each POR and POD had its own reserved capacity specified by contract. BPA does not allow new multiple-to-multiple reservations and has been converting existing multiple-to-multiple reservations upon renewal to single POR/POD reservations so that there is a single reserved capacity amount contractually specified for each POR/POD combination. There are no multiple-to-multiple reservations currently receiving the SDD and will not be in the future. Thus, we are proposing to remove this language from the PTP-18 rate schedule.

Q. Why are you proposing to clarify how redirects of reservations receiving the SDD are treated?

A. Prior rate schedules referred to all redirects (firm and non-firm) as requests to "secondary Points of Receipt (POR) and Points of Delivery (POD)." This language could potentially be interpreted incorrectly as applying only to non-firm redirects. Thus, we are proposing the change to this reference to specifically clarify that if a customer redirects on a firm or non-firm basis, it is not eligible to receive the discount for that month.

Q. Do any of the proposed changes to the short-distance discount substantively change how BPA applies the discount today as described above?

A. No. The proposed changes clarify the rate schedule language.

Q. What are the proposed changes to the General Rate Schedule Provisions (GRSPs) for the Reservation Fee?

A. The proposed changes to the Reservation Fee in the GRSPs help clarify the amount of the fee and the deadline of the required payment. We are not proposing any substantive changes to the Reservation Fee or how the fee is implemented.

Q. What changes are you proposing to the rate schedule for Reactive Supply and Voltage Control from Generation Sources?

A. We are proposing a minor clarification to the language that currently provides that the rates will be calculated for each quarter, and we are specifying that the rates will be posted on BPA's website and updated as needed. The rate for generation supplied reactive service has been zero since TR-08, and BPA expects the rate to remain at zero in the FY 2018–19 rate period. The proposed changes to the rate schedule require BPA to update the rate posted on the website only if the rate changes.

Q. How are you proposing to change the Failure to Comply Penalty Charge?

A. The current (FY 2016–2017) Failure to Comply Penalty Charge provides a mechanism to charge a customer for costs that BPA incurs as a result of the customer's failure to comply with a BPA order, including the costs of monetary penalties imposed on BPA for violation of reliability standards as a result of the failure to comply. GRSP II.B.3. Since BPA first included that language in the rate schedule, the U.S. Court of Appeals for the District of Columbia Circuit held that monetary penalties cannot be imposed on Federal entities such as BPA for violations of reliability standards. BPA is proposing to remove the language about monetary penalties from the rate schedule for this reason. In addition, BPA has never incurred costs from alternative measures it takes to maintain reliability following a failure to comply with a BPA order. Because the incurrence of these costs is so unlikely, BPA proposes to remove this language from the rate schedule.

Q. Does this conclude your testimony?

A. Yes.

Appendix A
Southern Intertie Hourly Rate Design Charts

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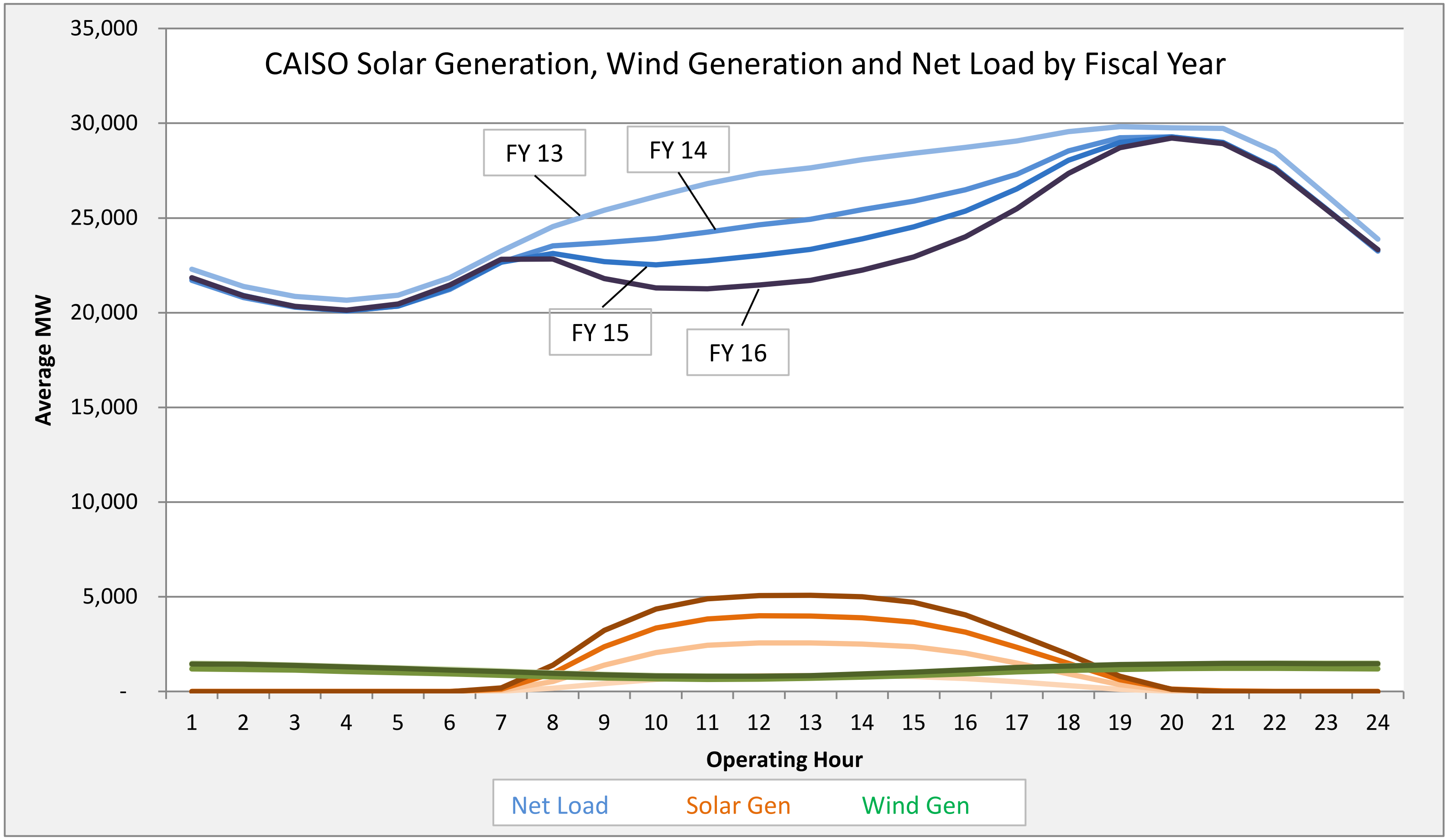
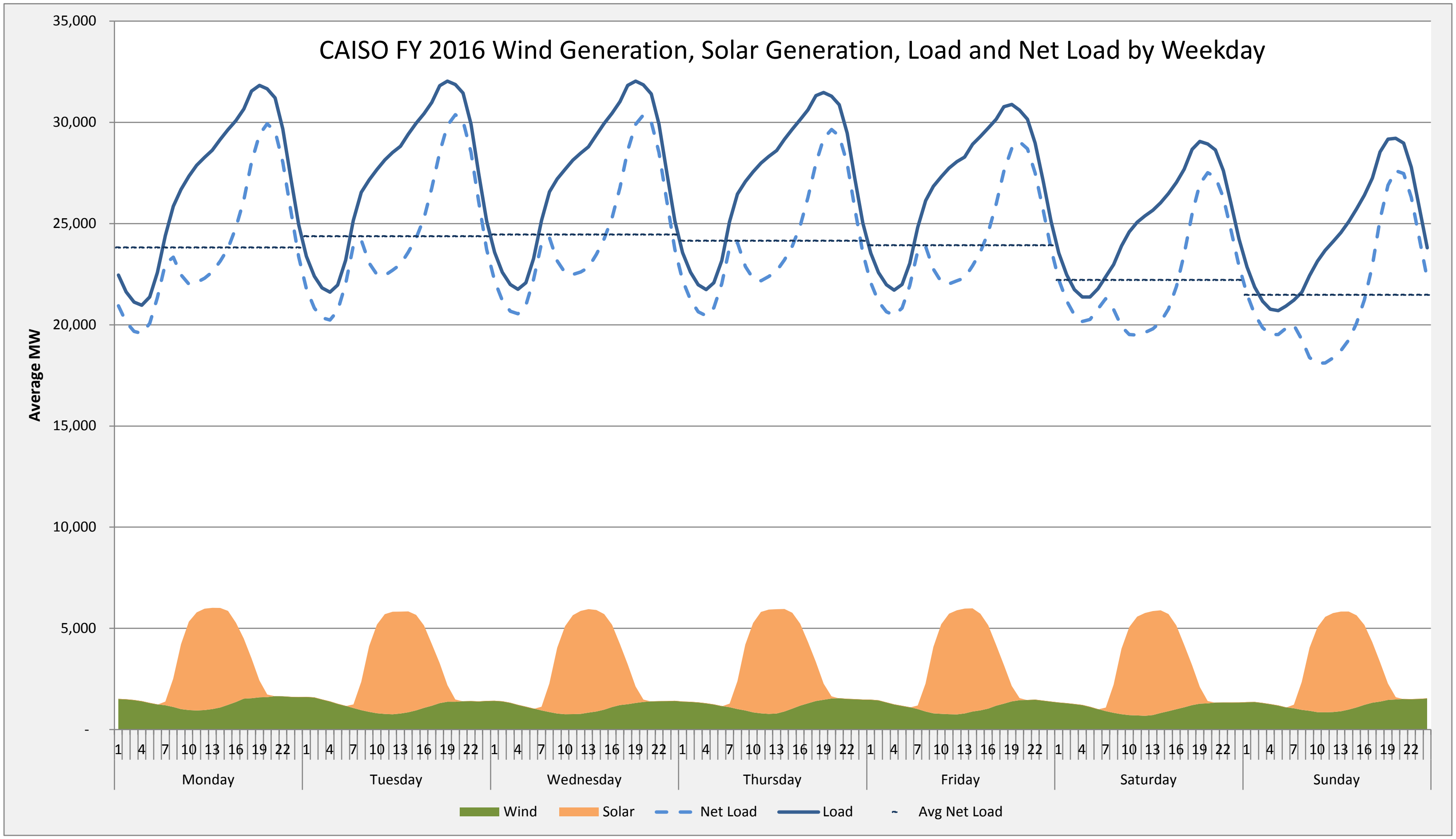
Chart 1: CAISO Solar Generation, Wind Generation and Net Load by Fiscal Year



Description

Annual average of net load, wind and solar by fiscal year and operating hour.
Due to data availiability FY 13 does not include October - December.

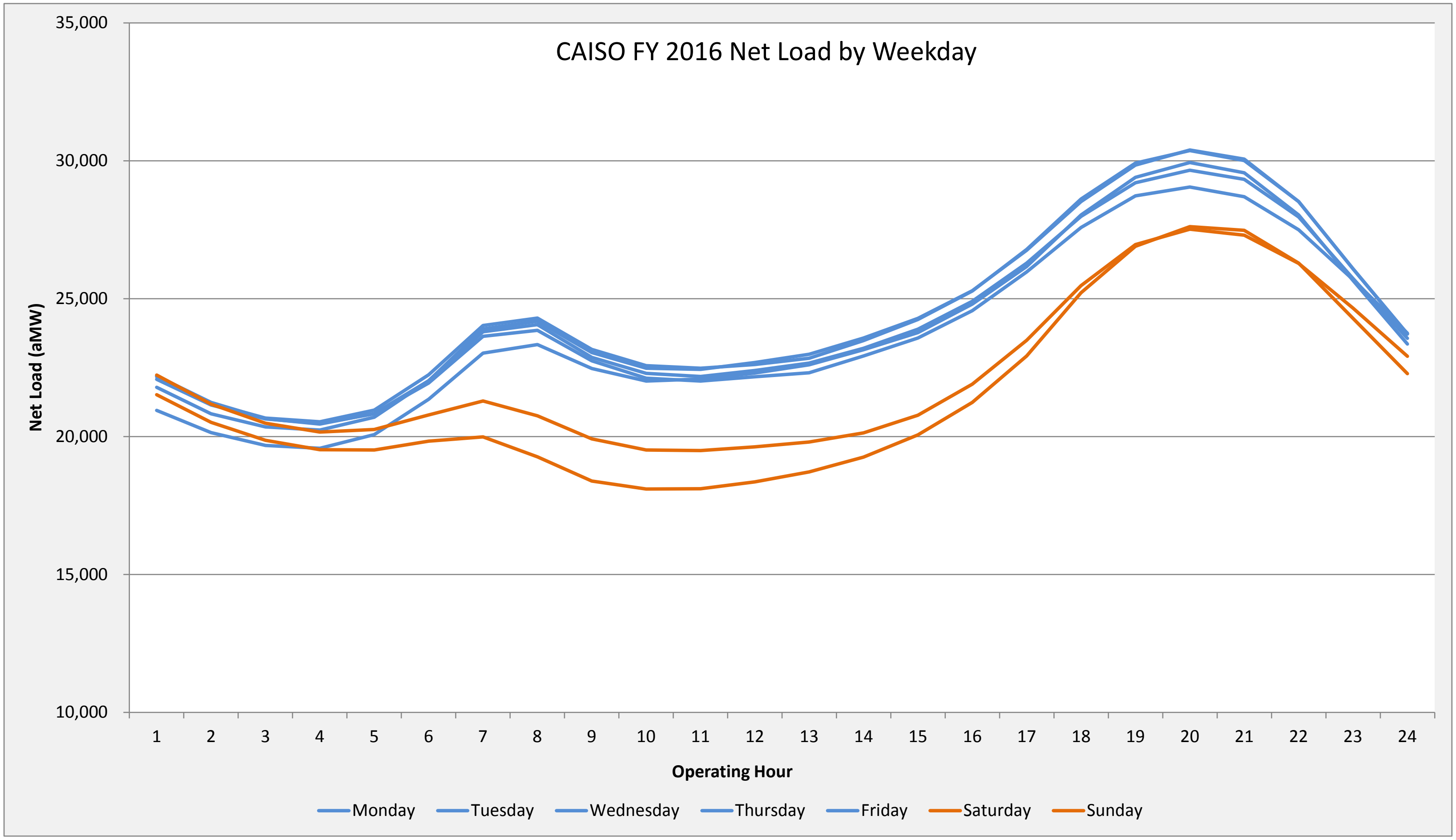
Chart 2: CAISO FY 2016 Wind Generation, Solar Generation, Load and Net Load by Weekday



<u>Description</u>

FY 2016 average of load, net load, wind and solar by weekday and operating hour.

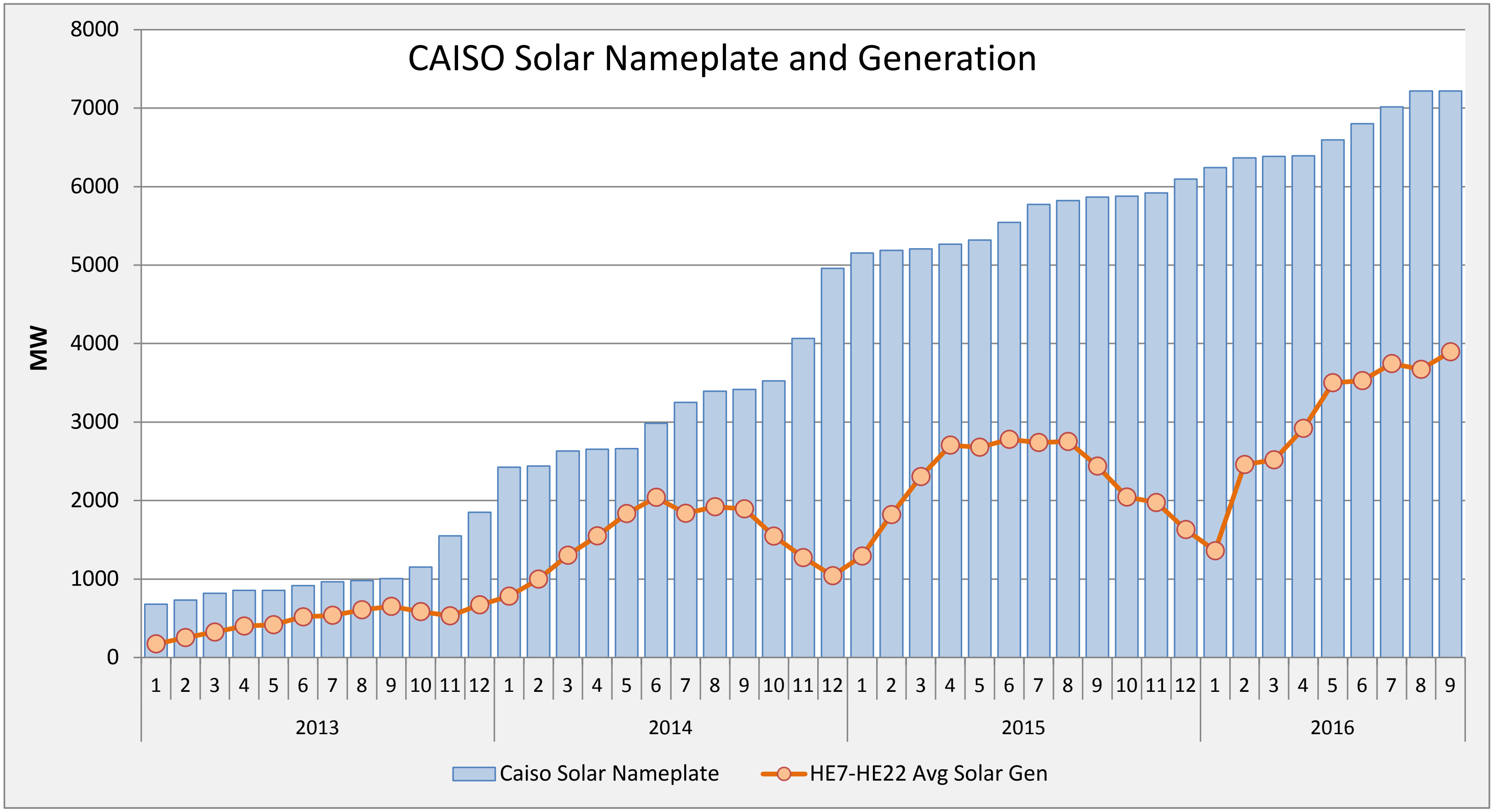
Chart 2.1: CAISO FY 2016 Net Load by Weekday



Description

FY 2016 average of net load by weekday and operating hour.

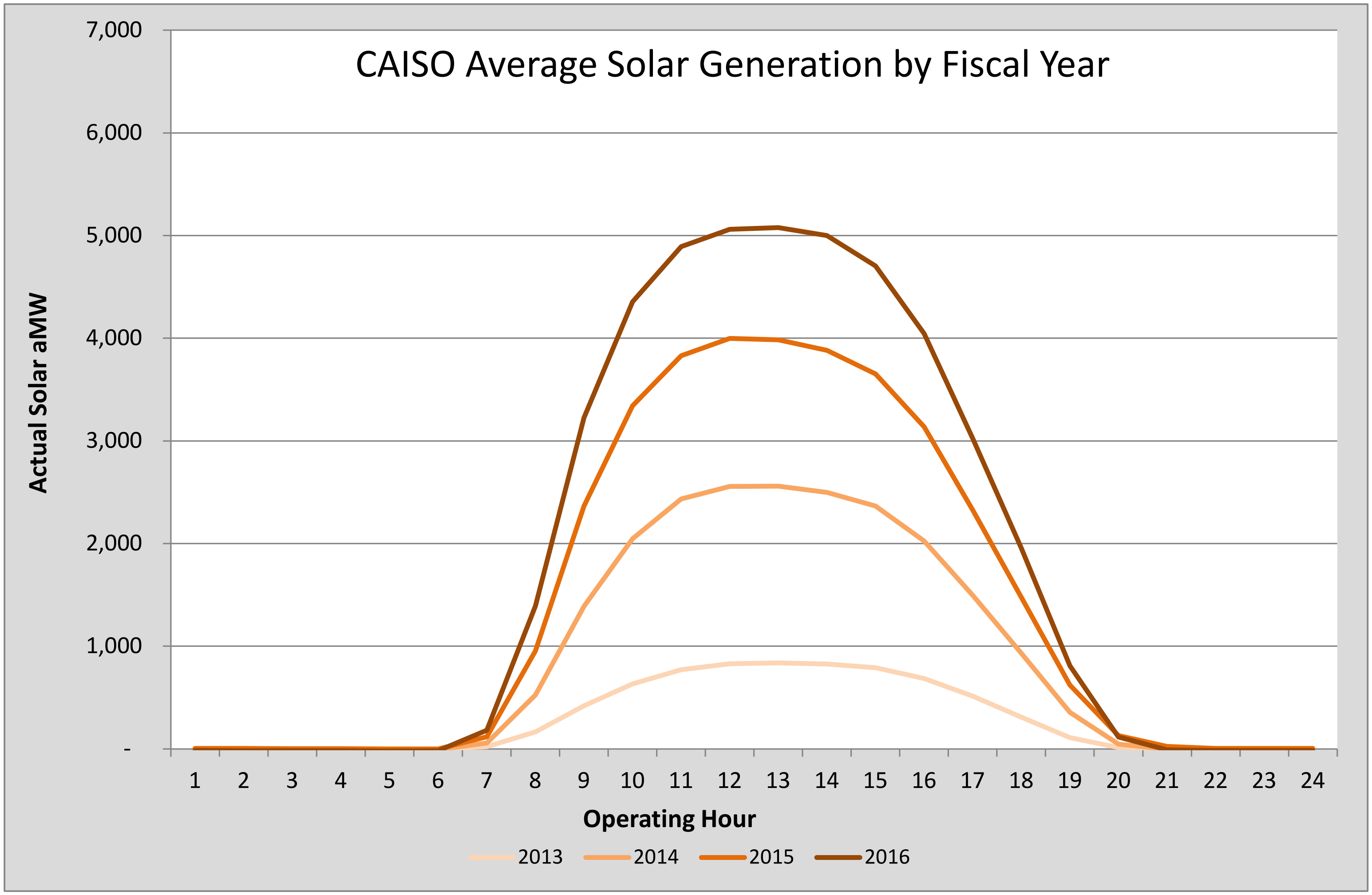
Chart 3: CAISO Solar Nameplate and Generation



Description

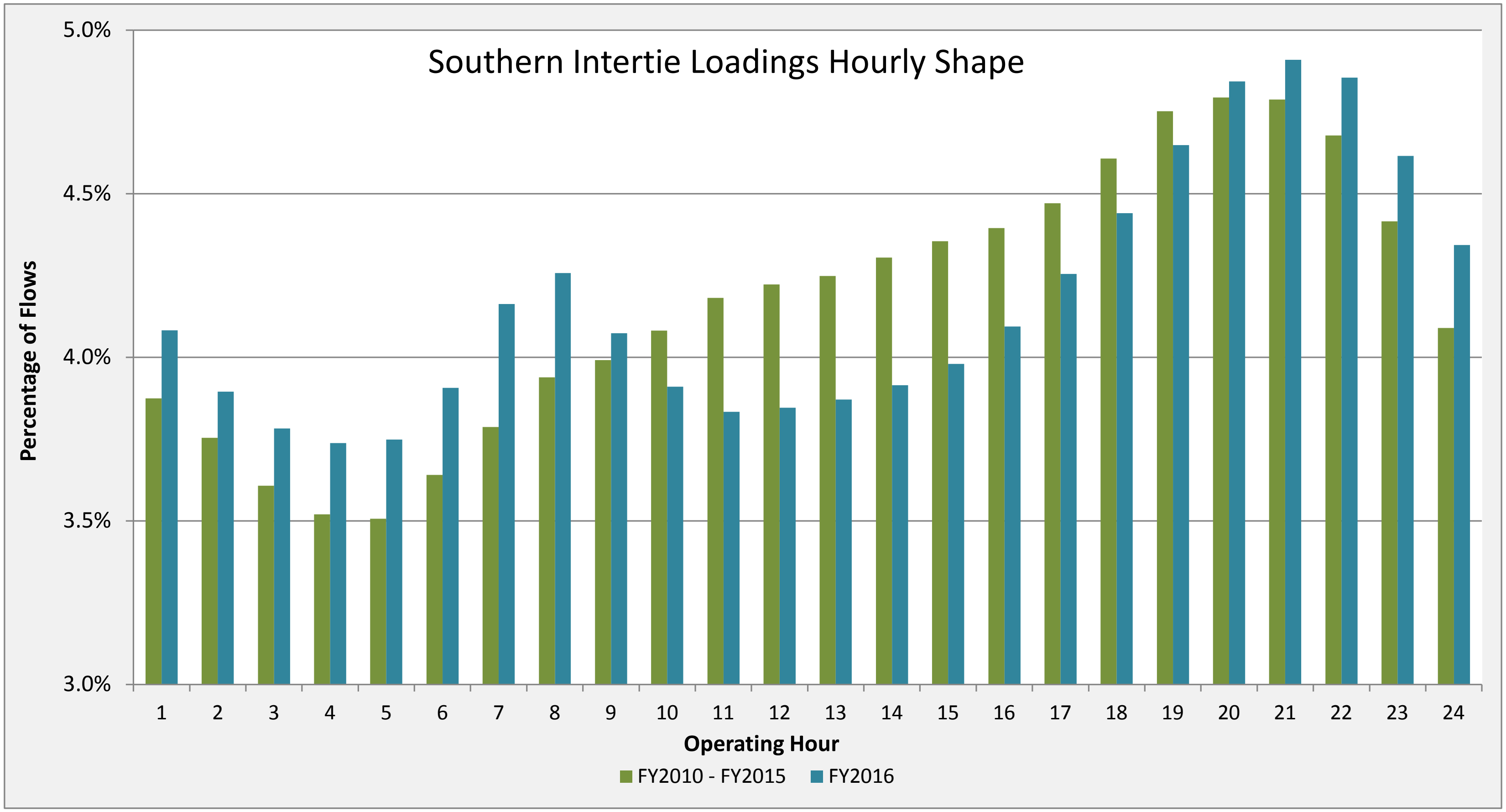
CAISO Solar Nameplate and heavy load hour solar generation by month

Chart 4: CAISO Average Solar Generation by Fiscal Year



Description
CAISO Solar Generation by fiscal year.

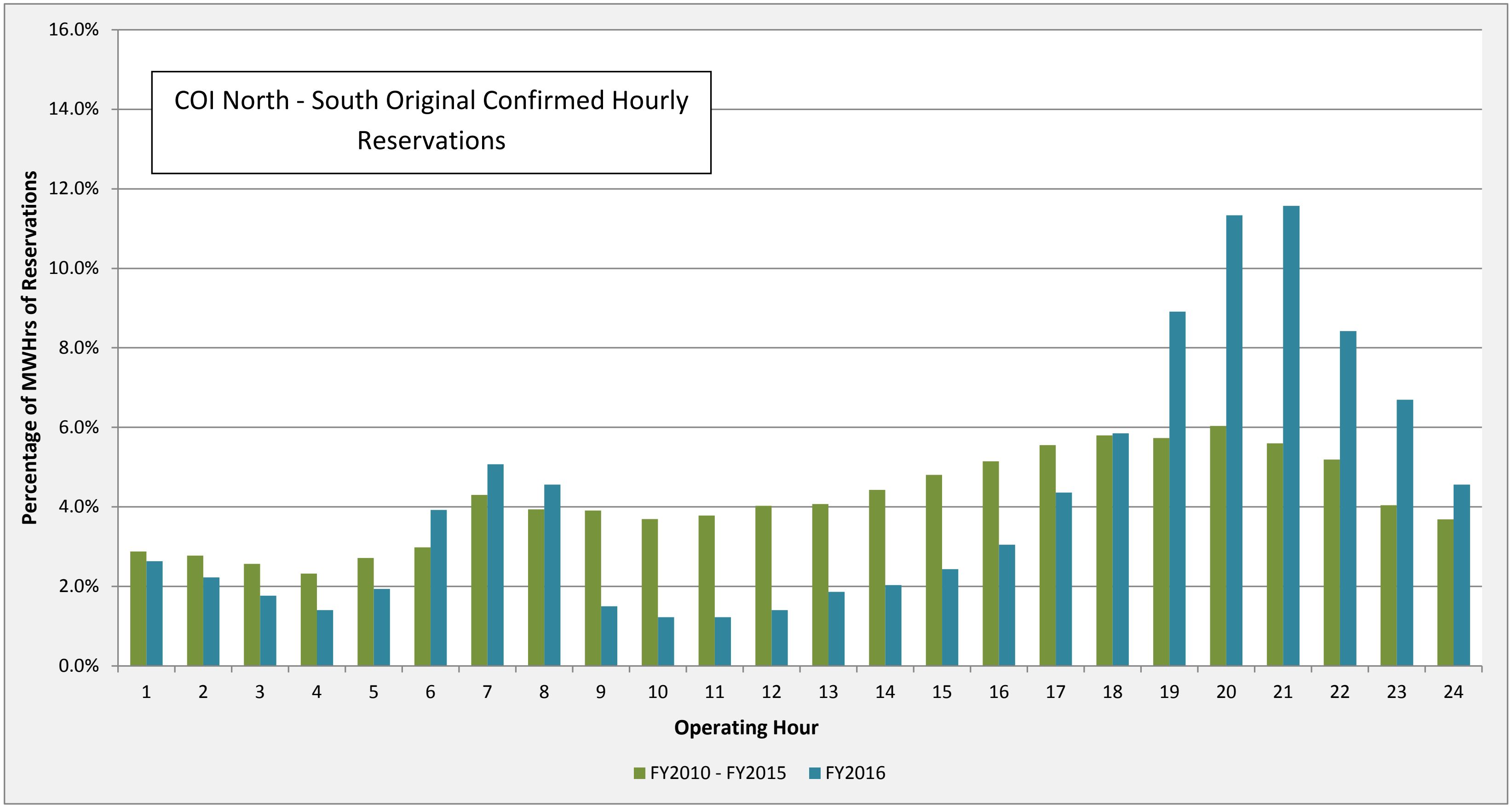
Chart 5: Southern Intertie Loadings Hourly Shape



Description

Hourly shape of Southern Intertie Loadings by operating hour.

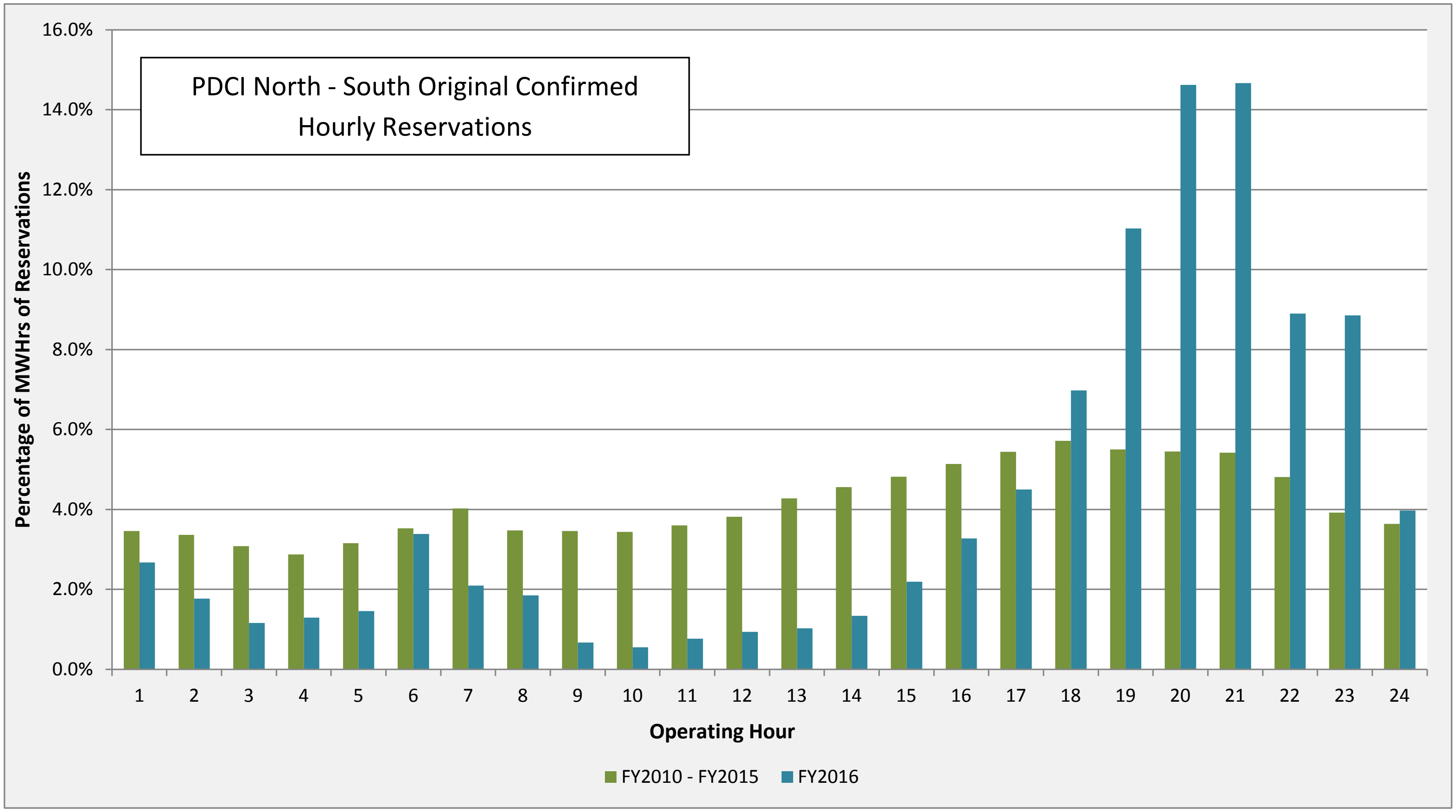
Chart 6: COI North to South Original Confirmed Hourly Reservations



Description

Hourly shape of Southern Intertie north to south hourly reservations by operating hour.

Chart 7: PDCI North to South Original Confirmed Hourly Reservations



Description

Hourly shape of Southern Intertie north to south hourly reservations by operating hour.