California Independent
System Operator Corporation

California ISO

Report on day-ahead market competitiveness: For September 25, 2019

October 30, 2019

Prepared by: Department of Market Monitoring

Executive summary

This report provides information on the competitiveness of the ISO's day-ahead market on September 25, 2019. The report was produced in response to market participant requests for the ISO to provide more transparency on the competiveness of day-ahead market outcomes on relatively high priced days. Key findings in this report include the following:

- Prices in the ISO's day-ahead market on September 25 equated to implied heat rates ranging from 25.35 to 28.86 MMBtu/MWh for the PG&E and SCE areas during hours ending 19 and 20.
- Day-ahead prices in the ISO's day-ahead market on this day were substantially above both fifteen minute and bilateral prices.
- On this date, bid in load increased relative to two days prior, while overall supply offered decreased, particularly from wind resources and virtual supply bids.
- Structural measures of market power indicate that the market was uncompetitive during hours 19 and 20 on September 25.
- A significant portion of supply from gas-fired resources offered by net sellers was bid at prices significantly above cost-based default energy bids used when local market power mitigation is triggered. Most supply from gas resource offered by load serving entities was offered at prices at or below default energy bids.
- About 5,000 MW of offered gas capacity did not clear the market. Much of this capacity was shown as resource adequacy and some was offered at costs below system marginal energy cost.
- The average price-cost markup was 4.4 percent on this date, calculated across all hours in all DLAPs.

The analysis that each of these observations is based on is presented in the following sections:

- Market prices
- Structural market power measures
- Conduct: Bidding behavior
- Impact : Price cost mark-up

1 Market prices

This report provides information on the competitiveness of the ISO's day-ahead market on September 25, 2019, when relatively high electricity prices relative to natural gas prices occurred during several hours.

Figure 1.1 shows hourly wholesale electricity prices in each of the three largest load aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric). Prices in all three areas rose above $150/MWh for two hours (HE 19 and 20) on this date.

Gas commodity prices in the next-day market were $3.17/MMBtu at PG&E Citygate and $3.93/MMBtu at SoCal Citygate. Gas commodity prices in the same day market were $3.08/MMBtu at PG&E Citygate and $3.94/MMBtu at SoCal Citygate.

The greenhouse gas index on this date was $17.26/MtCO2e, equivalent to an additional $0.918/MMBtu for a default efficient natural gas resource.

The implied heat rate is calculated by dividing the wholesale electricity price by the total cost of natural gas for a specific location. DMM calculated the implied heat rate for the southern and northern parts of the ISO system using total gas costs based on the next-day prices at SoCal Citygate and PG&E Citygate, plus additional gas transportation costs and greenhouse gas emission credits.[1]

The implied heat rates greater than 25 MMBtu/MWh are shown in Table 1-1. For hour-ending 19, the implied heat rate was 28.86 and 27.03 MMBtu/MWh for the PG&E and SCE areas, respectively. For hour-ending 20, the implied heat was 27.11 and 25.35 MMBtu/MWh for the PG&E and SCE areas, respectively.

Table 1-1. Implied heat rates for the PG&E and SCE areas on September 25, 2019 (greater than 25 MMBtu/MWh)

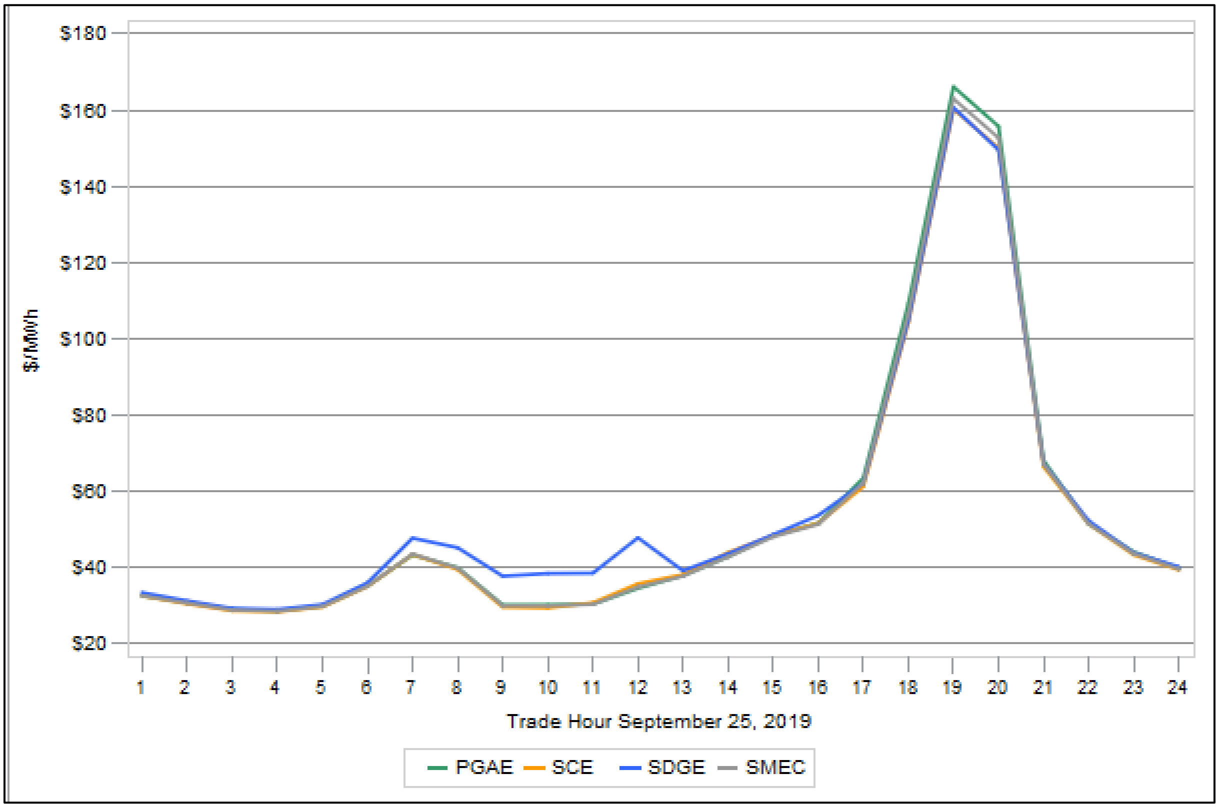
Hour	Location	Next-day gas commodity price ($/MMBtu)	Transportation cost ($/MMBtu)	Greenhouse gas emission credit ($/MMBtu)	DA LAP LMP ($/MWh)	Implied Heat Rate (MMBtu/MWh)
19	PG&E	$3.17	$1.57	$0.92	$166.10	28.864
19	SCE	$3.93	$0.95	$0.92	$160.22	27.028
20	PG&E	$3.17	$1.57	$0.92	$155.71	27.107
20	SCE	$3.93	$0.95	$0.92	$150.00	25.347

During these hours, day-ahead prices were substantially higher than prices in the ISO's 15-minute real-time and hourly real-time prices reported for regional bilateral hubs. Average hourly LAP prices in the ISO's 15 minute market ranged from $55-$63/MWh in hour ending 19 and from $115 to $124/MWh in hour ending 20. Hourly bilateral prices in the same hours at COB, Mid-Columbia, and Palo Verde ranged from $30/MWh to $51/MWh.

[1] For transportation costs, DMM used PGE2 and SCE3 as representative fuel regions for the PG&E and SCE areas, respectively. In addition, the analysis accounts for the non-fuel components of a unit's marginal cost by subtracting $2.80/MWh from the wholesale electricity price, which is the variable O&M cost for combined cycle units included in default energy bids used in bid mitigation.

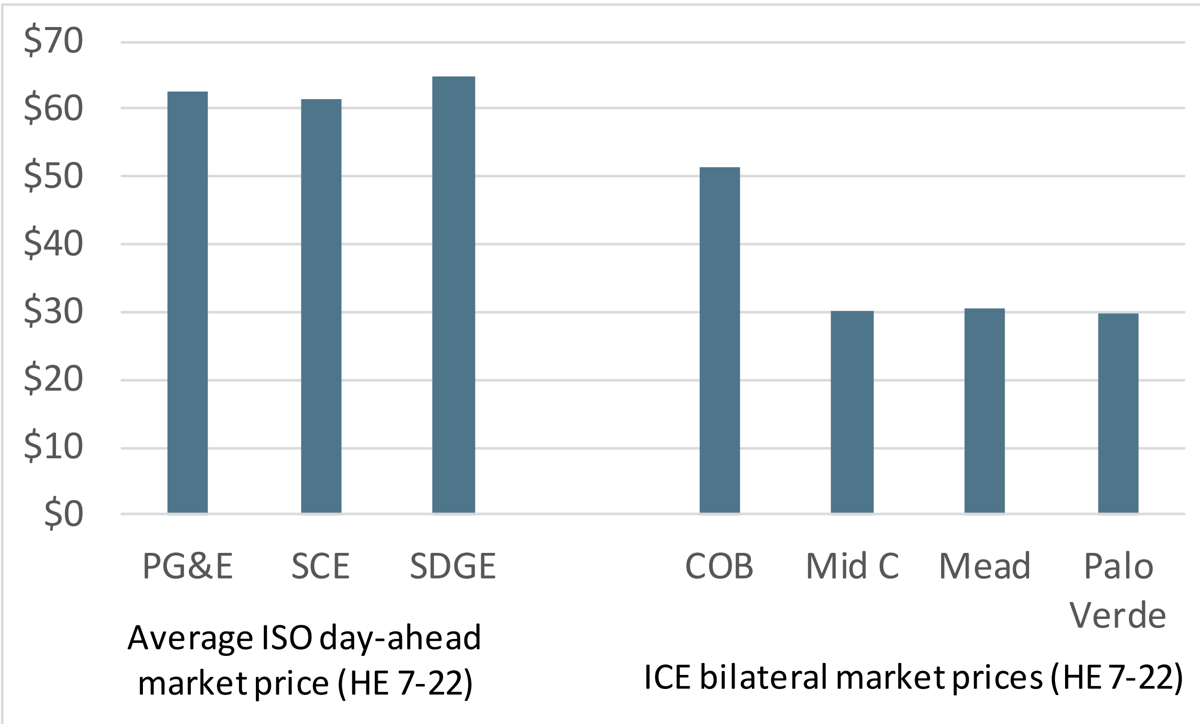
Average prices in the ISO's day-ahead market during peak hours (7 to 22) on September 25 were higher than prices for peak power in the day-ahead bilateral market at regional hubs. As shown in Figure 1-2, average prices in the ISO's day ahead market at the three major load aggregation points during peak hours ranged from abou5 \$62 to \$65/MWh. This compares to peak power prices of about \$51/MWh at COB and \$30/MWh at the other major trading hubs (Mid-Columbia, Mead and Palo Verde). Greenhouse gas compliance accounts for only \$7.39 of the \$32 to \$35 dollar difference.[2]

Figure 1-1. Day-ahead prices, September 25, 2019



[2] Using the default emission factor of 0.428 MT CO_2e/MWh, the \$17.26 greenhouse gas index on this date converts to a \$7.387 cost of greenhouse gas compliance for unspecified sources.

Figure 1-2. CAISO day-ahead and bilateral prices (Peak hours ending 7-22)



2 Structural measures of market power

Market structure refers to the ownership of available supply in the market. The structural competitiveness of electric markets is often assessed using two related quantitative measures: the *pivotal supplier test* and the *residual supply index*. Both of these measures assess the sufficiency of supply available to meet demand after removing the capacity owned or controlled by one or more entities.

- **Pivotal supplier test**. If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal. This is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.
- **Residual supply index**. The residual supply index is the ratio of supply from non-pivotal suppliers to demand. A residual supply index less than 1.0 indicates an uncompetitive level of supply.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for oligopolistic bidding behavior. The potential for such behavior is high in the electric industry because the demand for electricity is highly inelastic, and competition from new sources of supply is limited by long lead times and regulatory barriers to siting of new generation.

In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as RSI1. With the two or three largest suppliers excluded, we refer to these results as RSI2 and RSI3, respectively.

The residual supply index values reflect load conditions, generation availability, and resource ownership or control. Some generating units have tolling contracts, which transfer the control from unit owners to load-serving entities. These tolling contracts improve overall structural competitiveness in the period.

The values presented below include several changes in how supply and demand may be measured when calculating the RSI which DMM believes may represent refinements in the methodology used by DMM in prior annual reports. These include:

- Use of *input bids* for physical generating resources (adjusted for outages and de-rates) instead of post-processed bids used in the final market software optimization (or *output bids*)
- Accounting for losses (typically increasing demand by 2 to 3 percent)
- Including self-scheduled exports as demand (combined with the day-ahead load forecast plus upward ancillary service requirements and transmission losses)
- Including ancillary services bids in excess of energy bids to account for this additional supply available to meet ancillary service requirements in the day-ahead market
- Exclusion of CPUC jurisdictional investor-owned utilities as potentially pivotal suppliers.
- Accounting for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits.
- As in prior DMM analyses, virtual bids are excluded.

Results of this analysis are provided in Table 2-1. The assumptions listed above represent what DMM believes is the most appropriate supply and demand inputs. As shown in Table 2-1, RSI2 and RSI3 values were slightly less than 1 in both hours.

Table 2-1. Residual supply index calculation September 25, 2019

	Hour-ending 19	Hour-ending 20
RSI1	1.041	1.051
RSI2	0.951	0.959
RSI3	0.890	0.897

3 Conduct

3.1 Demand and supply bids

Figures 3.1 and 3.2 compare the system level demand and supply curves for the ISO's day-ahead market in hour 19 on September 25, 2019 with the two prior weekdays. Figures 3-3 through 3-5 compare the supply curves for the ISO's day-ahead market in hour 19 with the two prior weekdays for three types of supply (imports, wind and virtual supply). In each of these charts, September 23 is shown in dark blue, September 24 in light blue and September 25 in red.

As shown in these charts, bid-in demand (load) increased on September 24 and was similar on the following day. In addition, overall supply decreased on September 25 compared to the prior days, particularly from imports, wind and virtual supply.

Figure 3-1 Load bids (hour 19, September 23 - 25, 2019)

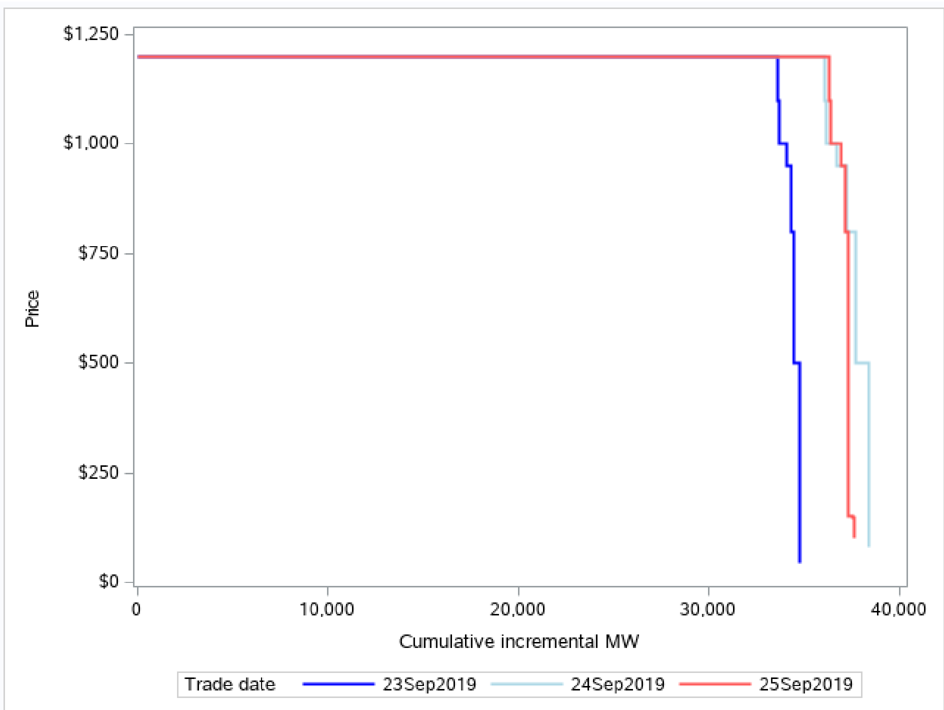


Figure 3-2 Supply bids (hour 19, September 23 - 25, 2019)

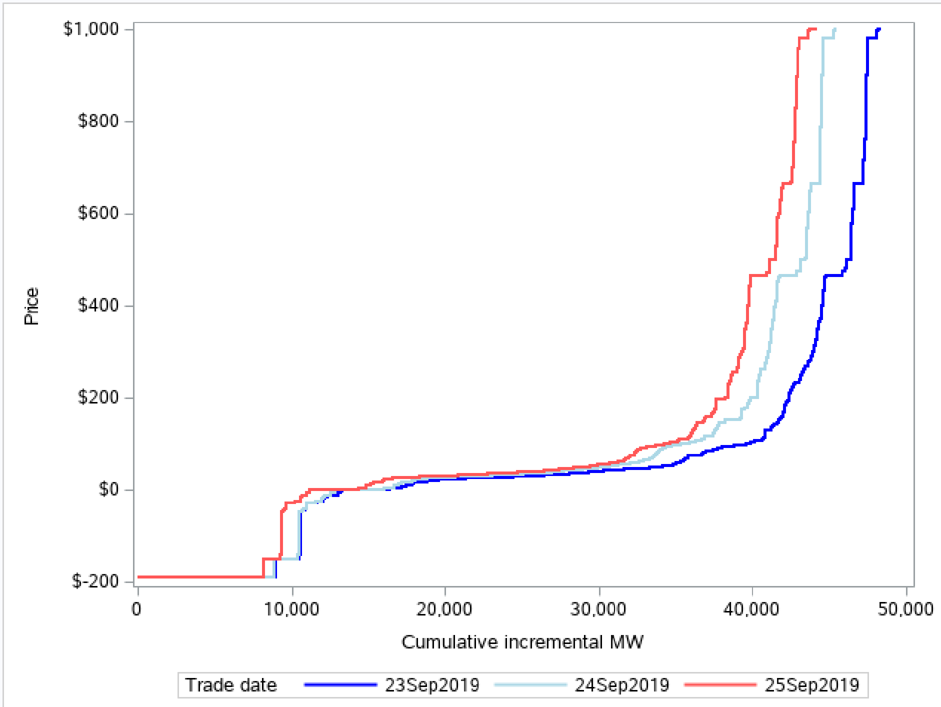


Figure 3-3 Import bids (hour 19, September 23 - 25, 2019)

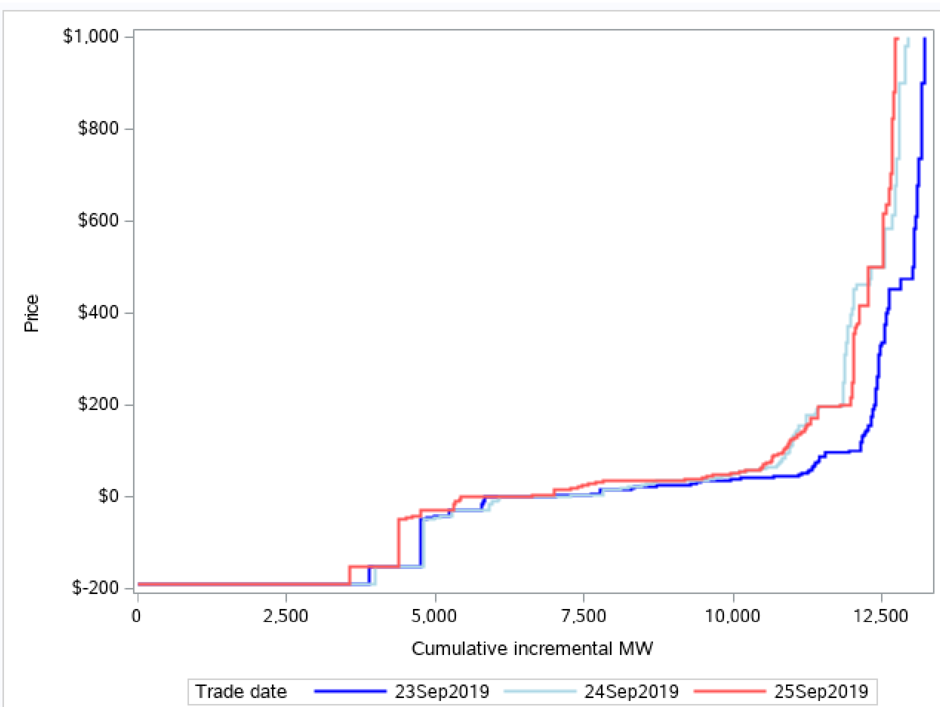


Figure 3-4 Virtual supply bids (hour 19, September 23 - 25, 2019)

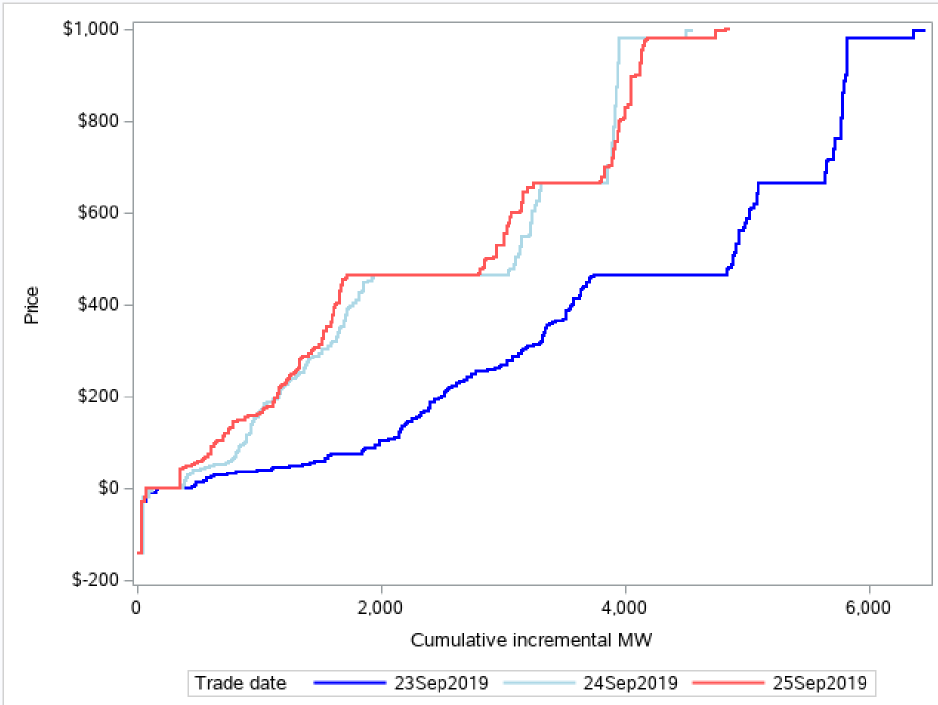
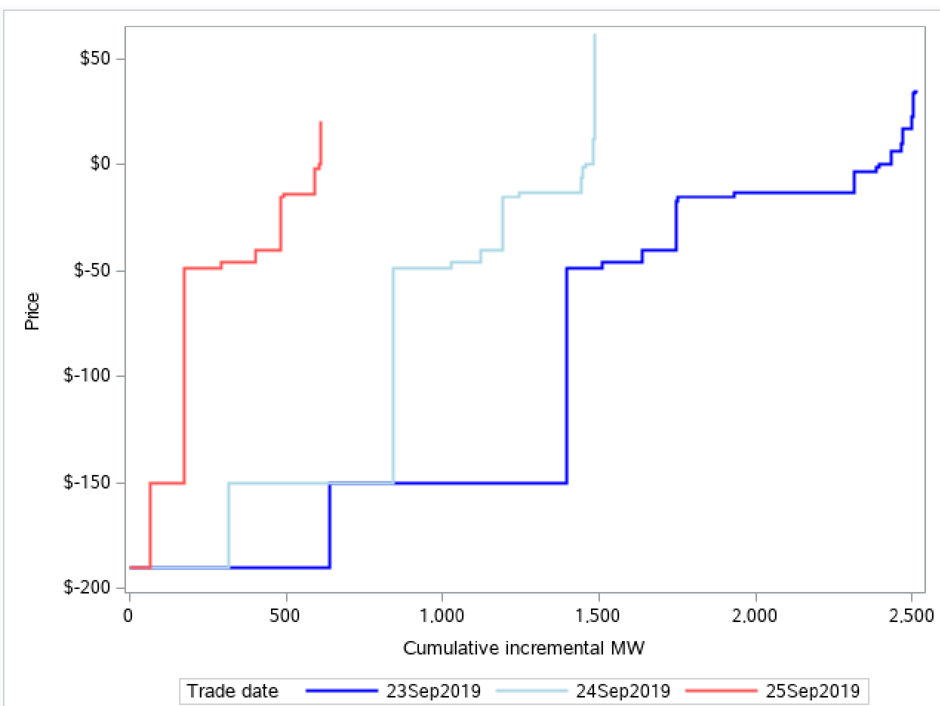


Figure 3-5 Wind supply bids (hour 19, September 23 - 25, 2019)



3.2 Competitiveness of bids for gas-fired units

One indicator of market competitiveness is the degree to which suppliers offer supply into the market at prices close to marginal cost. For this analysis, DMM uses default energy bids (or DEBs) for gas generation developed for use in local market power mitigation. These DEBs are based on each gas unit's estimated marginal cost plus a 10% adder.

The ISO's local market power mitigation provisions classify each supplier as either a net seller or a net buyer, based on purchases and sales over an extended period. Net buyers are not considered potentially pivotal in ISO markets as these suppliers are assumed to have no incentive to offer capacity into the market above marginal cost. As in the structural market power analysis presented above, DMM classifies any CPUC jurisdictional investor-owned utility as a net buyer due to least cost bidding requirements imposed on the state's IOUs by the CPUC.

Figure 3.6 compares energy bids submitted by participants to default energy bids for gas generation held by net buyers. The blue line shows supply energy bids for these resources in the day-ahead market for hour-ending 19 on September 25 of 2019.[3] The supply curve shown in green shows the default energy bids associated with each bid segment. Supply from net buyers is offered into the market at or below default energy bids. .

Figure 3.7 provides the same comparison for gas capacity held by net sellers in this hour. For net sellers, input bids are at or below default energy bids for the first approximately 4,000 MW segment of the curve, but exceed reference levels for the remaining 5,000 MW of supply. This difference in bidding behavior, which has been observed in other hours, is consistent with non-competitive conduct in the presence of market power.

[3] Supply curves depicted in these figures show the incremental amount for each bid segment and therefore do not account for the generation associated with the minimum operating levels of the resources. Self-scheduled generation is depicted on the charts at -$190/MWh for illustrative purposes.

Figure 3-6 Net buyers supply input bid and reference (hour 19, September 25)

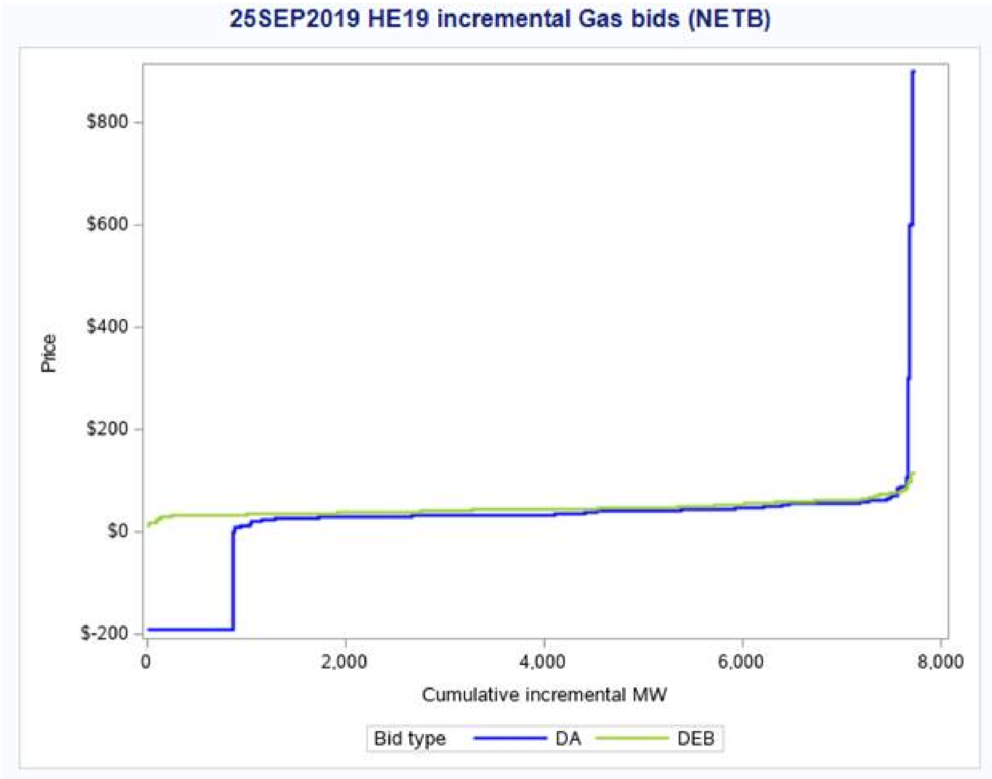
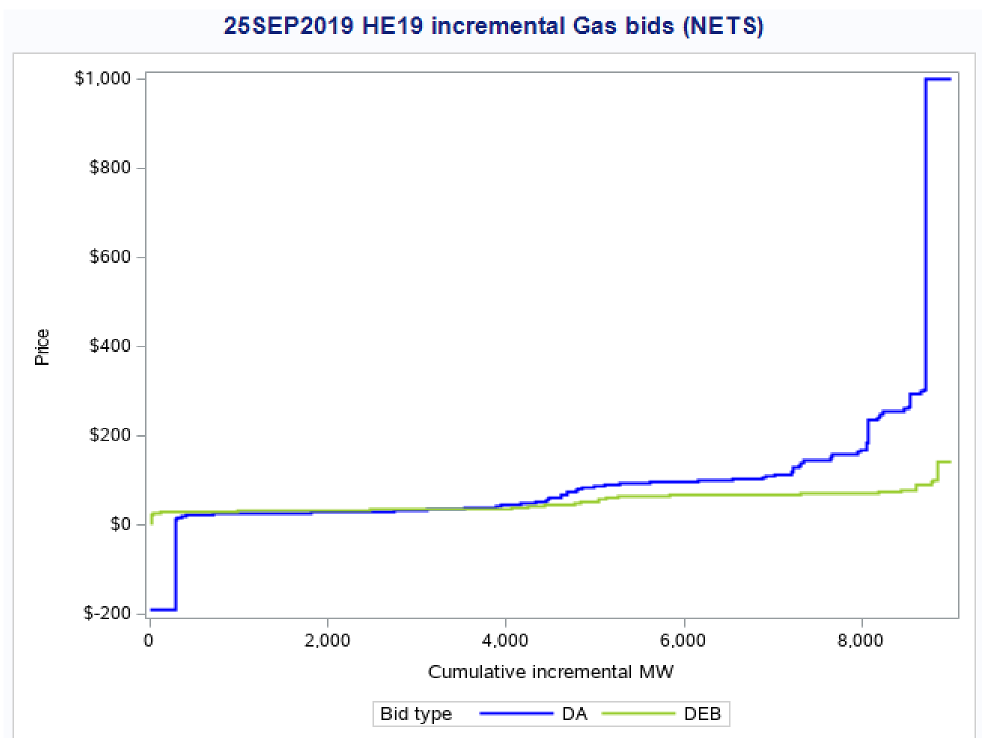


Figure 3-7 Net sellers supply input bid and reference (hour 19, September 25, 2019)



3.3 Uncleared capacity

Capacity bid into the market will not clear when bid above the clearing price. In addition, energy bids below nodal clearing prices may not be dispatched due to resource specific constraints including ramping and other inter-temporal constraints. Finally, the market will not dispatch energy bids from resources that are not committed by the market.

In one of the hours analyzed in this report (hour ending 19), almost 5,000 MW of gas capacity did not clear the day-ahead market. As indicated in Figure 3.8, most of this capacity was shown as resource adequacy capacity and almost 4,000 MW was offered at or below the system marginal energy cost shown in grey. This capacity may have failed to clear due to price differences caused by congestion or operational constraints on the resource (e.g., ramping) and the cost of committing these resources. There was no congestion significant enough to impact default load aggregation point prices on this date, so the second and third explanations are most likely.

As shown in Figure 3.9, over 3,000 MW of import bids failed to clear. Of this, the majority was not resource adequacy and approximately half was bid below the system marginal energy cost. All but 300 MW of this capacity was constrained by binding intertie constraints.

Figure 3-8 Uncleared incremental gas-fired capacity (Hour 19, September 25, 2019)

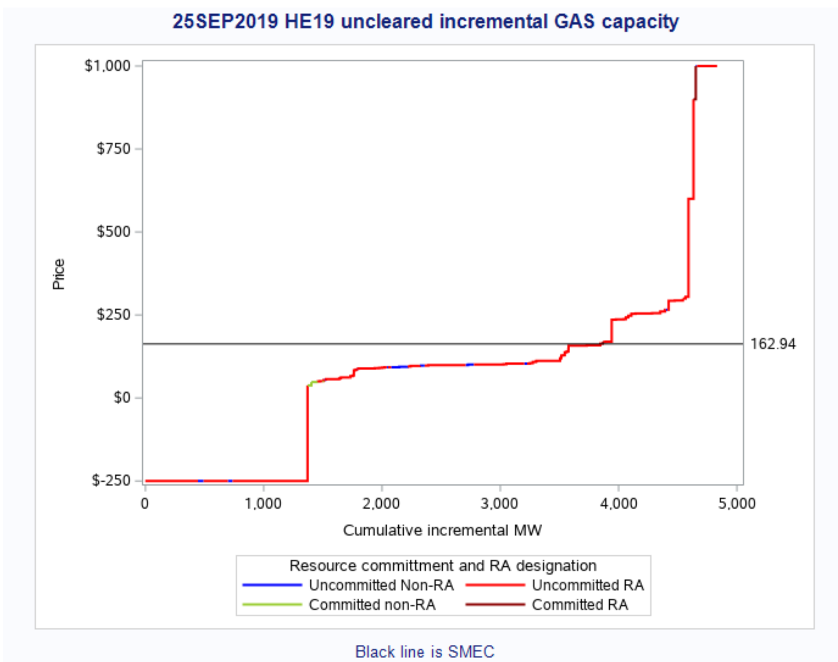
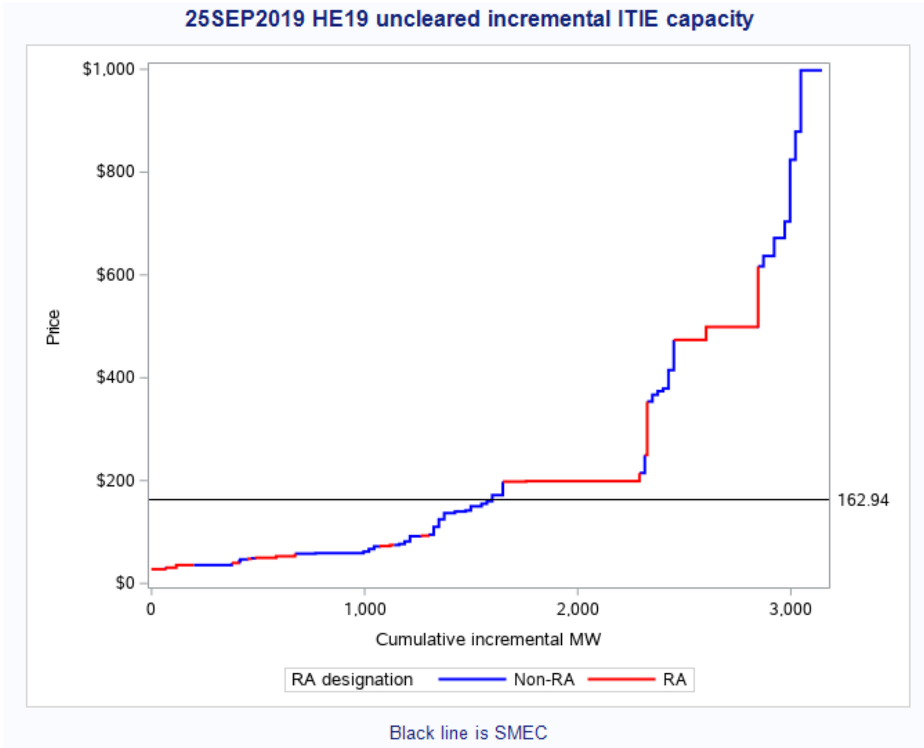


Figure 3-9 Uncleared incremental import capacity (Hour 19, September 25, 2019)



4 Day-ahead market software simulation

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market after replacing the market bids of all gas-fired units with the lower of their submitted bids or their default energy bids (DEB). This methodology assumes competitive bidding of price-setting resources and is calculated using DMM's version of the actual market software.

As shown in Figure 4.1 – 4.3, hourly prices in the day-ahead market were very similar to or slightly above the estimated competitive baseline prices in most hours, but below in hours 19 and 20. DMM calculates the day-ahead price-cost markup by comparing the competitive benchmark to the base case load-weighted average price for all energy transactions in the day-ahead market. Each figure presents the competitive scenario in blue and the base case price in green. The day-ahead market price is shown in yellow. Each market simulation is preceded by a base case rerun with all of the same inputs as the original market run before completing the benchmark simulation, to screen for accuracy.

The average price-cost markup was 4.4 percent on this date calculated across all hours in all DLAPs. The calculated markup in hour 19 and 20 ranged from $7.37 to $8.13. The calculated markup was highest in hour 18 in all DLAPs, over $16/MWh.

Figure 4-1 Comparison of competitive baseline with hourly day-ahead prices PG&E

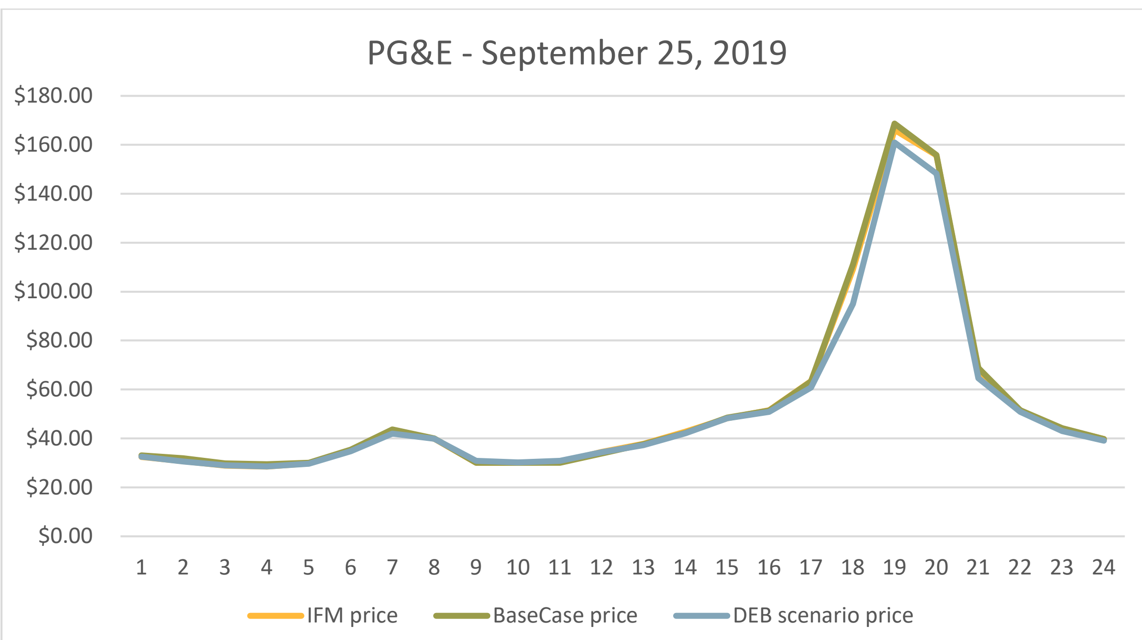


Figure 4-2 Comparison of competitive baseline with hourly day-ahead prices SCE

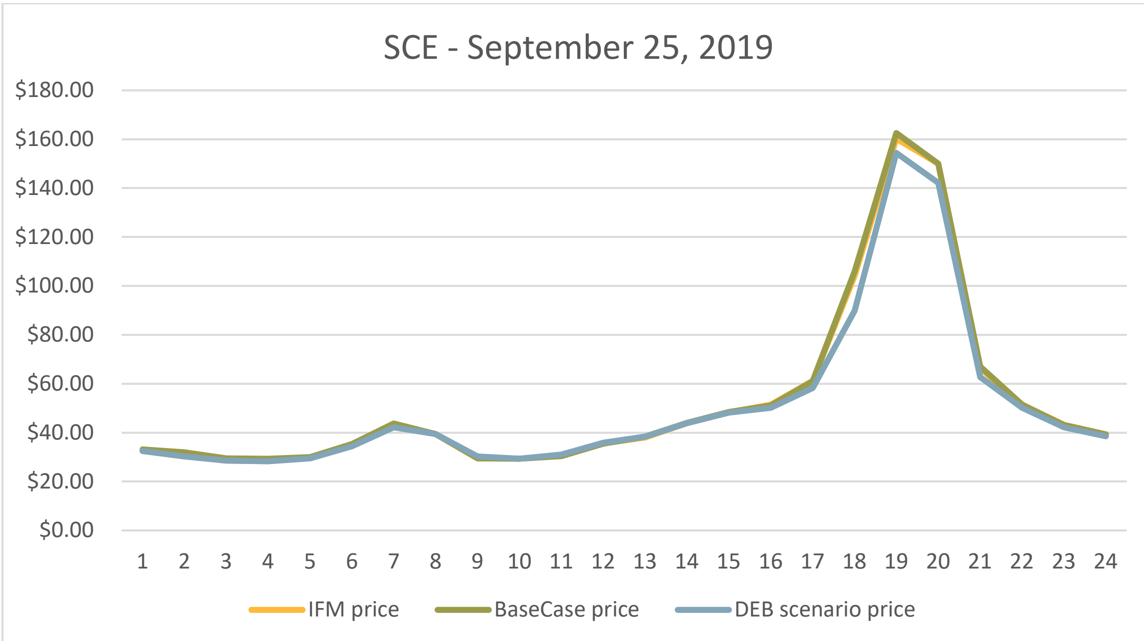


Figure 4-3 Comparison of competitive baseline with hourly day-ahead prices SDG&E