California Independent System Operator Corporation

California ISO

Report on day-ahead market competitiveness: For July 30-31, 2020

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Prepared by: Department of Market Monitoring

Executive summary

This report provides information on the competitiveness of the ISO's day-ahead market on July 30 and July 31, 2020. The report was produced in response to market participant requests for the ISO to provide more transparency on the competeiveness 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 July 30 and July 31 equated to implied heat rates of about 27 to 28 MMBtu/MWh in hour-ending 19 and about 37 to 39 MMBtu/MWh in hour-ending 20 for the SCE and SDG&E areas.
- SCE and SDG&E prices in the ISO's day-ahead market on these days were below corresponding bilateral prices at Mead and Palo Verde.
- On July 30 and 31, bid in load, exports, and virtual demand increased relative to the prior two days, while virtual supply offers decreased.
- Structural measures of market power indicate that the market was potentially uncompetitive during seven hours on July 30 and eight hours on July 31.
- 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.

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

- Market prices
- Structural market power measures
- Bidding behavior

1 Market prices

This report provides information on the competitiveness of the ISO's day-ahead market on July 30 and 31, 2020, when relatively high electricity prices relative to natural gas prices occurred during several hours.

Figure 1-1 and Figure 1-2 show hourly wholesale electricity prices in each of the three largest load aggregation points (LAPs) in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) for July 30 and July 31, 2020. Prices in the Southern California Edison and San Diego Gas and Electric areas rose above $200/MWh on both of these days for hour-ending 20.

Gas commodity prices in the next-day market were $2.60/MMBtu at SoCal Citygate for both of these days. Gas commodity prices in the same day market at SoCal Citygate were $2.61/MMBtu on July 30 and $2.55/MMBtu on July 31.

The greenhouse gas index on these days were around $17.01/MtCO2e, equivalent to an additional $0.90/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 separately for PG&E, SCE, and SDG&E using 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 roughly 27 to 28 MMBtu/MWh for the SCE and SDG&E areas. For hour-ending 20, the implied heat rate was roughly 37 to 39 MMBtu/MWh for the SCE and SDG&E areas.

Table 1-1. Implied heat rates by LAP area on July 30-31, 2020 (greater than 25 MMBtu/MWh)

Date	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)
30-Jul	19	SCE	$2.60	$2.59	$0.91	$171.65	27.71
	19	SDG&E	$2.60	$2.88	$0.91	$173.42	26.74
	20	SCE	$2.60	$2.59	$0.91	$243.10	39.43
	20	SDG&E	$2.60	$2.88	$0.91	$245.23	37.99
31-Jul	19	SCE	$2.60	$2.59	$0.90	$173.50	27.97
	19	SDG&E	$2.60	$2.88	$0.90	$175.12	26.97
	20	SCE	$2.60	$2.59	$0.90	$237.05	38.38
	20	SDG&E	$2.60	$2.88	$0.90	$238.74	36.92

[1] For transportation costs, DMM used the maximum fuel region specific to each area. 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.

Figure 1.1. Day-ahead prices, July 30, 2020

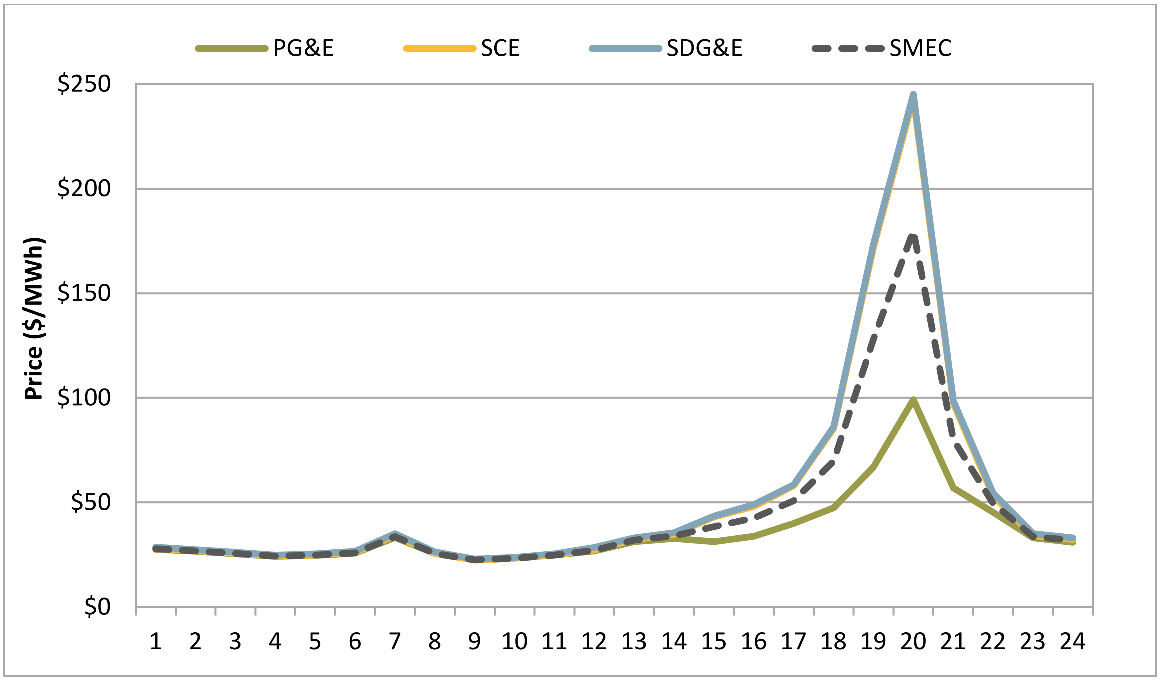
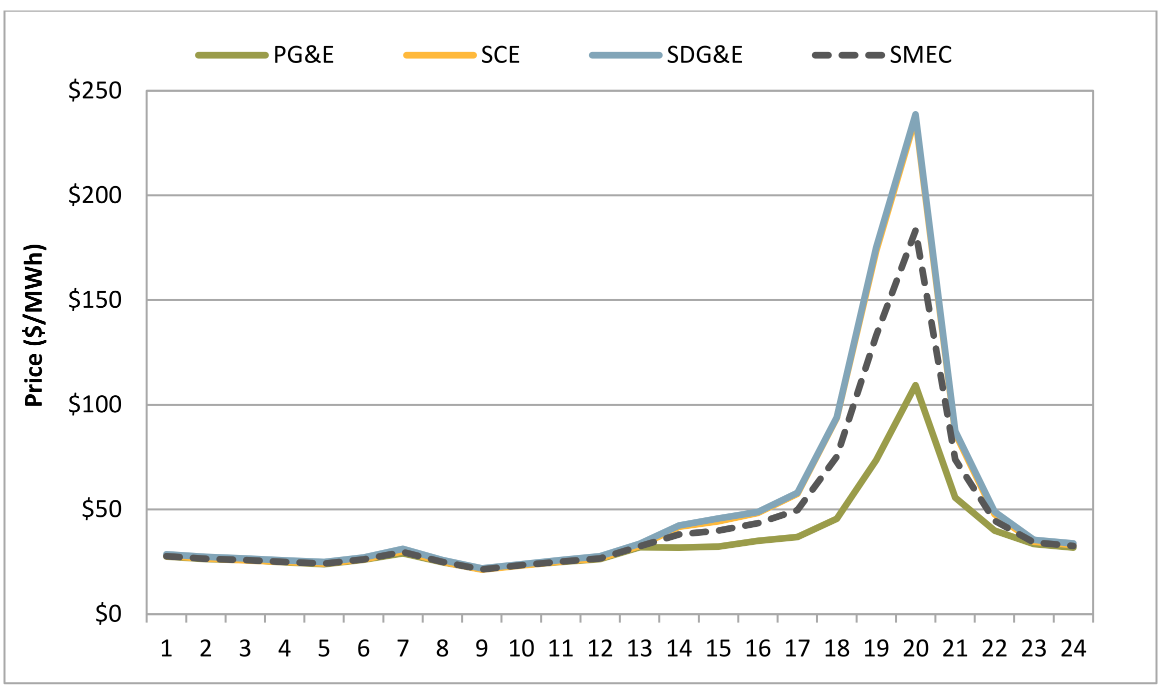
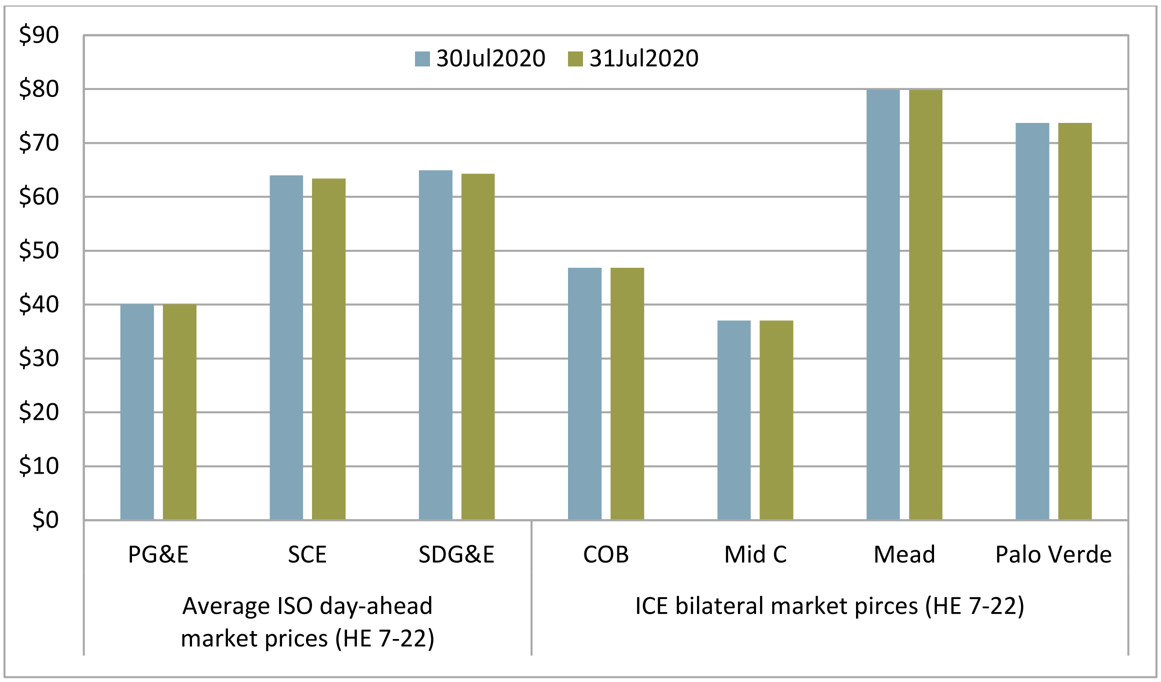


Figure 1.2. Day-ahead prices, July 31, 2020



As shown in Figure 1-3, average day-ahead market prices during peak hours (7 to 22) at the SCE and SDG&E load aggregation points were lower than prices for peak power in the day-ahead bilateral market at the Mead and Palo Verde hubs on both July 30 and July 31, 2020. Average prices for SCE and SDG&E for these hours was around $64/MWh on these days. This compares to peak power prices of about $80/MWh at Mead and $74/MWh at Palo Verde.

Figure 1.3. 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, there were many hours with RSI1, RSI2, and RSI3 values less than 1 on both days.

Table 2-1. Residual supply index calculation July 30-31, 2020

Date	Hour	RSI1	RSI2	RSI3
30-Jul	17	1.13	1.027	0.971
	18	1.077	0.977	0.921
	19	1.012	0.91	0.855
	20	0.969	0.864	0.807
	21	0.996	0.888	0.828
	22	1.041	0.925	0.862
	23	1.19	1.059	0.988
31-Jul	16	1.149	1.052	0.996
	17	1.134	1.038	0.984
	18	1.089	0.994	0.94
	19	1.031	0.936	0.882
	20	0.988	0.89	0.834
	21	1.021	0.918	0.859
	22	1.078	0.968	0.906
	23	1.186	1.064	0.996

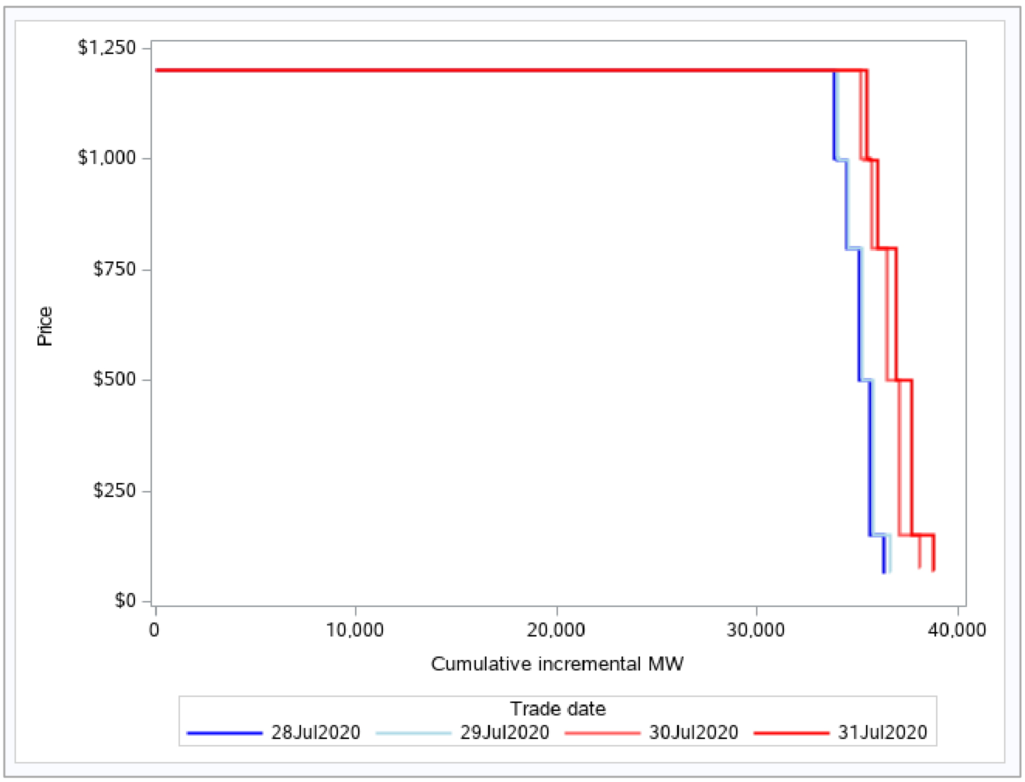
3 Conduct

3.1 Demand and supply bids

Figures 3-1 and 3-8 compare the system level demand and supply curves for the ISO's day-ahead market in hour 20 between July 28 and July 31, 2020[2].

As shown in these charts, bid-in demand (load), exports, and virtual demand all increased on July 30 and July 31 relative to the two prior days. Further virtual supply offers on July 30 and 31 decreased significantly. Imports offered on July 30 were lower than on July 31. Both self-scheduled and economic export bids increased, consistent with higher bilateral prices outside of the ISO.

Figure 3.1 Load bids (hour 20, July 28 - 31, 2020)



[2] 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 3.2 Supply bids (hour 20, July 28 - 31, 2020)

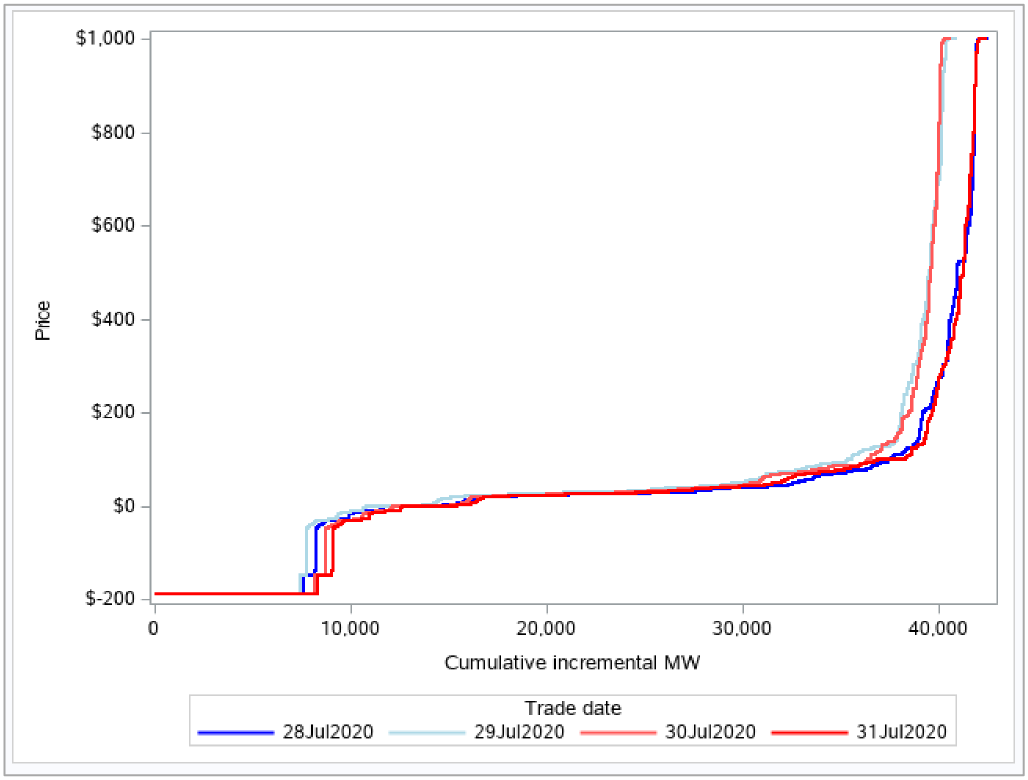


Figure 3.3 Generation bids (hour 20, July 28 - 31, 2020)

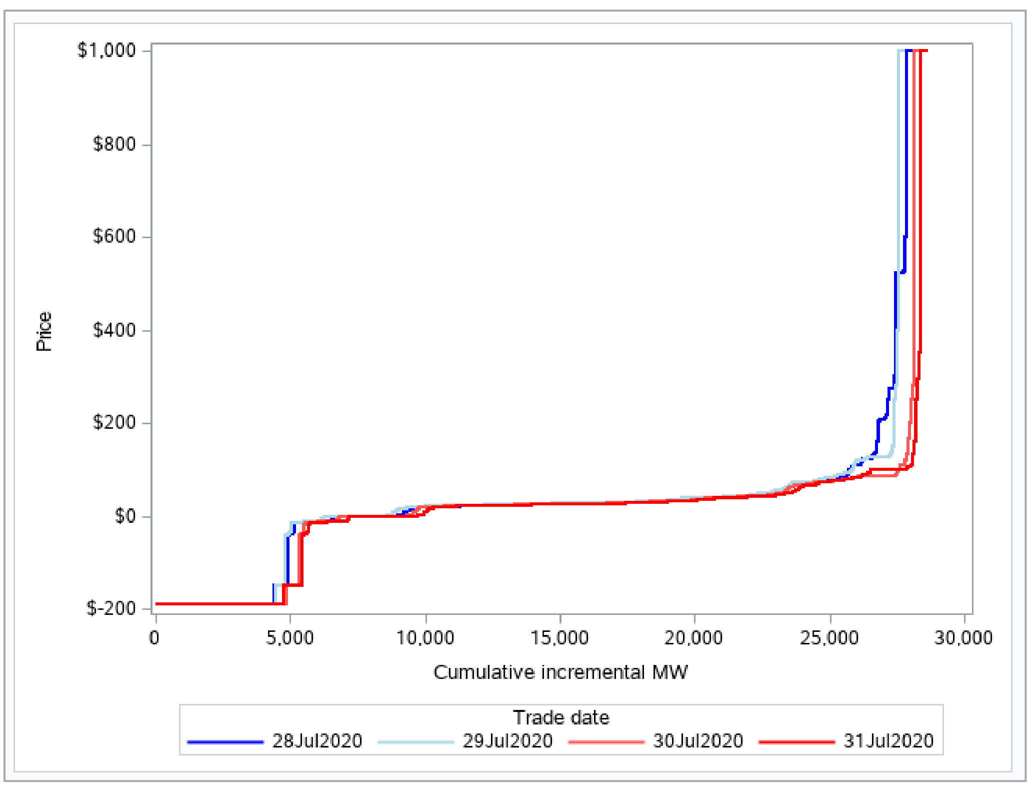


Figure 3.4 Import bids (hour 20, July 28 - 31, 2020)

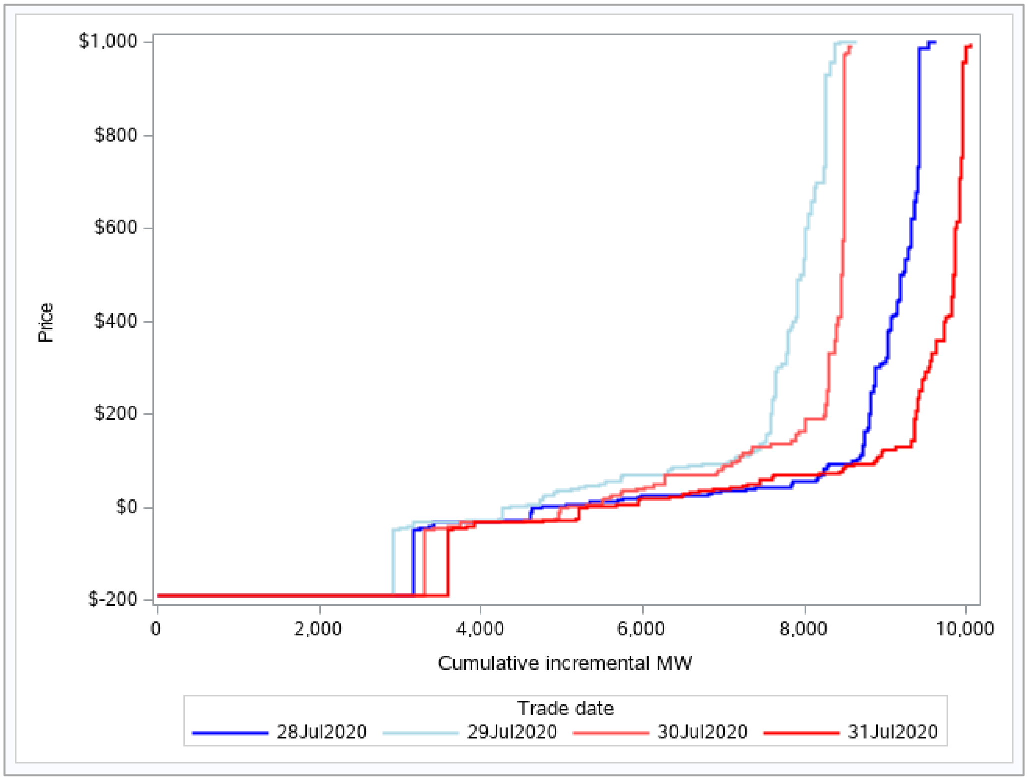


Figure 3.5 Export bids (hour 20, July 28 - 31, 2020)

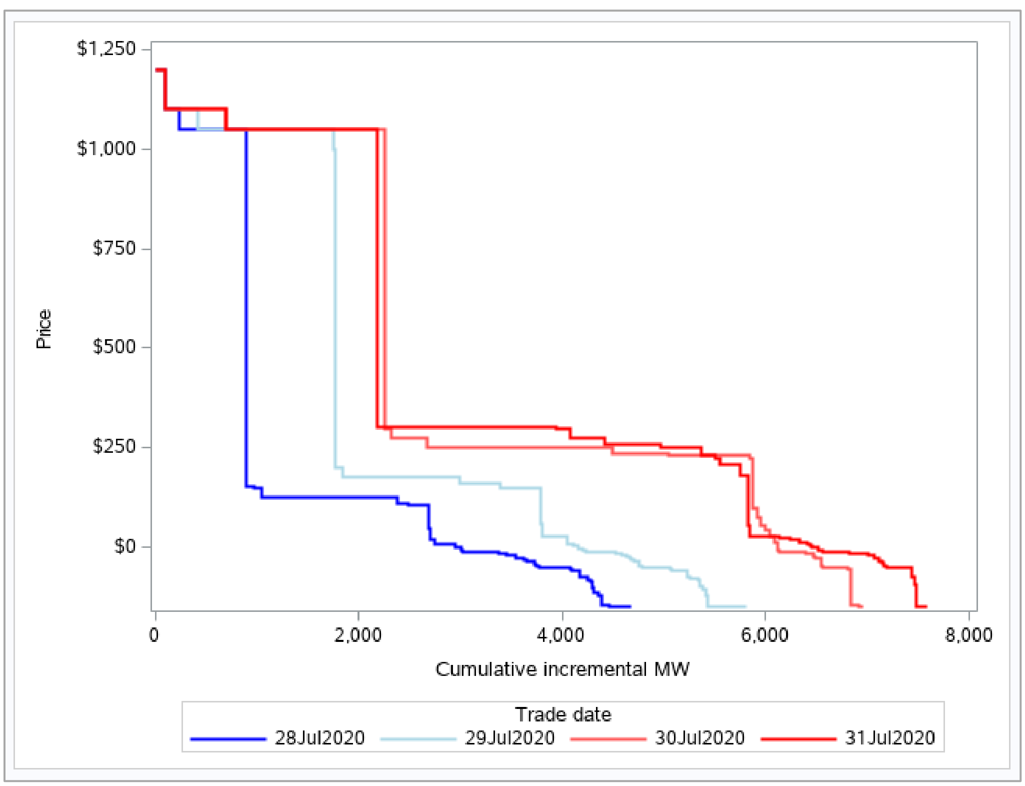


Figure 3.6 Virtual supply bids (hour 20, July 28 - 31, 2020)

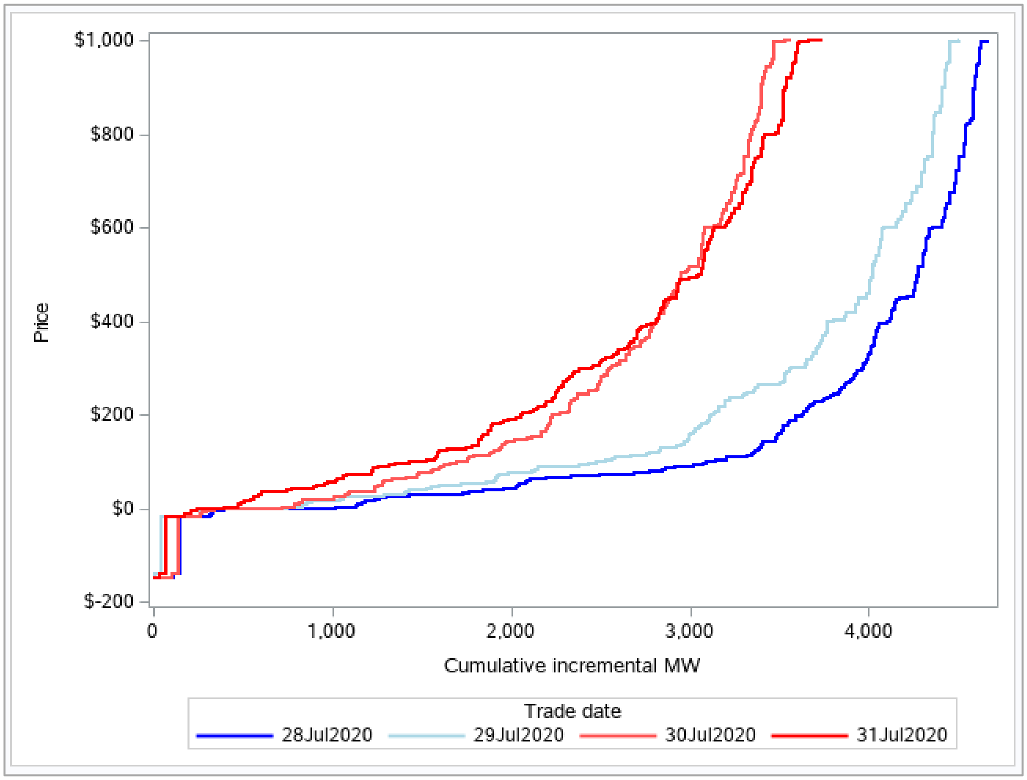
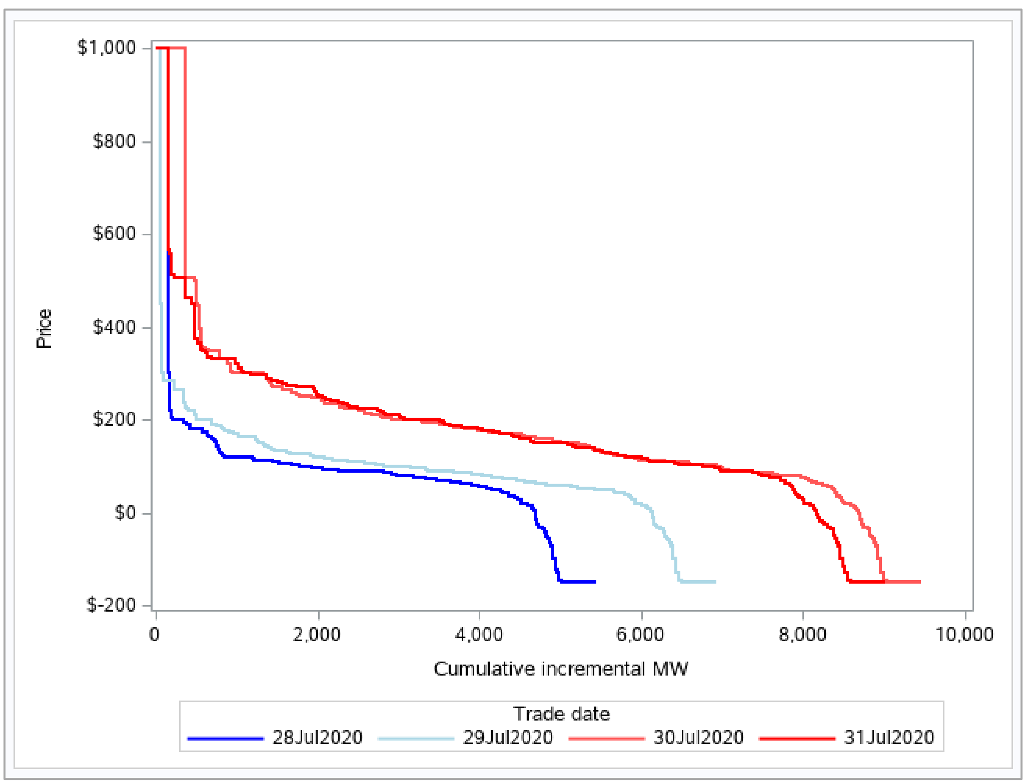


Figure 3.7 Virtual demand bids (hour 20, July 28 - 31, 2020)



California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the California Public Utilities Commission (CPUC) to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with regulatory requirements and processes adopted by the CPUC and other local regulatory authorities.

Figure 3.8 shows the hourly bids for resource adequacy resources by fuel type in the day-ahead market for July 30-31, 2020. Bids from resources shown to meet system resource adequacy requirements were sufficient to meet peak day-ahead load forecast (solid black line) on each of these days. Bids from these resources were not sufficient to meet the day-ahead forecast plus self-scheduled exports (dashed grey line) in hour ending 20 on July 31, however.

Figure 3.8 Day-ahead market hourly resource adequacy bids by type (July 30 - 31, 2020)

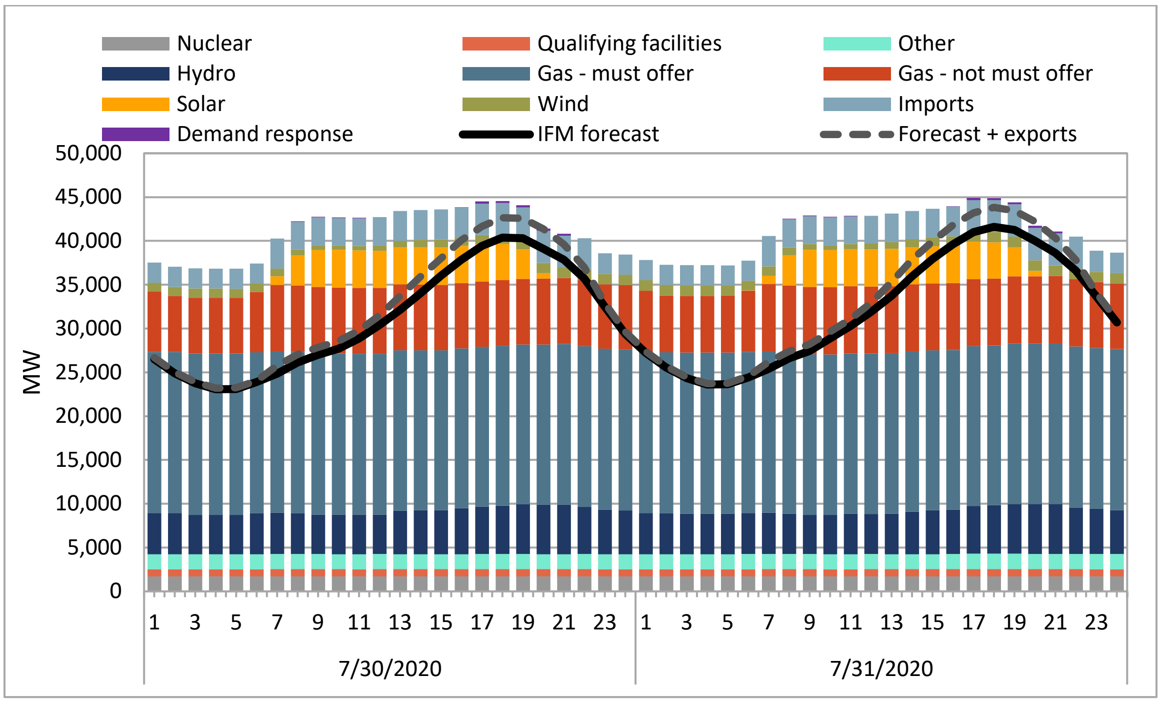


Figure 3.9 and Figure 3.10 show hourly not bid-in capacity in the day-ahead market by resource type for July 30 -31, 2020. The metric calculates this capacity in each hour by taking into account market participant submitted bids, resource capacity and any applicable outages or de-rates. As shown in these figures, not bid-in capacity is split into 5 non-overlapping categories: Use-limited, Hydro, Gas, Extremely long-start and 'other' non-gas resource types. On July 30 and 31, there is very little hourly variation in the amount of gas not bid-in capacity. For hours ending 19 and 20 on July 30, an average 980 MW of available gas capacity did not bid into the day-ahead market. About 75 percent of this capacity does not have a must-offer obligation and the ISO does not insert bids into the market. The majority of this capacity is classified as must-take and a portion of it is designated as resource adequacy capacity. About 21 percent of gas not bid-in capacity does not have a resource-adequacy designation. The remaining 4 percent is residual capacity remaining from resources after fulfilling their resource adequacy capacity obligations. Similarly, for hours ending 19 and 20 on July 31, about 800 MW of available gas capacity did not bid into the market. About 70 percent of this capacity does not have must-offer obligation and the

ISO does not insert bids into the market. The majority of this capacity is classified as must-take and a portion of it is designated as resource adequacy capacity. About 25 percent does not have a resource-adequacy designation and the remaining 5 percent is residual capacity remaining from resources after fulfilling their resource adequacy capacity obligations.

Figure 3.9 Day-ahead market hourly not bid-in capacity by type (July 30, 2020)

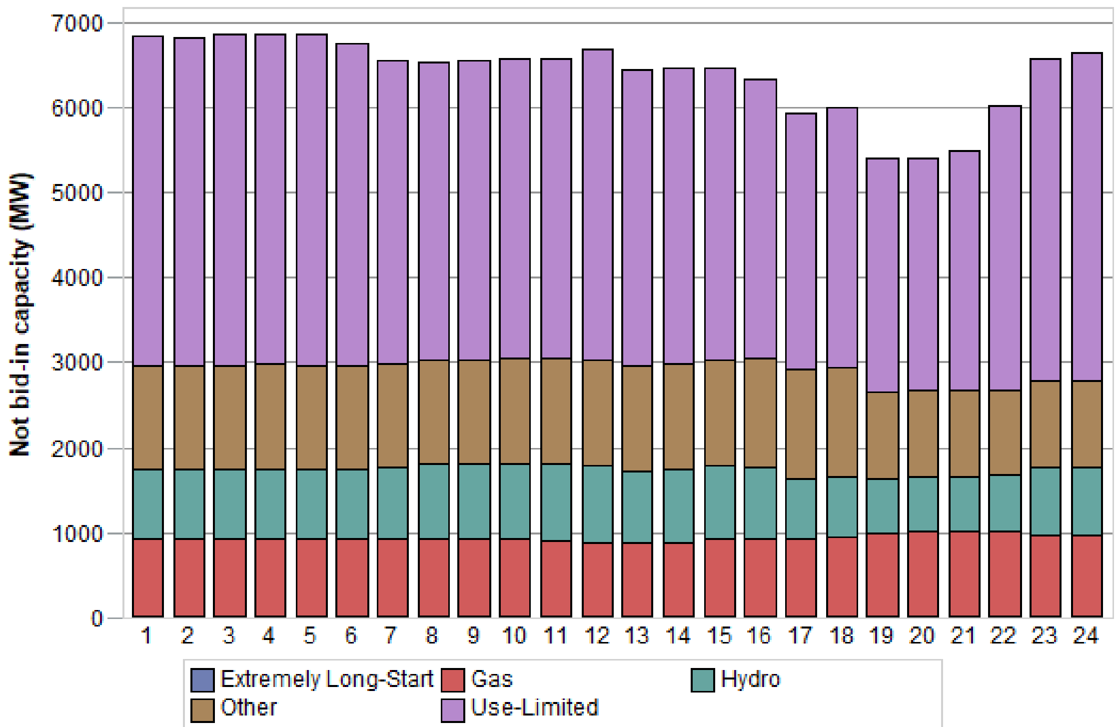
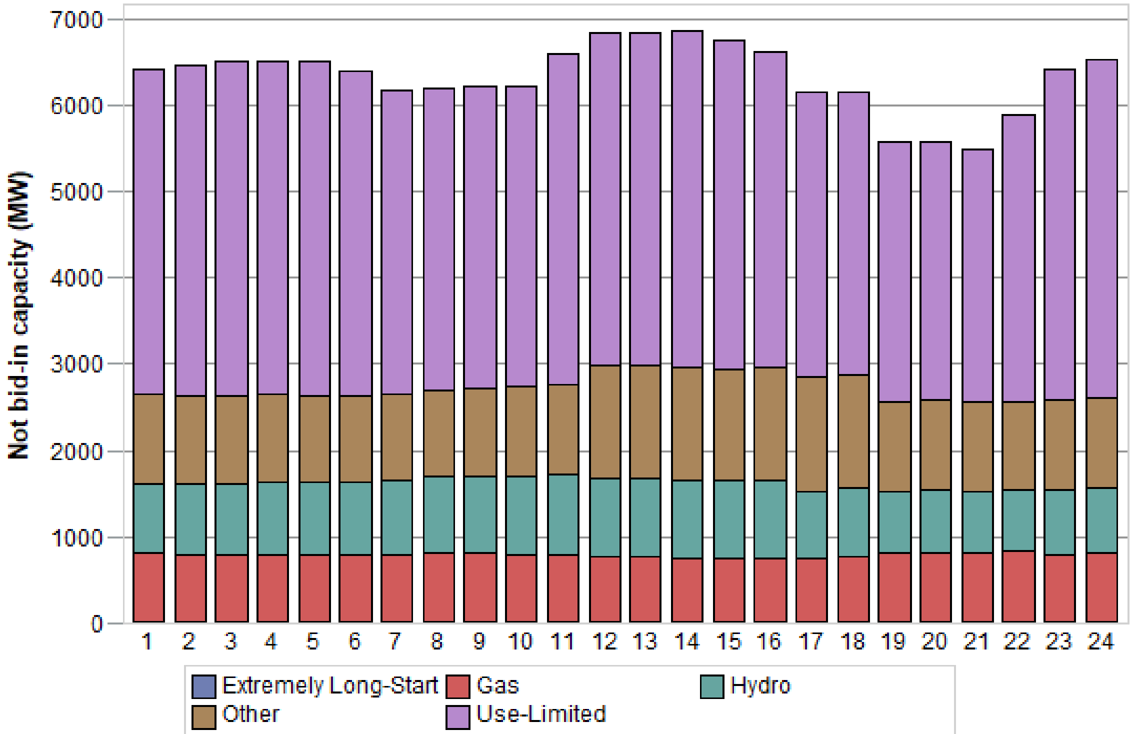


Figure 3.10 Day-ahead market hourly not bid-in capacity by type (July 31, 2020)



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 for gas generation submitted by participants to default energy bids held by net buyers. The blue line shows energy bids for these resources in the day-ahead market for hour-ending 20 on July 30 of 2020.[3] Corresponding curves for July 31 or hour-ending 19 were similar.

[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.

The supply curve shown in green shows the default energy bids associated with each bid segment. Supply from net buyers is generally 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 were at or below default energy bids for the first approximately 5,000 MW segment of the curve, but exceed reference levels for the remaining 4,200 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.

Figure 3.11 Net buyers supply input bid and reference (hour 20, July 30, 2020)

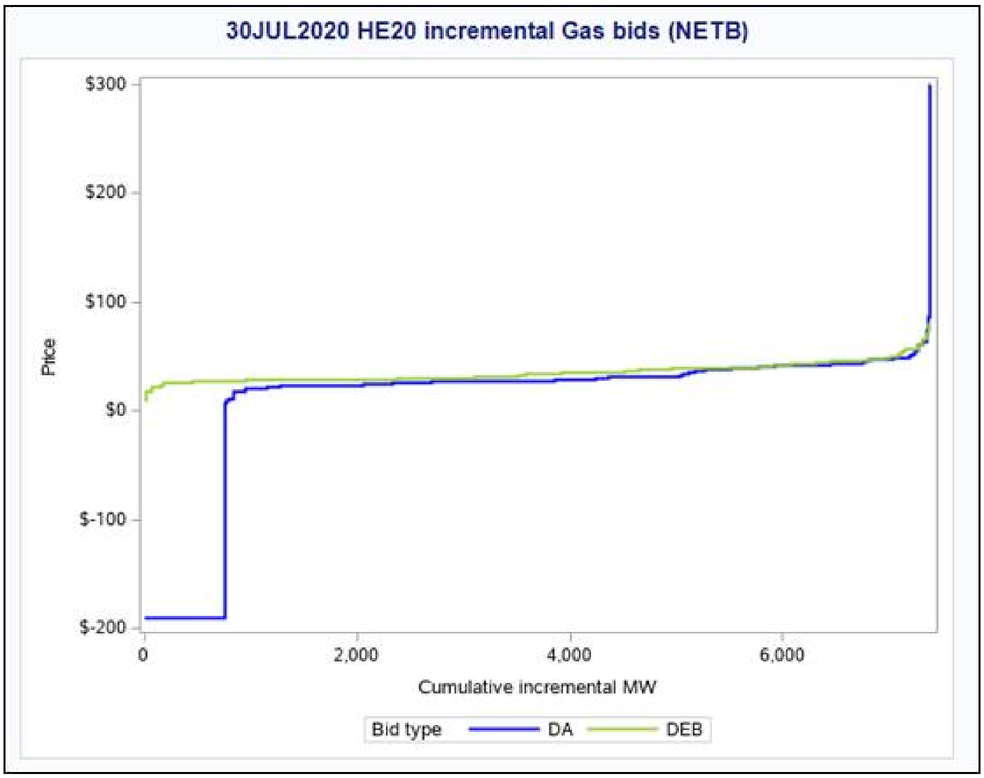
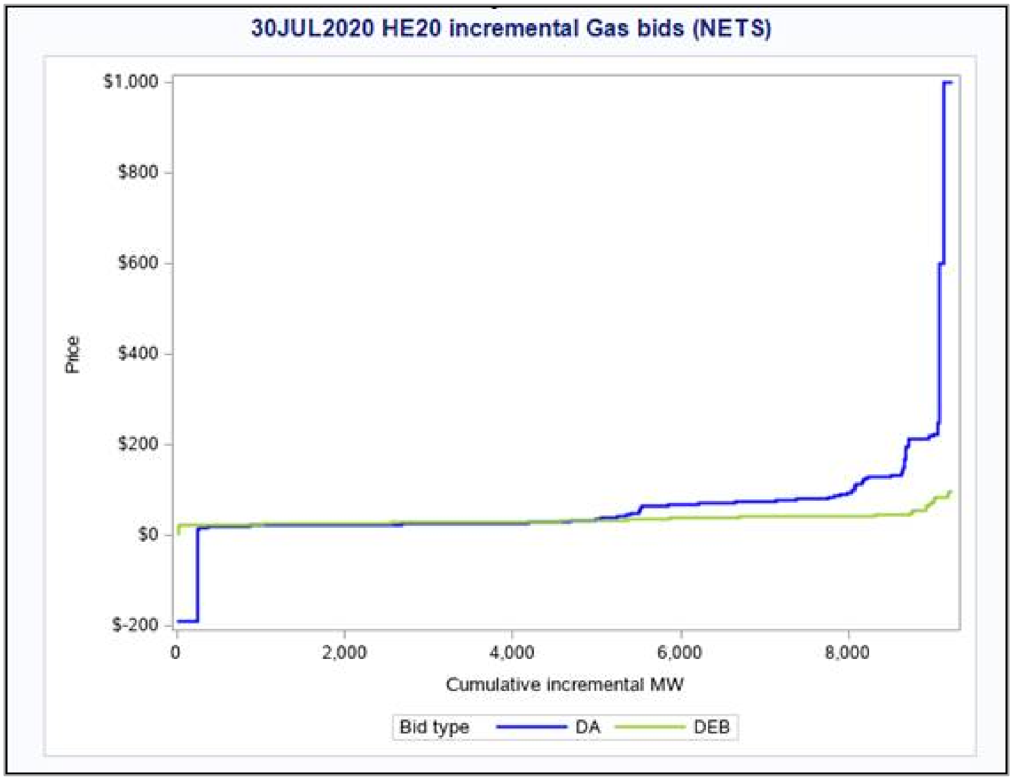


Figure 3.12 Net sellers supply input bid and reference (hour 20, July 30, 2020)



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.

Figure 3-8 shows the uncleared incremental gas-fired capacity for one of the hours analyzed in this report (July 30, hour ending 20) by resource commitment status and resource adequacy designation.[4] The black line shows the system marginal energy cost. For this hour, around 2,100 MW of gas capacity did not clear the day-ahead market, most of which was from capacity shown as resource adequacy. 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. On July 30 and 31, there was significant north-to-south congestion on Midway-Vincent in the peak-load ramping hours as a result.

Figure 3-9 instead shows uncleared import bids for July 30, hour-ending 20. Uncleared import offers on fully constrained interties were omitted from the chart. Only 440 MW of import bids on interties that were not fully constrained failed to clear. Of this, the large majority was not resource adequacy capacity.

[4] Uncleared supply in this figure *includes* energy associated with the minimum operating levels of the resources, depicted at -$250/MWh.

Figure 3.13 Uncleared incremental gas-fired capacity (Hour 20, July 30, 2020)

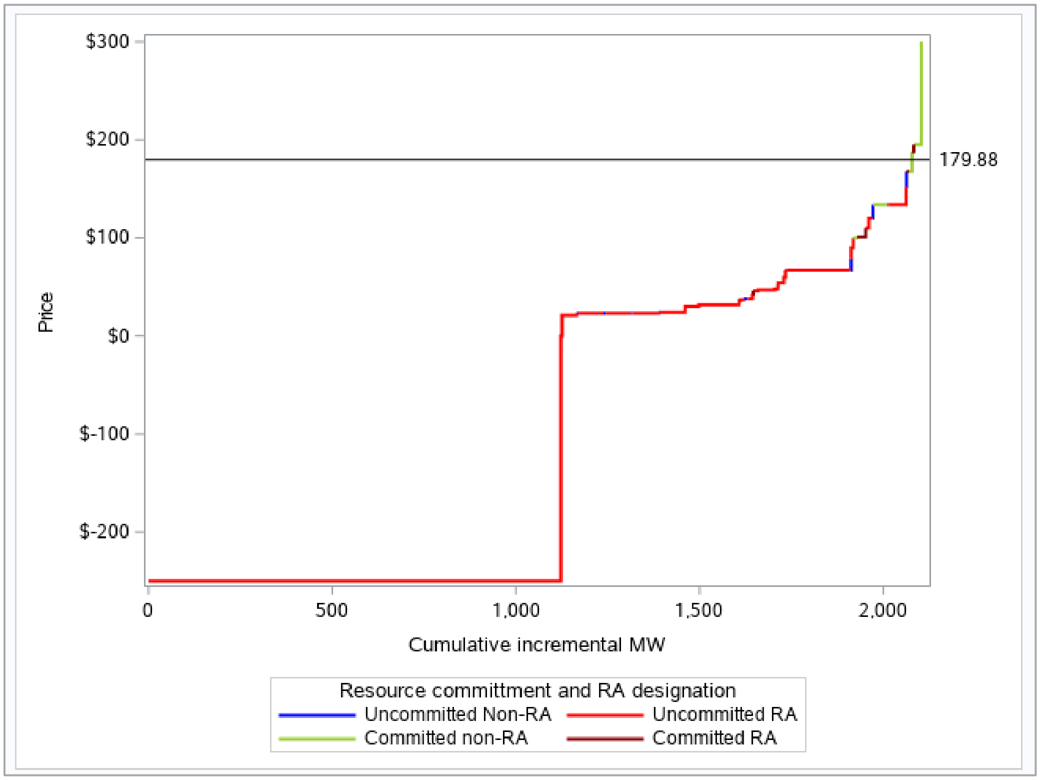


Figure 3-.3.14 Uncleared incremental import capacity (Hour 20, July 30, 2020)