Project No. 48551, Review of Summer 2018 ERCOT Market Performance

ERCOT's Review of Summer 2018 (June – August)

September 24, 2018

Key observations for summer 2018

- One of the hottest summers on record across Texas, but extreme temperatures were limited to one period (July 18 – 23) that was not as significant or as sustained as in 2011.

- Resource performance was exceptional with overall low outage numbers.

- Sufficient operating reserves were maintained. ERCOT did not initiate an Energy Emergency Alert (EEA) and did not issue any appeals for conservation.

- The market responded during peak conditions, with the majority of generation resource capacity self-committed.

Key observations for summer 2018

- There was limited remaining generation resource capacity to respond to any significant additional resource unavailability during peak conditions without the use of emergency reserves.
  - There was likely additional available response from demand-side and Distributed Energy Resources.
  - Increased visibility would allow ERCOT to better understand this potential response.

- System-wide prices were higher than in recent years, but Peaker Net Margin did not approach 2011 values.

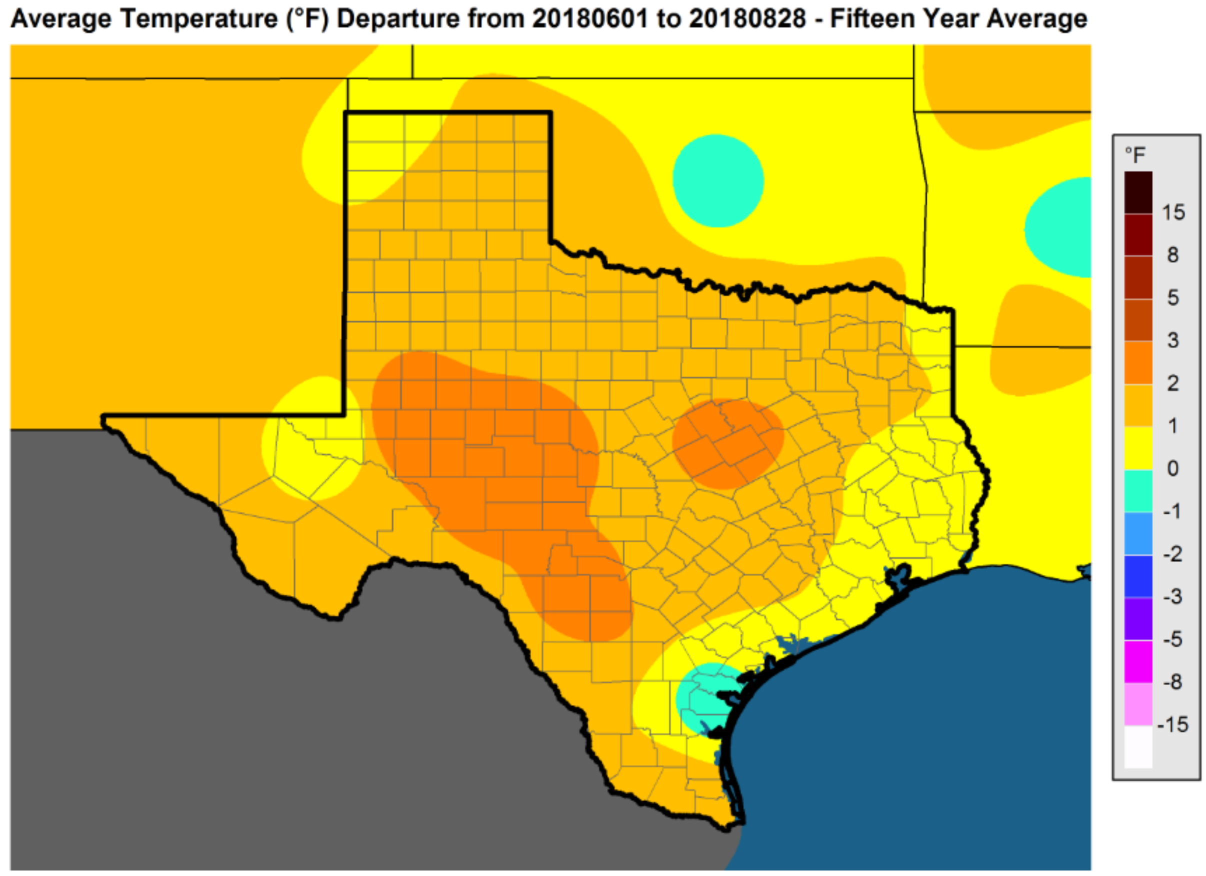
- High electricity prices in the forward markets led to an increase in collateral requirements for market participants.

June – August of 2018 was the 5th hottest June – August on record for the state of Texas, looking as far back as 1895

- 2018 temperatures for June through August were surpassed by only 2011, 1934, 1998 and 1980.

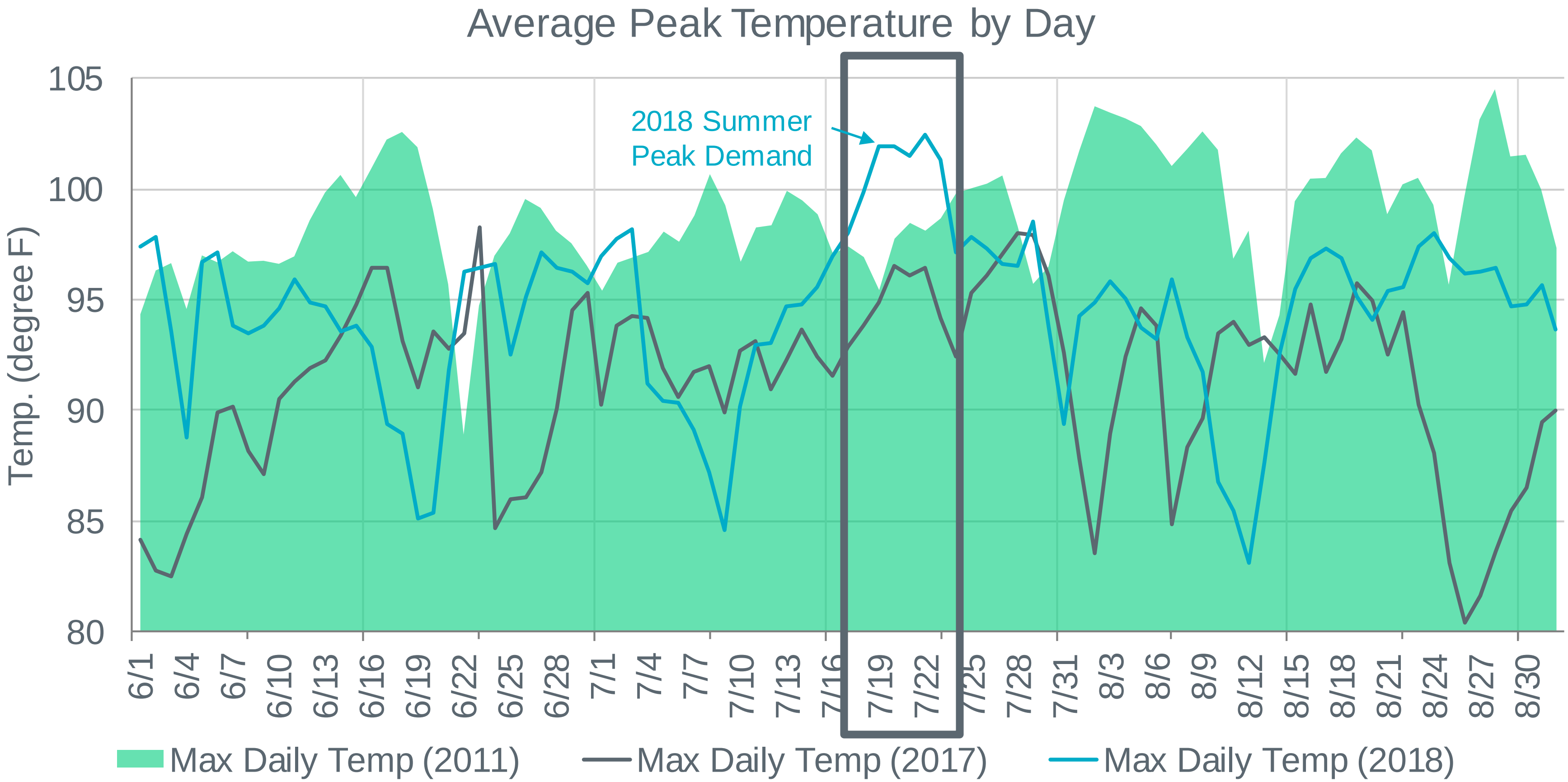
- Dallas experienced 23 days of temperatures at or above 100°F (most since 2013).

- Austin experienced 52 days of temperatures at or above 100°F (most since 2011).



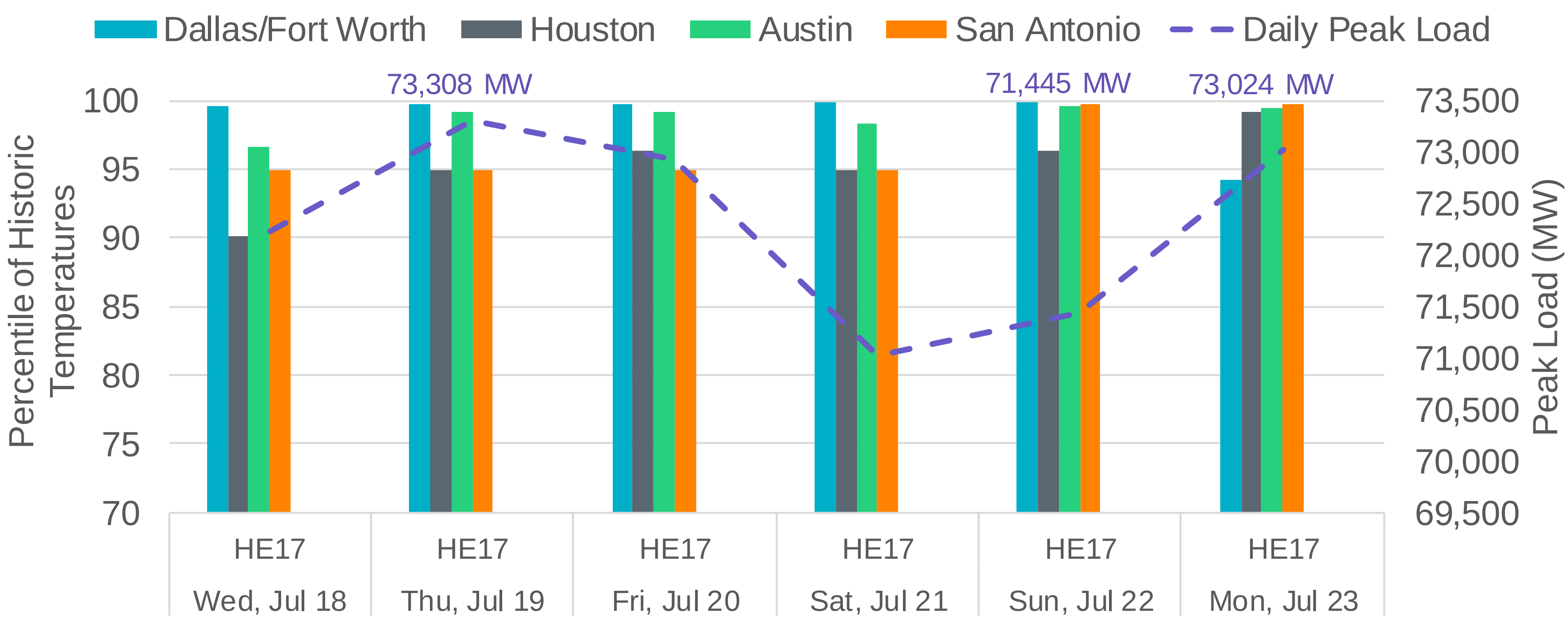
Most sustained period of higher temperatures in 2018 occurred from July 18 – 23

- 2018 temperatures were not as sustained through June, July and August as they were in 2011.



Peak hour temperatures at major load centers from July 18 – 23 were at or above 90th percentile levels

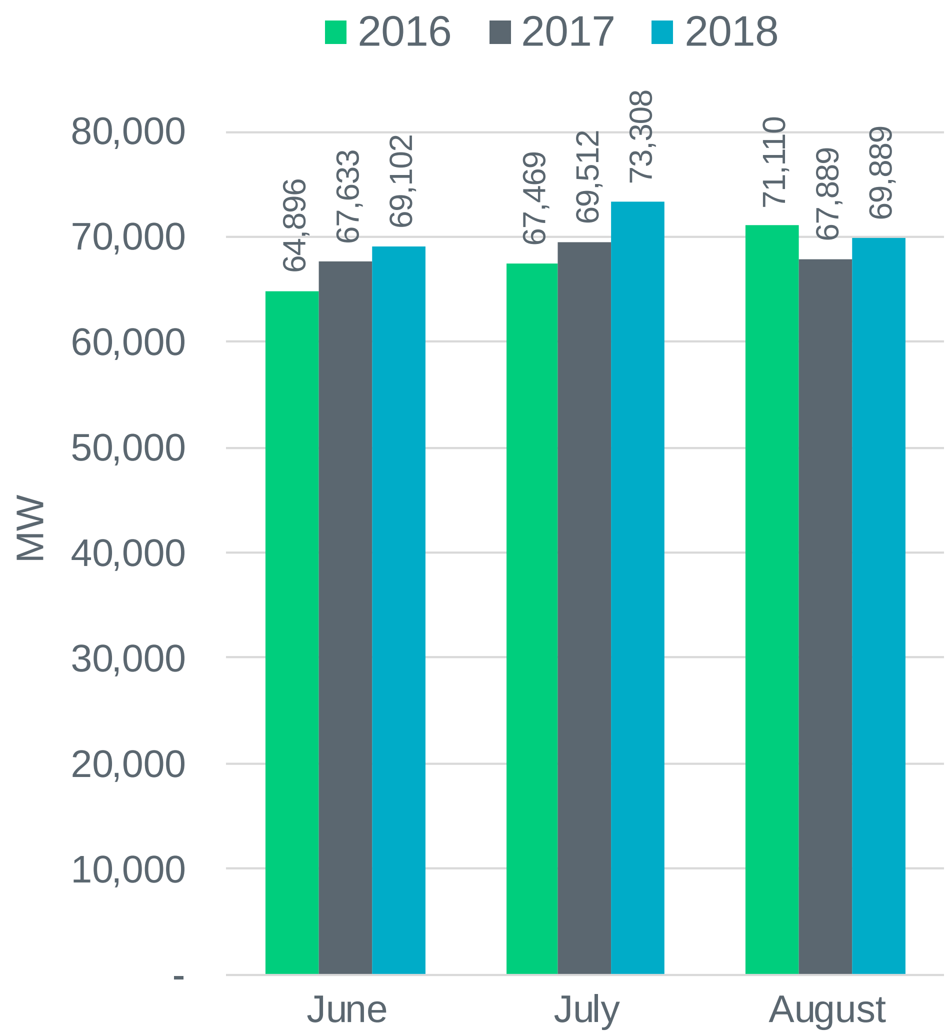
- Temperatures were at the highest percentile values on July 22. This was a Sunday, which resulted in less system-wide demand.
- July 23 saw higher percentile values except for Dallas/Fort Worth. The difference in Dallas/Fort Worth was sufficient to not surpass the July 19 record (100°F on July 23 as compared to 106°F on July 19).



- Historic data includes summer months from 1950 through 2017
- Peak load for these days did not necessarily occur at hour ending 17

The hotter temperatures generally led to increased system-wide demand

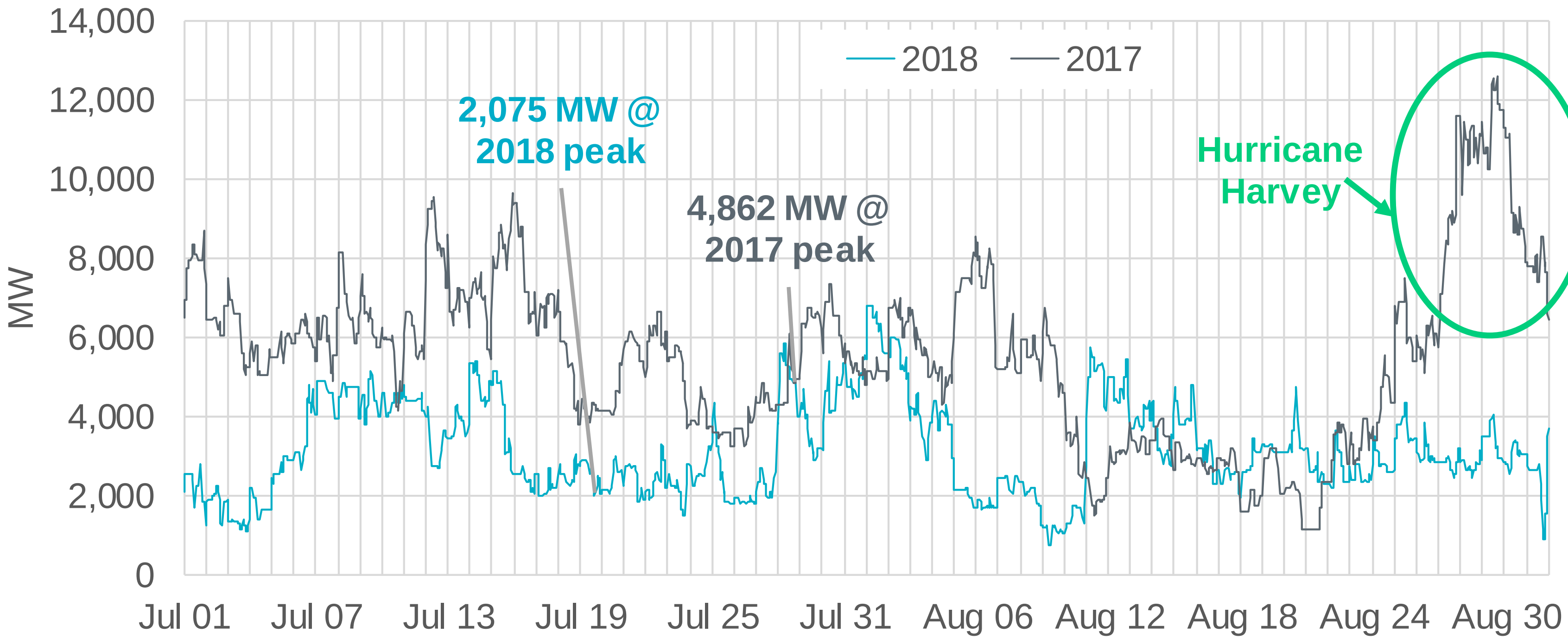
- A new all time system-wide peak demand record was set at 73,308 MW on July 19, 2018.
- A new all time system-wide peak weekend demand record was set at 71,445 MW on July 22, 2018.
- Monthly peak demand in June and July 2018 were larger than the two previous years.
- The monthly peak demand from August 2016 was not surpassed.



* Data: Hourly integrated peak demand as published in the ERCOT D&E report.

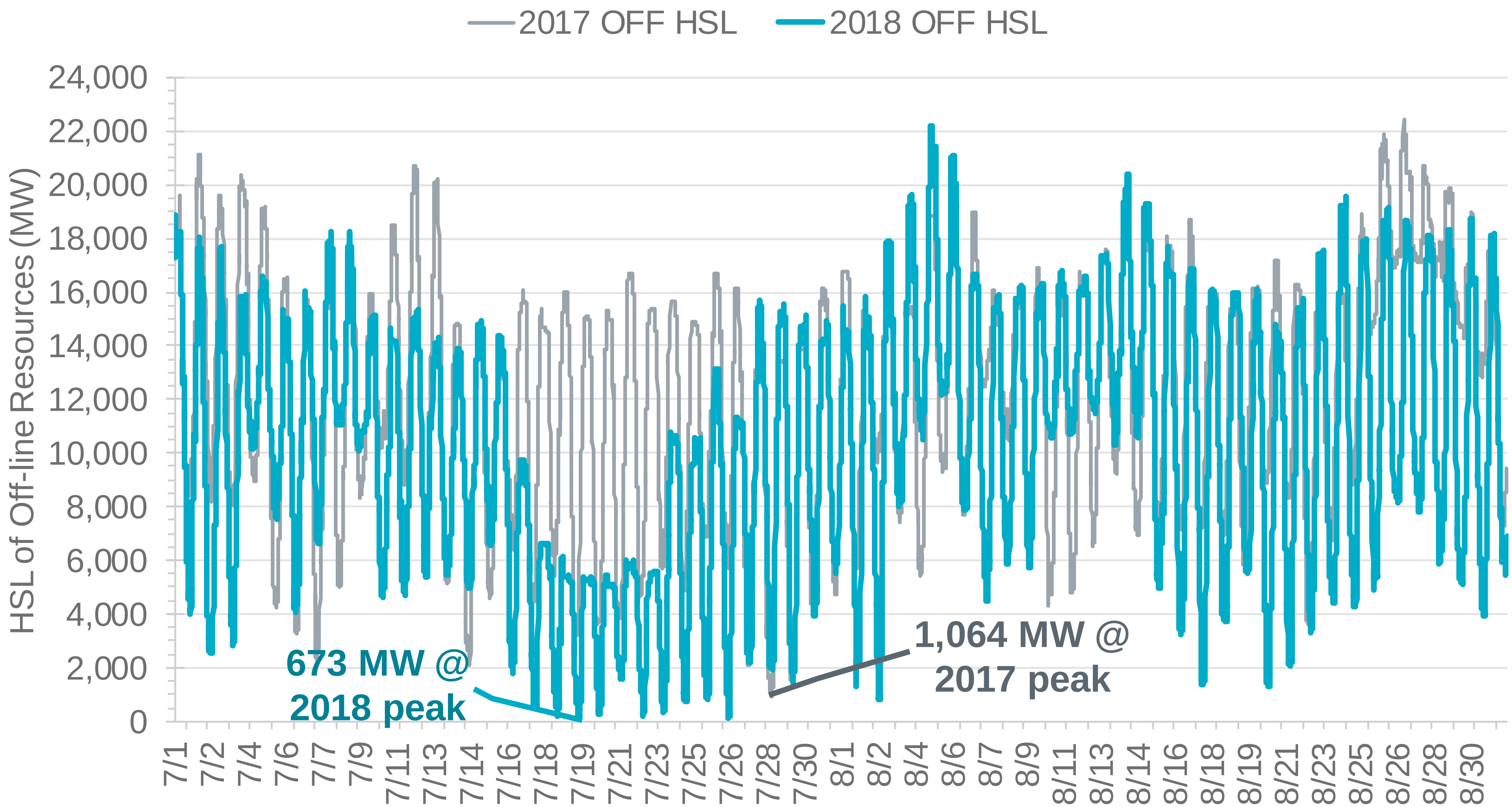
MWs of resource outages during peak demand in 2018 were especially low

- During peak demand periods, the resource outage capacity was observed to be significantly lower than in summer 2017.



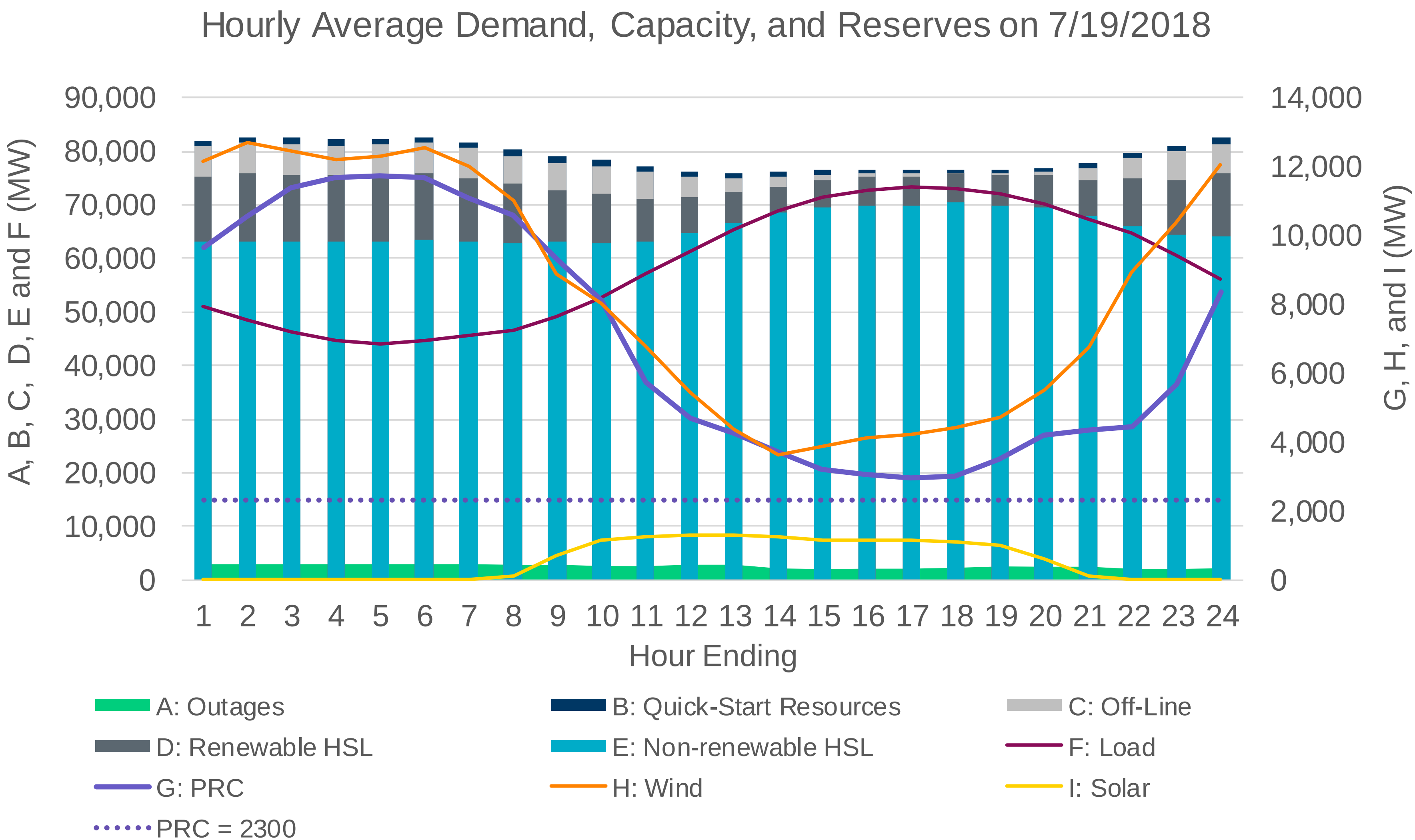
* Only uses the Outage Scheduler Data as of September 4, 2018
Excludes outages for New Equipment, Retirement, and Mothballs
Excludes outages for PUNs and IRRs.
Includes de-rates, planned, and forced outages for non-IRR, non-PUN Resources

Observed a particularly small amount of resource capacity that was off-line and available during the peak demand period in 2018



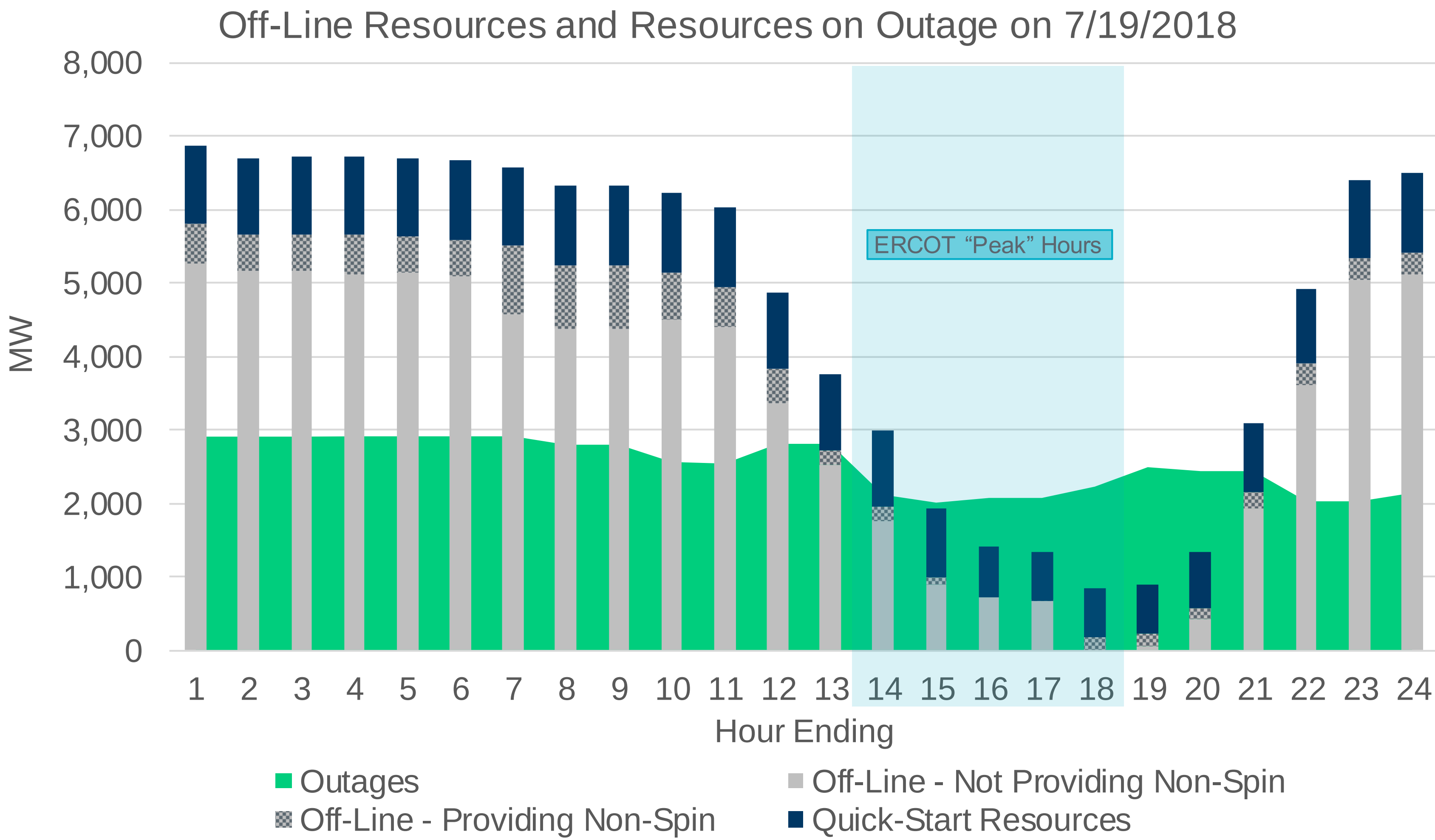
*"OFF HSL" is a summation of capacity from resources that were simply off-line and those providing non-spinning reserves as an off-line resource.

A closer look at the peak demand day of July 19



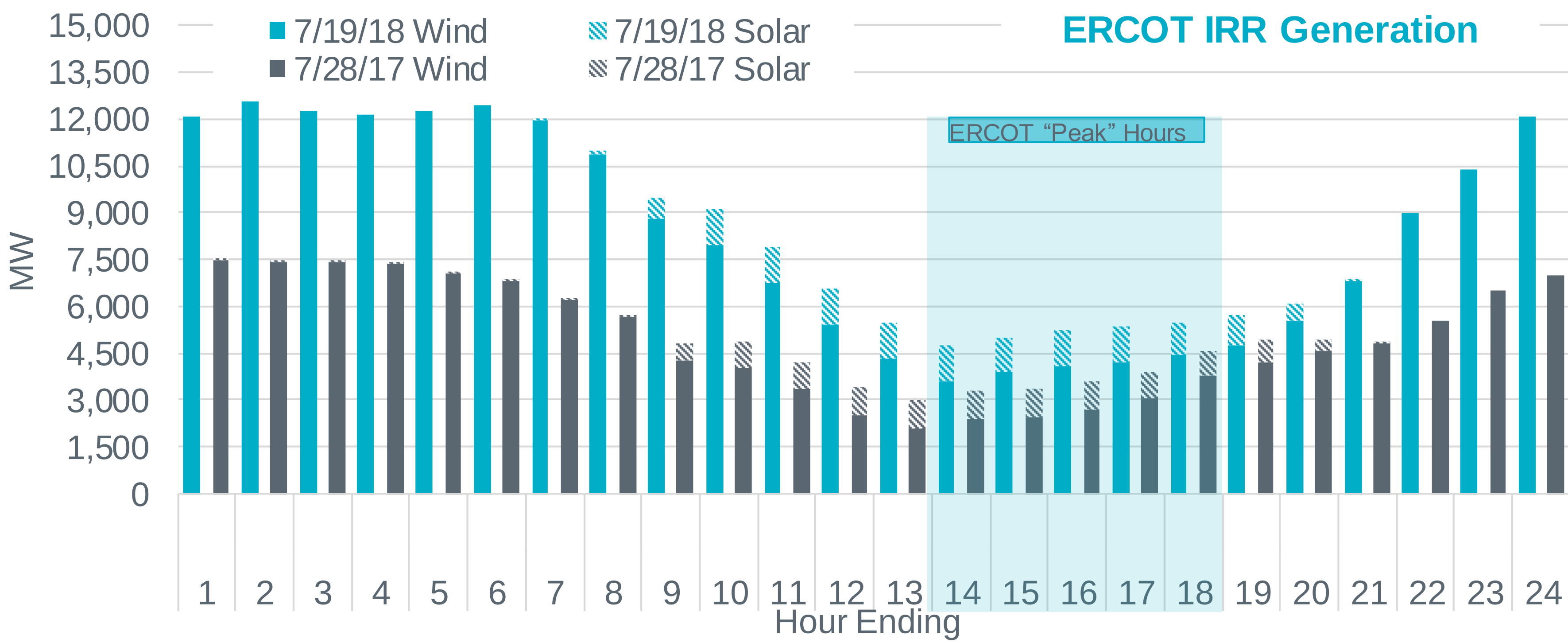
*Off-line capacity is a summation of capacity from resources that were simply off-line and those providing non-spinning reserves as an off-line resource.

During the afternoon of July 19, few resources were off-line and available or were on outage



Higher amount of Intermittent Renewable Resource (IRR) MW occurred during the 2018 peak (7/19/18), relative to 2017 peak (7/28/17)

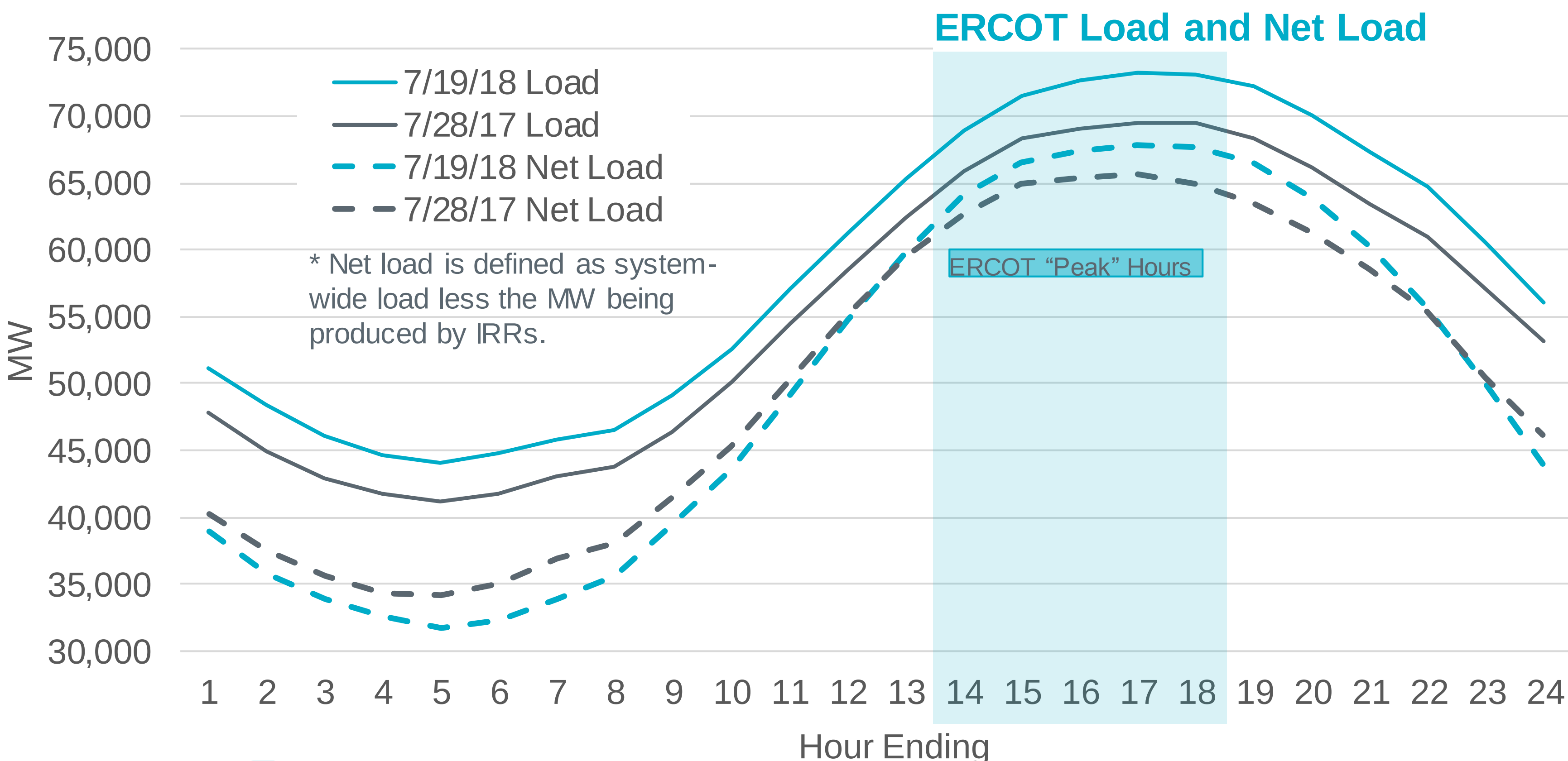
- Average wind generation during peak hours on July 19, 2018 was ~800 MW higher than on July 28, 2017. Average solar generation during peak hours on July 19, 2018 was ~400 MW higher than on July 28, 2017.
- Average wind generation during peak hours on July 19, 2018 was ~1,900 MW lower than the average for summer 2018 during those same hours of the day.



In the Final 2018 Summer SARA, wind contribution was 4,193 MW vs 4,229 MW actual and solar contribution was 1,120 MW vs 1,136 MW actual.

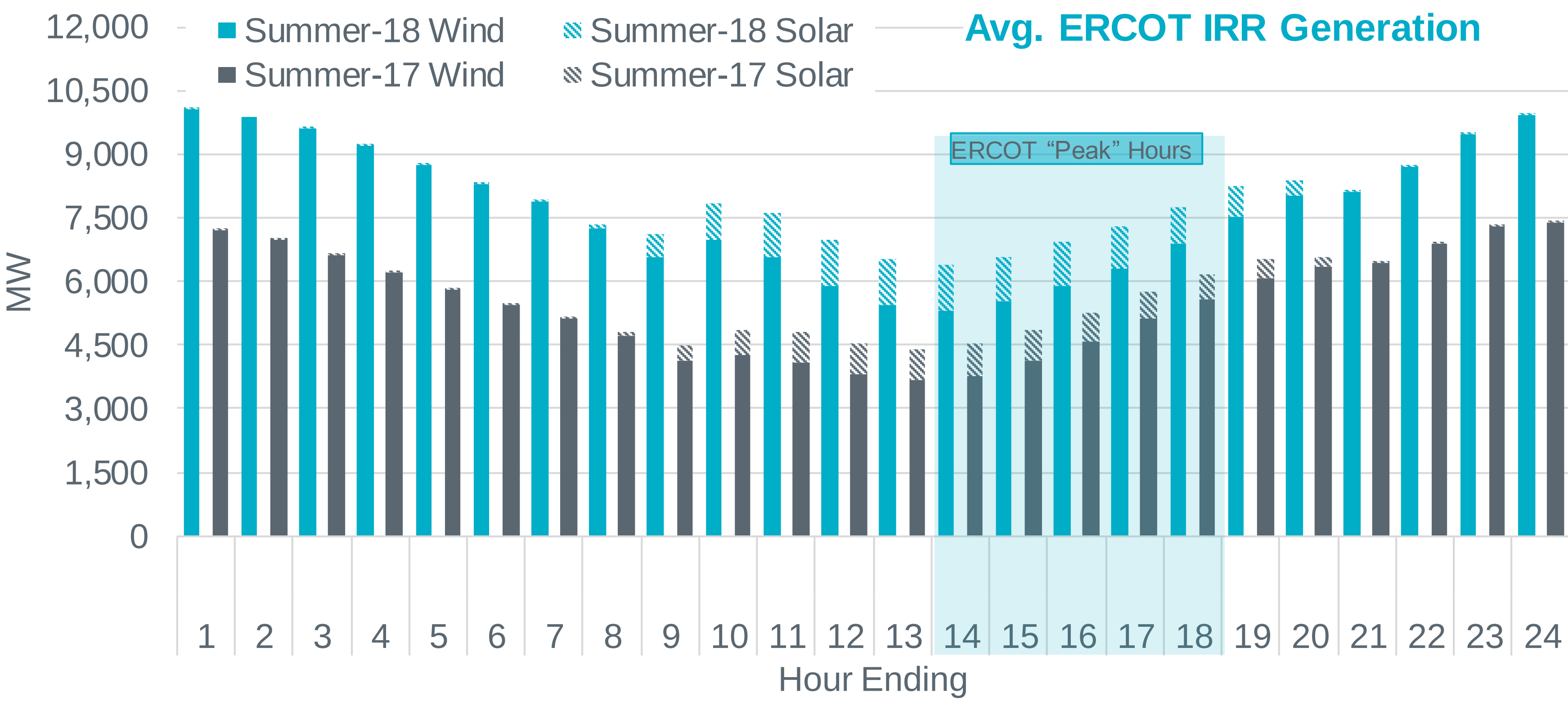
Load and net load were both higher during the peak day in 2018 (7/19/18) than in 2017 (7/28/17)

- Average load during peak hours on July 19, 2018 was ~3,600 MW (5.3%) higher than average load during peak hours on July 28, 2017. Average net load during peak hours on July 19, 2018 was ~2,300 MW (3.4%) higher than average net load during peak hours on July 28, 2017.



IRRs produced more MW on average in June, July and August 2018, relative to 2017

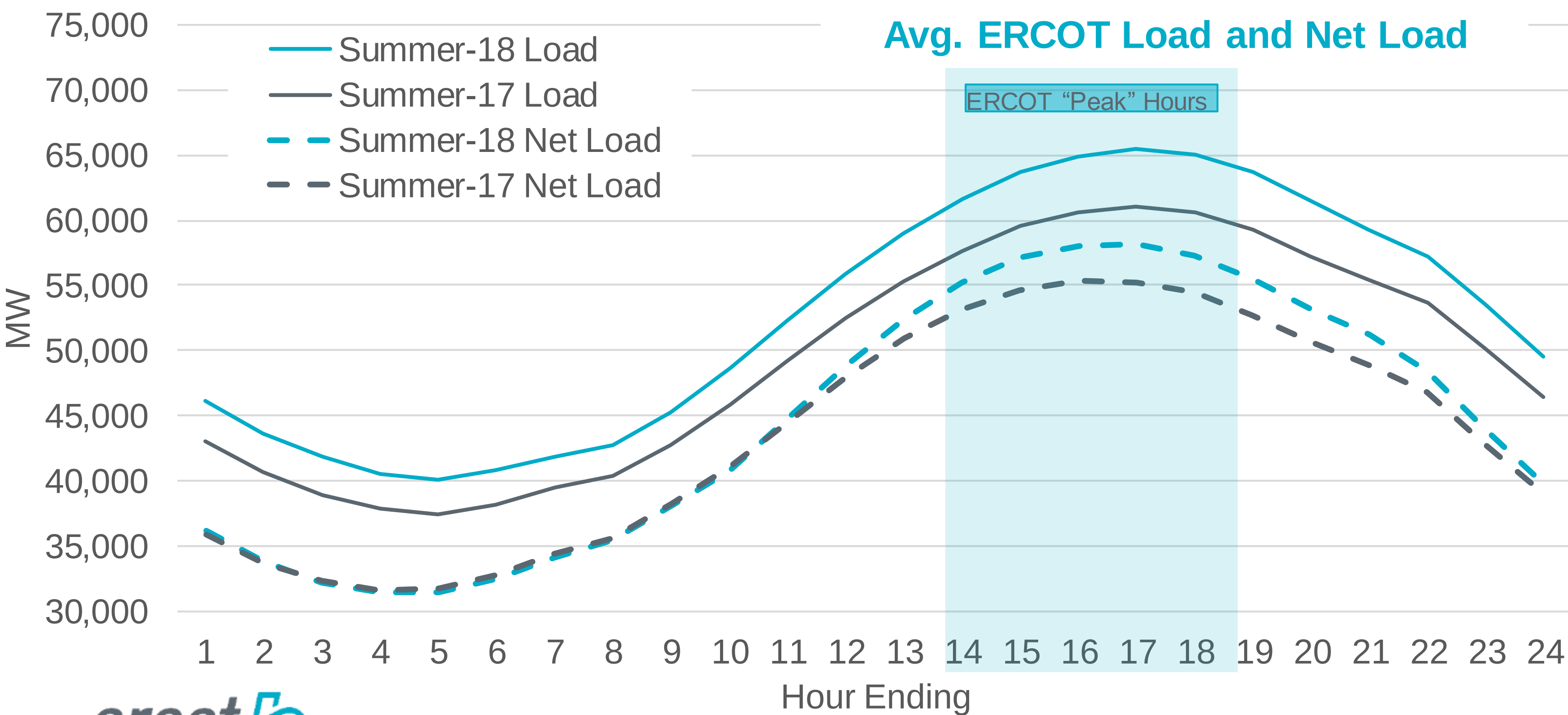
- Average wind generation during peak hours in summer 2018 was ~2,100 MW higher than summer 2017. Average solar generation during peak hours in summer 2018 was ~400 MW higher than summer 2017.



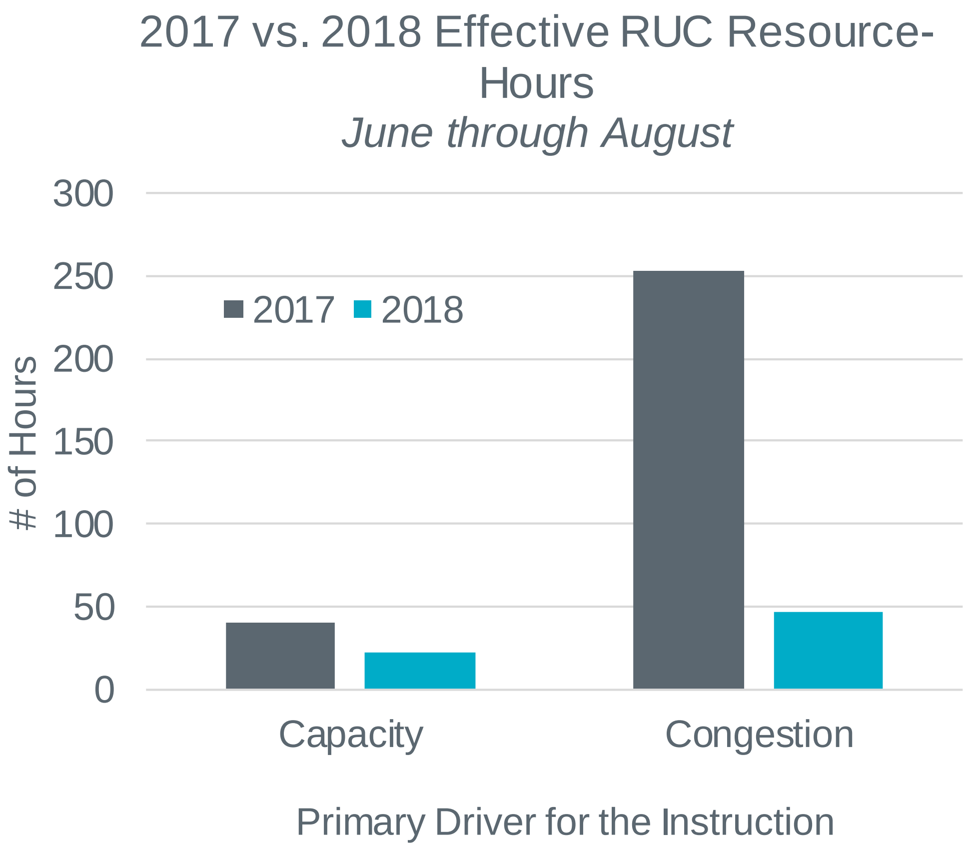
*At the end of summer 2018, ERCOT's wind installed capacity was 21,704 MW and grid-scale solar installed capacity was 1,422 MW. At the end of summer 2017, ERCOT's wind installed capacity was 20,193 MW and grid-scale solar installed capacity was 1,043 MW.

Average load and net load in June through August were both higher in 2018 than in 2017

- Average load during peak hours in summer 2018 was ~4,300 MW (7.3%) higher than average load during peak hours in summer 2017. Average net load during peak hours in summer 2018 was ~2,700 MW (4.9%) higher than average net load during peak hours summer 2017.
  - 2017 values impacted by Hurricane Harvey in August

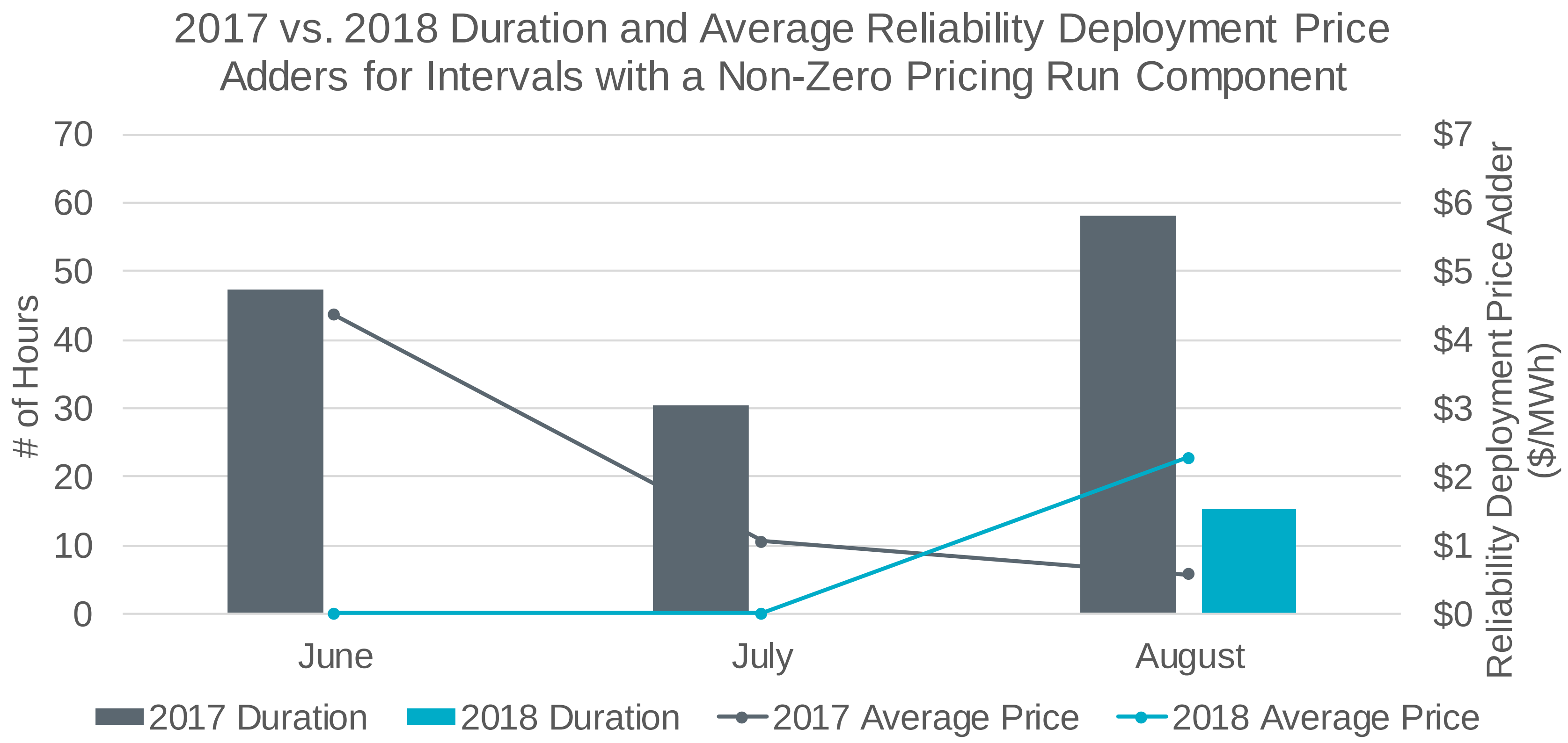


With a large majority of resources self-committed during peak periods, the number of hours of Reliability Unit Commitment (RUC) instructions were down in 2018 relative to 2017



- The decrease in RUC instructions occurred for both additional capacity as well as to help manage transmission congestion.

With the decrease in RUC instructions, there was a decrease in periods in which the reliability deployment price adder was triggered



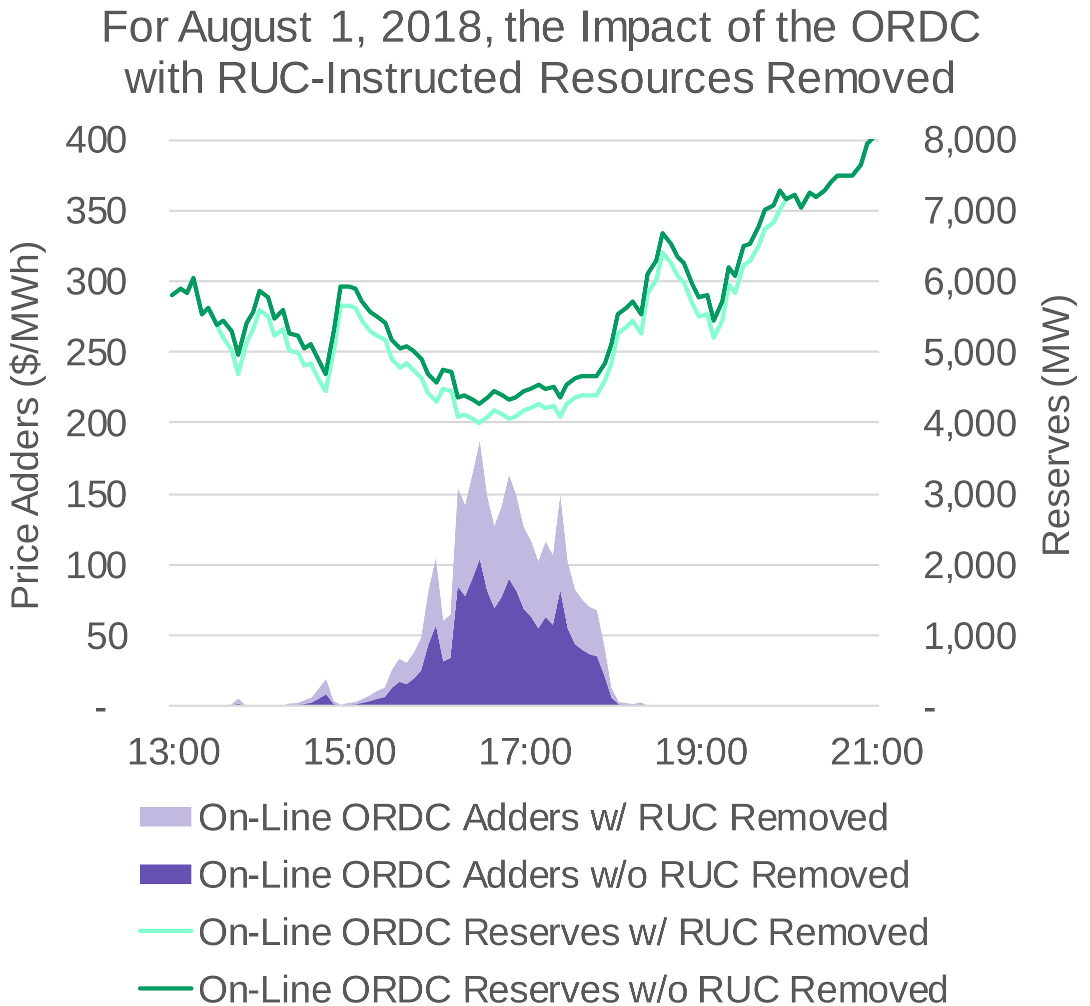
- The only triggering events for 2018 were due to RUC instructions in August.

In late May, ERCOT systems were changed to remove the impact of RUC capacity from the Operating Reserve Demand Curve (ORDC) reserves

- The change was made at the request of the PUCT.

- Events triggering the affect of this change were limited this summer, but one case was observed on August 1, 2018.

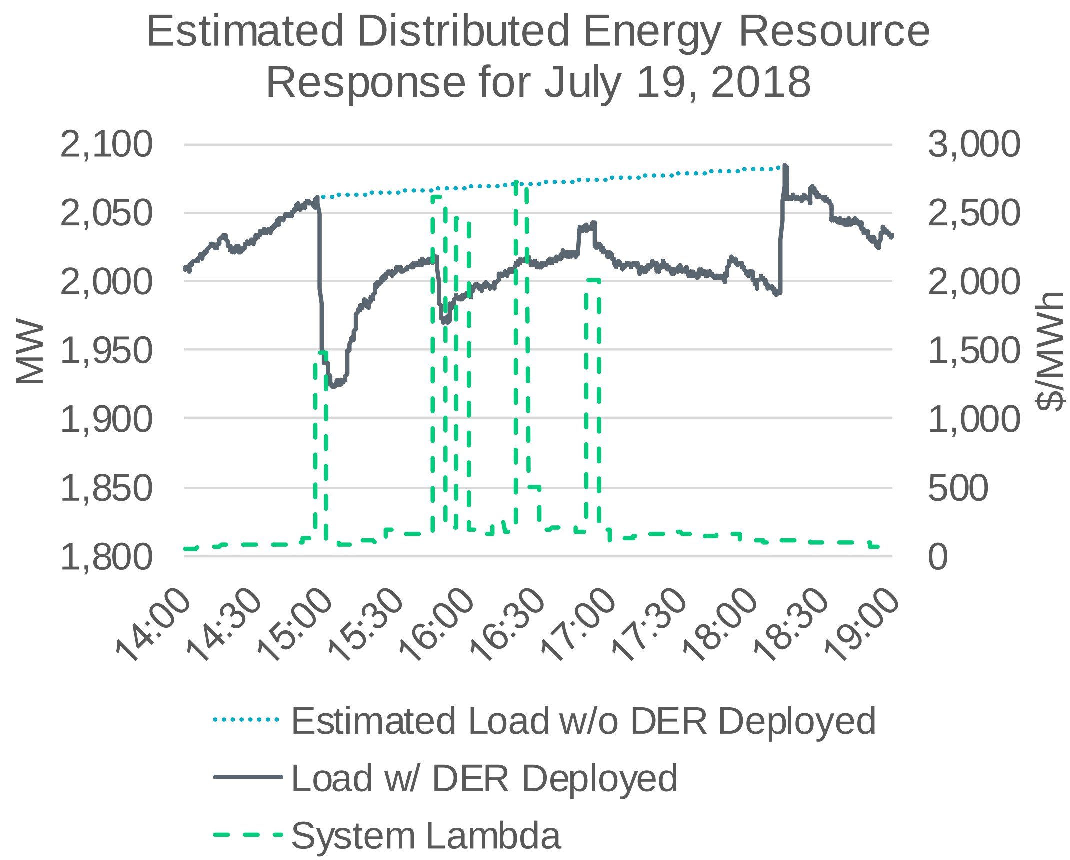
- For the recalculation of on-line ORDC reserves, 265 MW was added back to the reserves between 13:35-19:55.
  - The largest impact was an increase to the adder of ~$83/MWh at 16:30.



Based on the limited information currently available, ERCOT estimated that some Distributed Energy Resources (DERs) are responding to price

- ERCOT is currently tracking ~100 mapped, registered DERs located at 93 unique transmission-level loads.
  - ERCOT does not receive telemetry from these DERs.
  - DER response estimated based on changes in transmission-level load consumption.

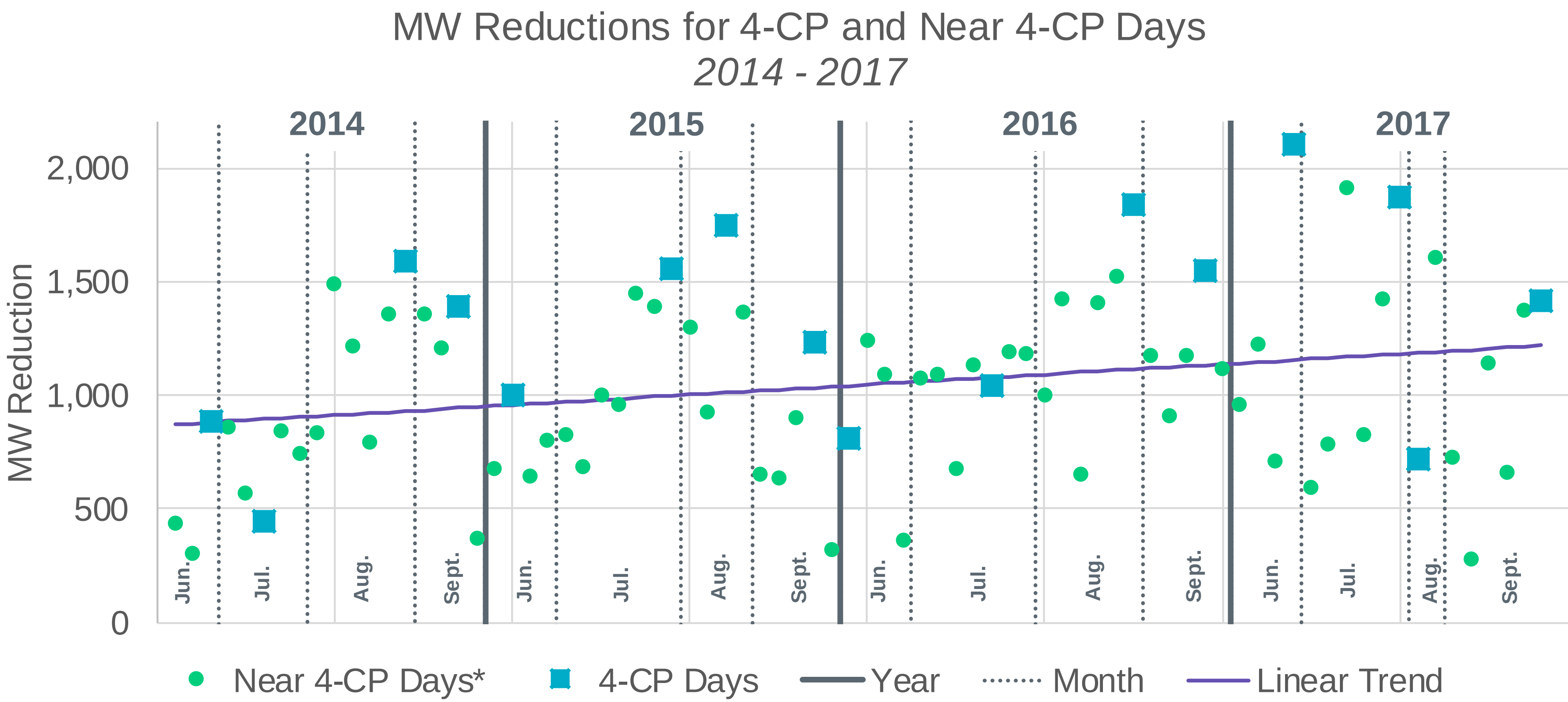
- This may include 4-Coincident Peak (4-CP) response during this Operating Day.



Aggregation of ~100 DERs located behind 93 unique transmission-level loads

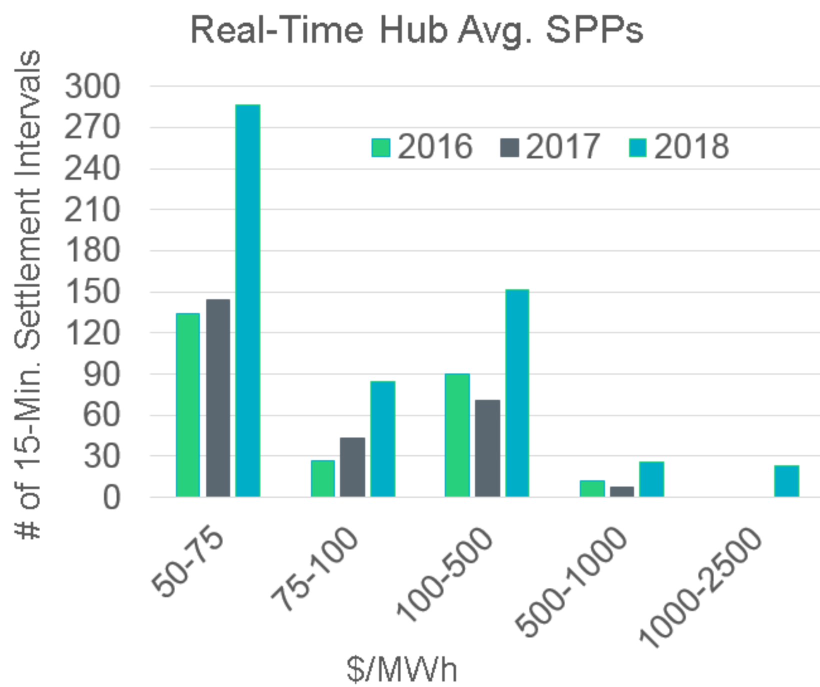
A view of 4-CP response in recent years

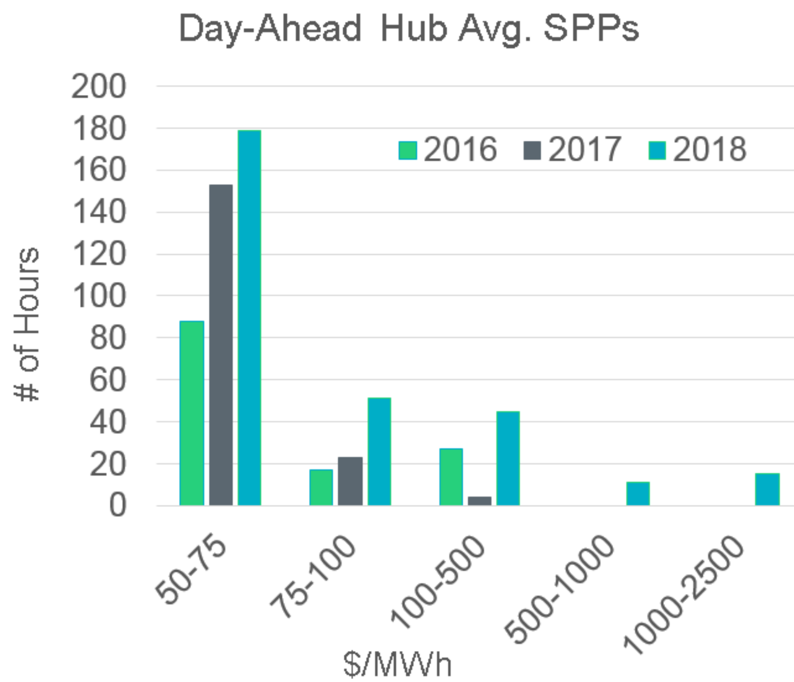
- While the information needed to evaluate 4-CP response during 2018 is not yet available, a look at the results from previous years can provide an indication of the amount of response that likely occurred in summer 2018.



* "Near 4-CP Days" for this analysis are defined as summer weekday/non-holiday days in which there was an aggregate load reduction for hour ending 17 of 5% or more for competitive ESI IDs that are served at transmission voltage and were identified as responding to 4-CP in historical analysis.

Occurrences of high system-wide Settlement Point Prices (SPPs) in the Day-Ahead Market (DAM) and Real-Time increased in June – August 2018, relative to 2016 and 2017

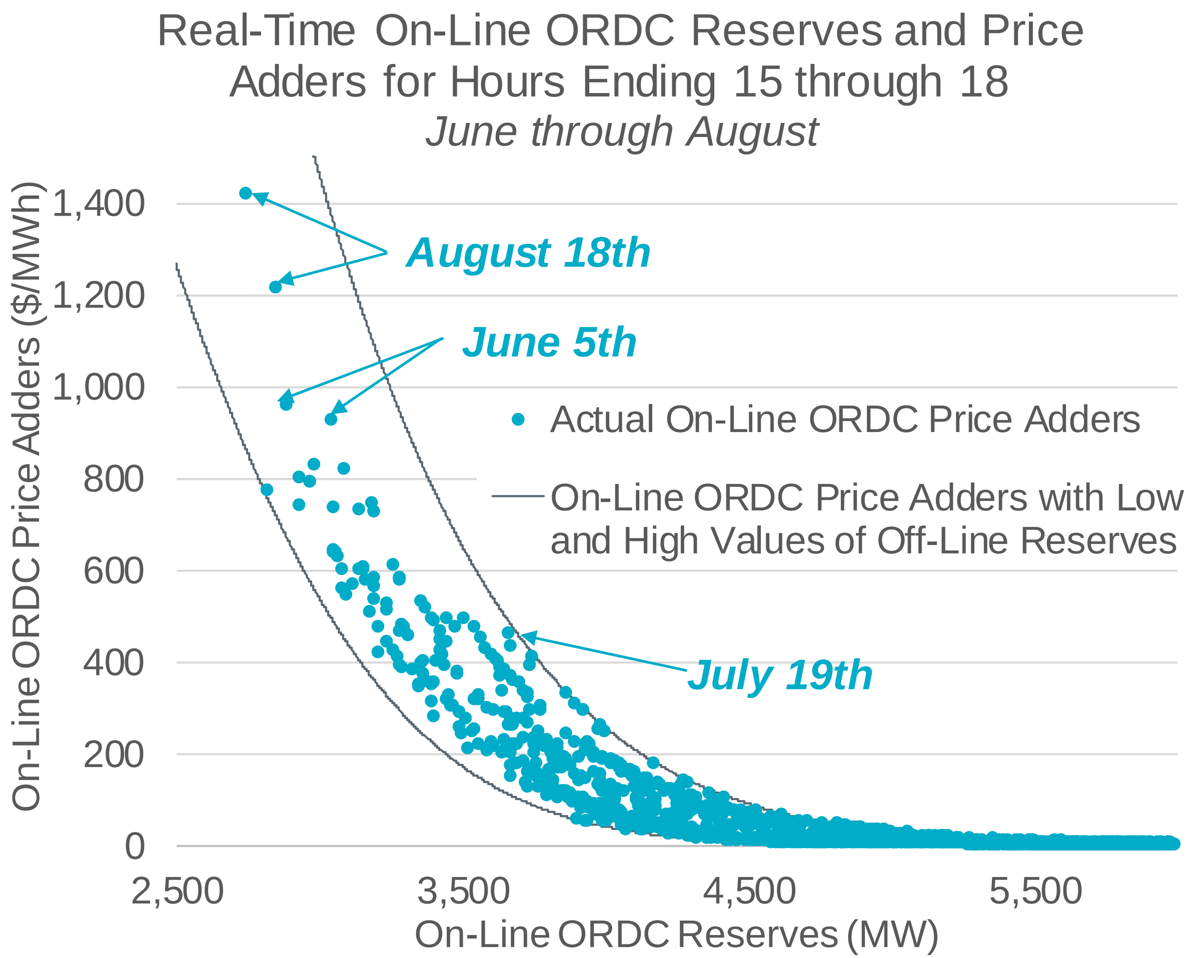




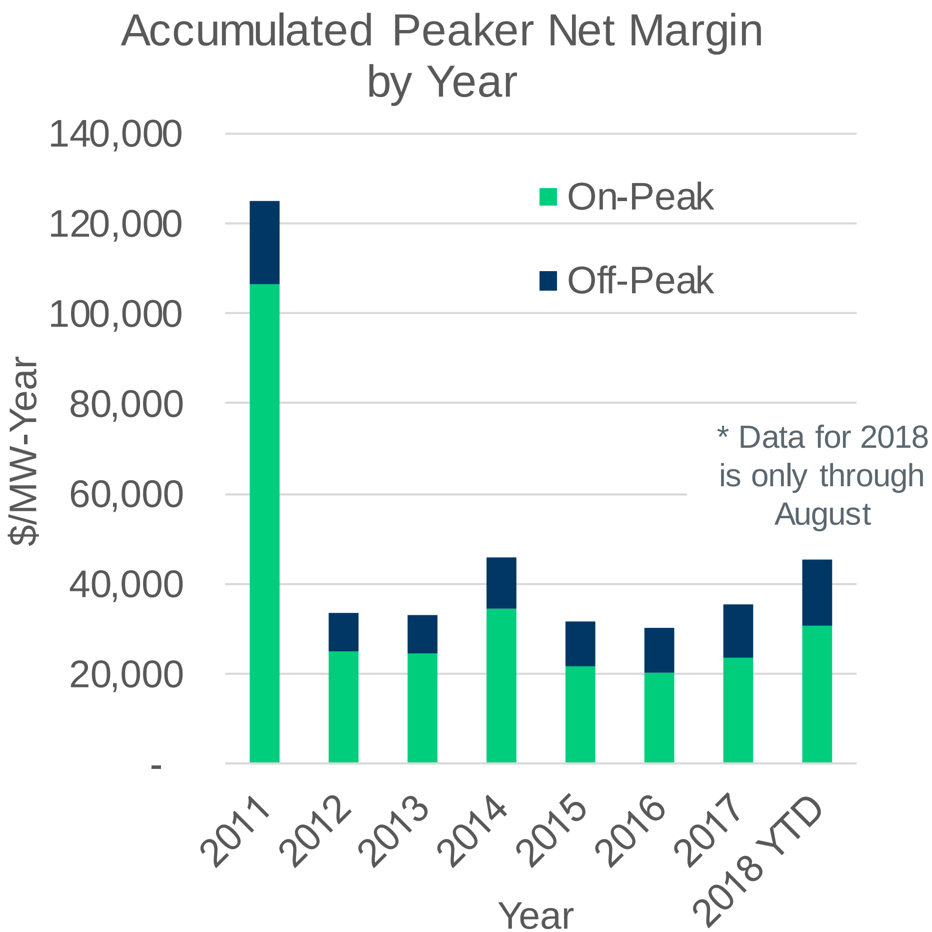
Month	2018 Avg. Hub Avg. SPP in Real-Time	2017 Avg. Hub Avg. SPP in Real-Time
June	$32.56/MWh	$28.71/MWh
July	$47.20/MWh	$30.83/MWh
August	$38.17/MWh	$28.50/MWh

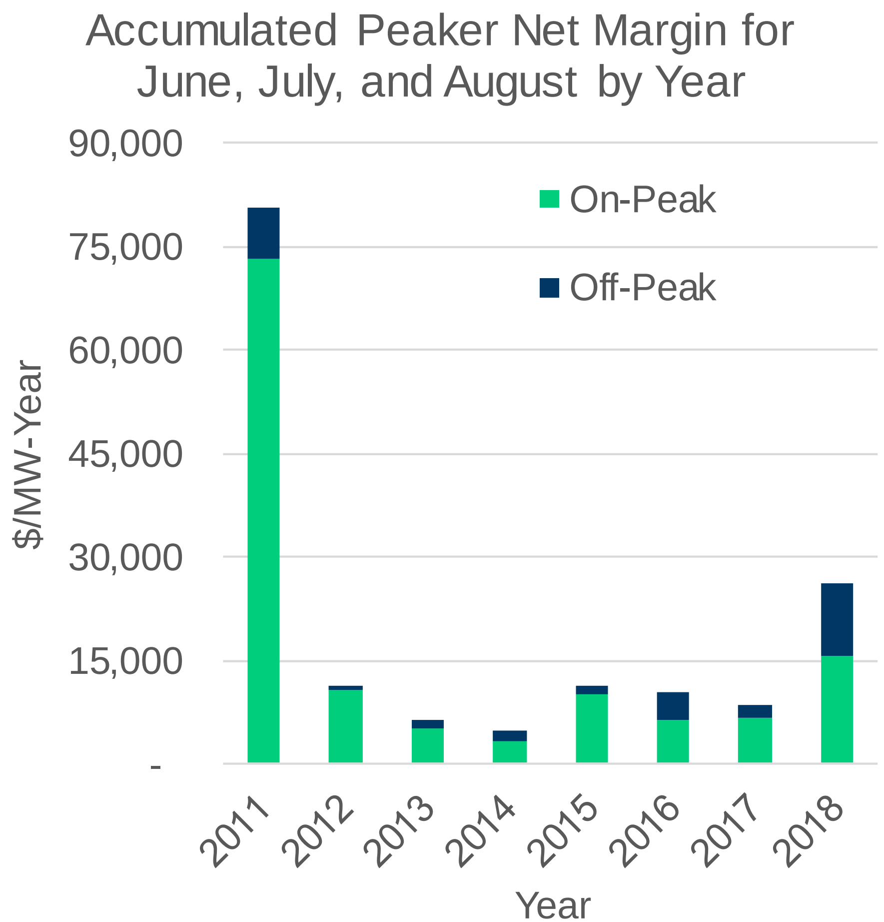
Overall reserves did not reach emergency levels, but there were periods of lower ORDC reserves and higher ORDC price adders during June – August 2018

- The day with the largest ORDC price adder was August 18.
- While there were other periods of lower off-line ORDC reserves, higher levels of on-line ORDC reserves were being observed.
  - E.g., on-line ORDC reserves remained above 3,600 MW on July 19.



Accumulated Peaker Net Margin during June – August 2018 was higher than in recent years, but did not approach the value from 2011

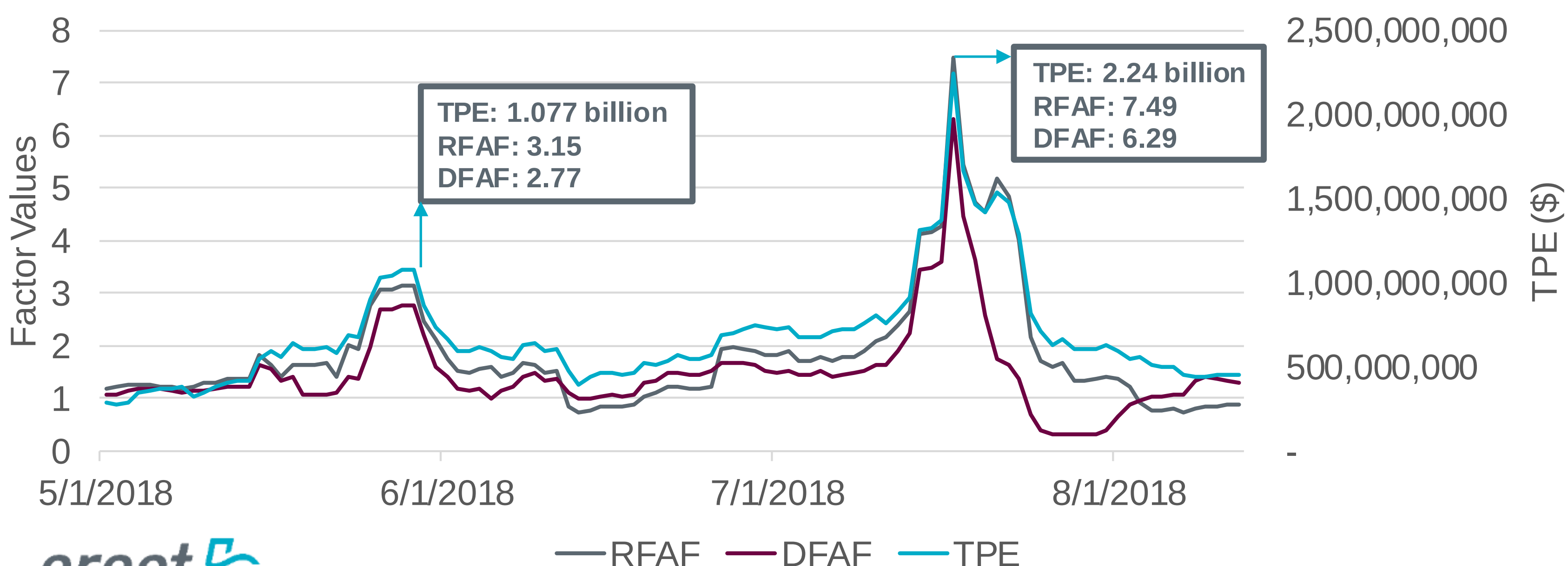




Increased forward prices led to a material increase in Total Potential Exposure (TPE) calculated for market participants, particularly in July

- A fundamental change in ERCOT's credit exposure calculations occurred in February 2018, where the Real-Time and Day-Ahead components (RFAF and DFAF) of TPE are now adjusted based on forward prices at ERCOT North Hub on a rolling 21-day horizon.

- While the increase was largely anticipated by market participants, it still prompted a larger-than-usual number of collateral calls. The majority of collateral calls were met in a timely manner.



On May 30, ERCOT initiated a Mass Transition of a competitive Retail Electric Provider (REP), transferring customers of the REP to Providers of Last Resort (POLRs)

- ERCOT and market participants identified improvements to the Mass Transition process based on lessons learned from the May event.

- In response, ERCOT:
  - Worked with PUCT staff to improve communications procedures and contacts in the event of another potential Mass Transition
  - Drafted Revision Request language to improve Mass Transition processes
  - Will conduct a drill in late 2018 or early 2019 to test systems and processes of parties involved in a Mass Transition

Completion dates for the ESI IDs in the Mass Transition

Completion Date	ESI IDs Sent to POLR
6/1/2018	7,665
6/2/2018	871
6/3/2018	58
6/4/2018	25
6/5/2018	412
6/6/2018	1
6/12/2018	1
Total:	**9,033**

* The vast majority of the ESI IDs are for residential customers

The Summer 2018 Seasonal Assessment of Resource Adequacy (SARA) values vs. actuals at peak demand

	2018 Actual Peak Demand (7/19/18)	Final 2018 Summer SARA*
Total Resources, MW	77,558	78,184
Thermal and Hydro	65,200	66,457
Private Use Networks, Net to Grid	3,019	3,298
Switchable Generation Resources	3,057	2,727
Wind Capacity Contribution	4,229	4,193
Solar Capacity Contribution	1,136	1,120
Non-Synchronous Ties	917	389
Peak Demand, MW	73,308	72,756
Reserve Capacity, MW	4,250	5,428
Total Outages, MW	**2,075***	4,349
Extreme Outage Scenario		6,915
Capacity Available for Operating Reserves, MW	2,175	1,079

No outages greater than 500 MW

Source: Final 2018 Summer SARA

* The totals for the Final 2018 Summer SARA column combine multiple rows into a single row in some cases (E.g., already in-service Thermal and Hydro Resources with planned Thermal and Hydro Resources).

** The outage information in this table was extracted on September 4, 2018.

The Capacity, Demand, and Reserves (CDR) report values vs. actuals at peak demand

- While the December ‘17 CDR noted a reserve margin of 9.3%, response from the market and delays in new industrial demand led to an 11% reserve margin going into the summer.
  - The 11% reserve margin was discussed in a news release on April 30, 2018 and was calculated using CDR-based logic and data collected for the Final 2018 Summer SARA.

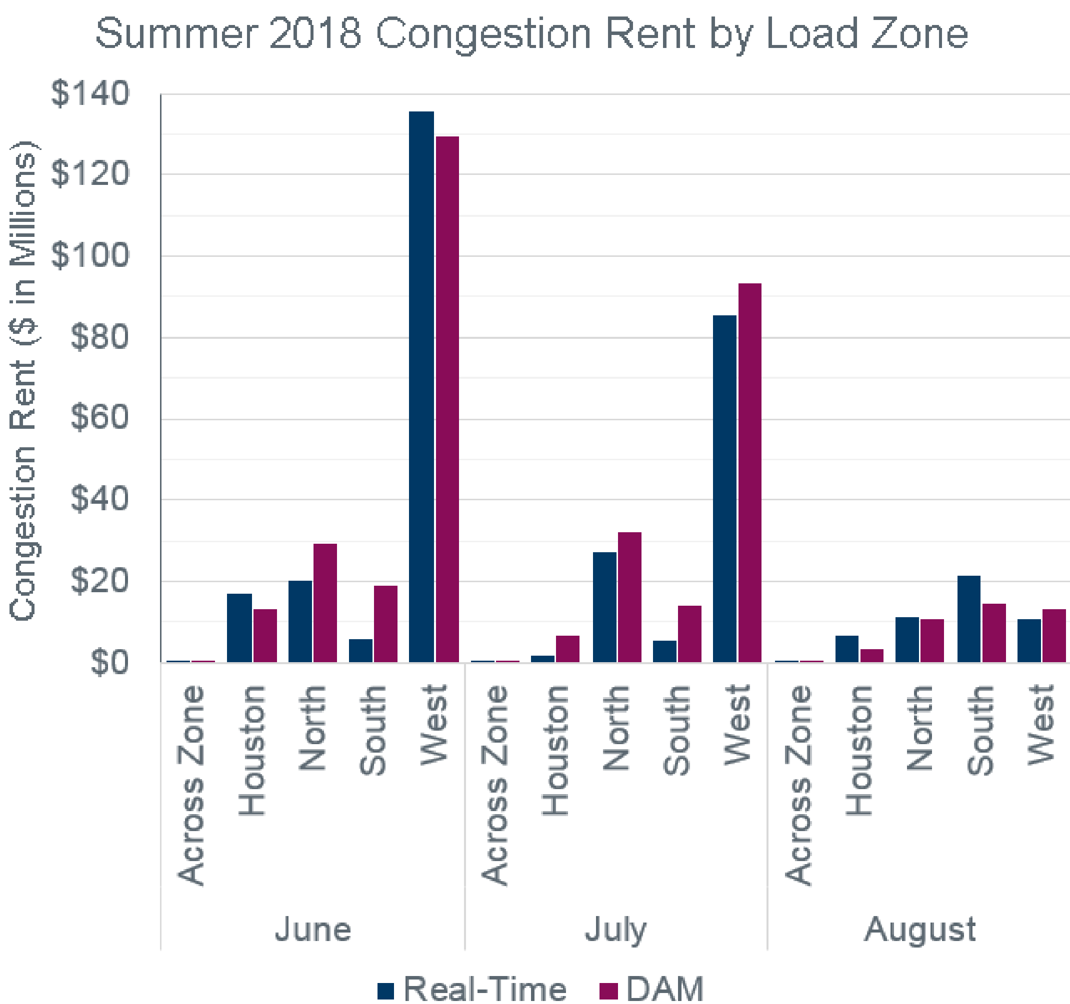
	2018 Actual Peak Demand (7/19/18)	Dec. CDR Summer 2018 Projection
Total Resources, MW	77,558	77,218
Thermal and Hydro	65,200	65,388
Private Use Networks, Net to Grid	3,019	3,341
Switchable Generation Resources	3,057	2,672
Wind Capacity Contribution	4,229	4,191
Solar Capacity Contribution	1,136	1,120
Non-Synchronous Ties	917	389
Peak Demand, MW	73,308	72,974*
Demand Reduction: ERS*	793**	979
Demand Reduction: LRRS	1,291***	1,119
Demand Reduction: TDSP Load Mgmt.	203****	203
Reserve Margin		9.3%

Source: Capacity Demand and Reserves Report December 2017
* Summer Peak Demand in the CDR is normalized for weather
** 2018 actual ERS value is the realized procurement amount, adjusted by 2% for avoided transmission losses.
*** 2018 actual LRRS value is the latest LR reserves obligation based on the Ancillary Services Requirements methodology, adjusted by 2% for avoided transmission losses.
**** The amount of actual load management by TDSPs during peak demand day in 2018 was assumed to be consistent with CDR assumptions to allow for comparison.

Additional topics and days of interest

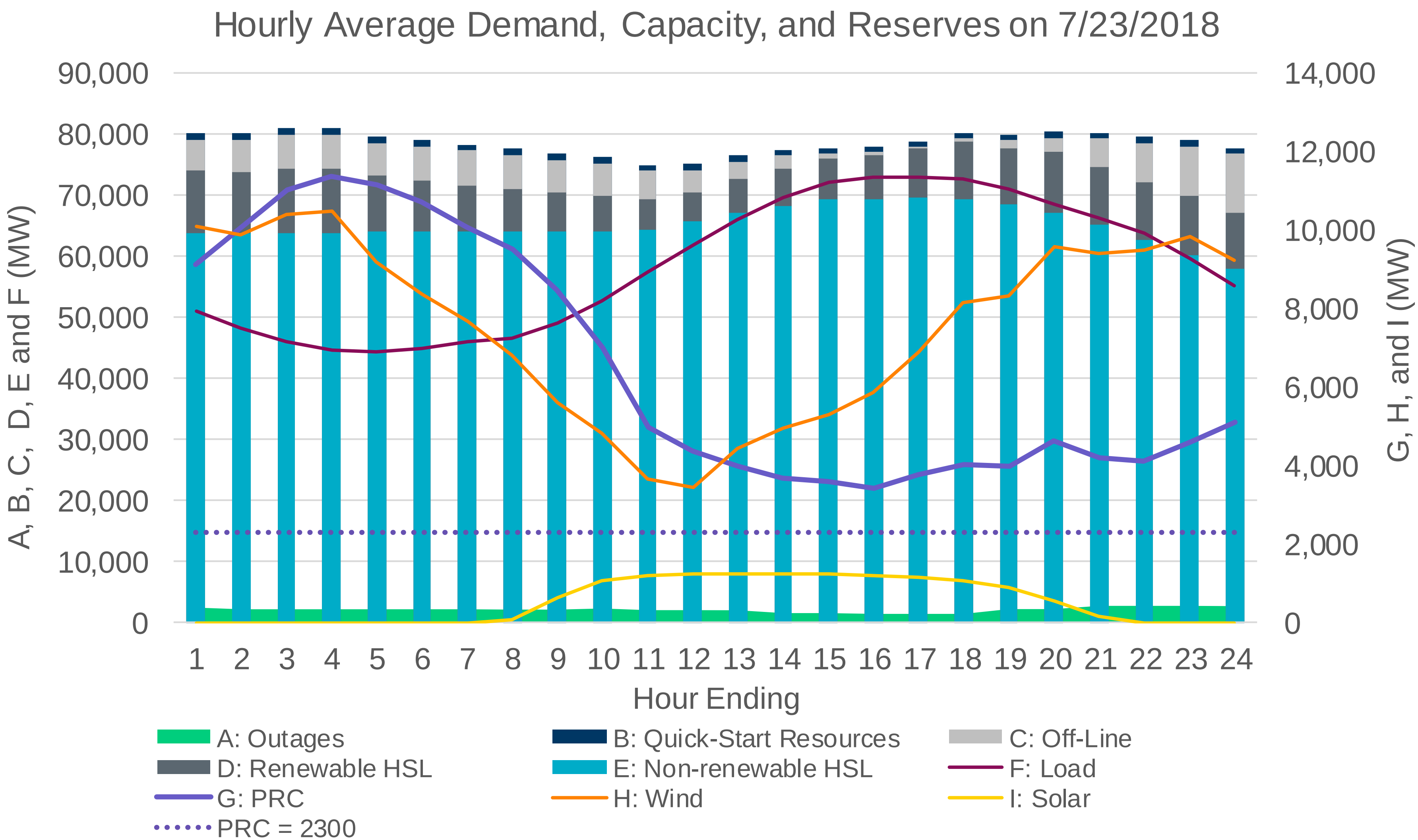
- The remaining material includes information on other topics and days of interest that occurred during summer 2018.
  - Congestion in West Texas
  - Days that illustrate the impacts of varying operating conditions, other than the peak demand day (July 19)
    - July 23 – Day with high system-wide prices in the DAM that did not materialize in Real-Time
    - August 2 – Day in which a significant reserve capacity shortage was projected, resulting in the need for RUC instructions
    - August 18 – Day with the lowest operating reserves due to generation forced outages near peak conditions

Significant congestion in West Texas



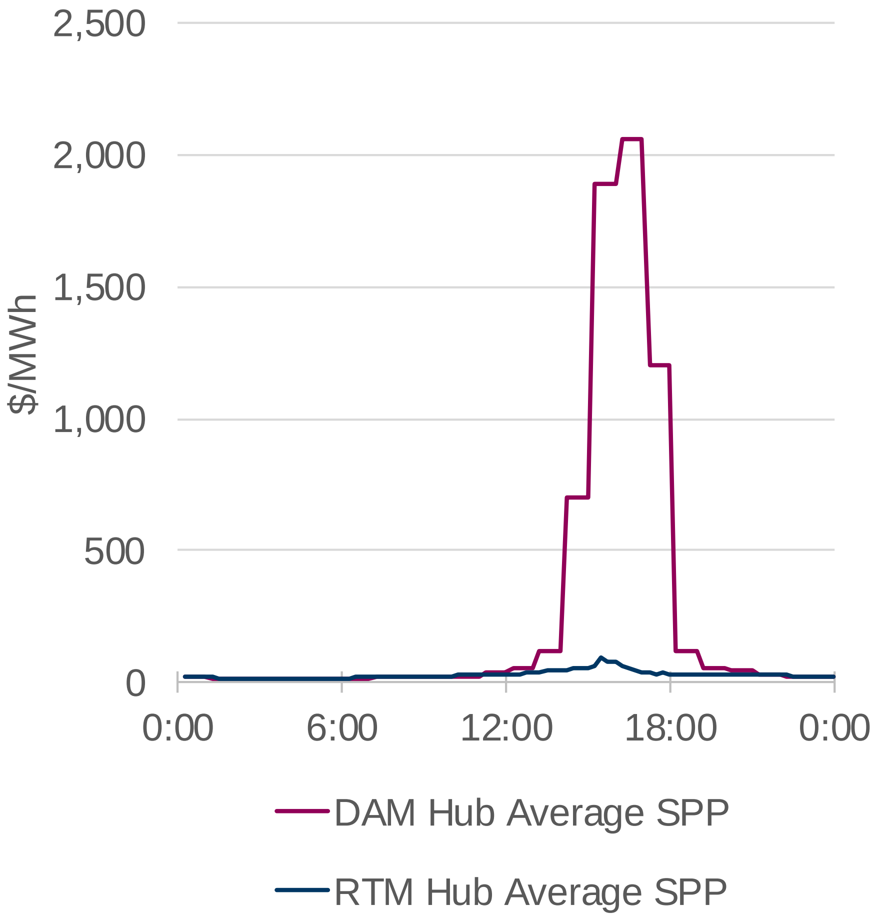
- West Load Zone congestion was particularly prevalent in June and July, both in Real-Time and the DAM.
- This congestion also occurred in May and was not specific to summer conditions.
- Driven by high industrial load with lack of resources to resolve when solar generation is not available.
- Energization of a new 138-kV line in late July helped mitigate the constraints that were being observed.
  - One line section of the new line from Wolf Switching Station to Wickett and another from Wickett to Pyote TNP

A closer look at July 23



*Off-line capacity is a summation of capacity from resources that were simply off-line and those providing non-spinning reserves as an off-line resource.

For July 23, system-wide SPPs across the peak hours were much higher in the DAM, relative to Real-Time



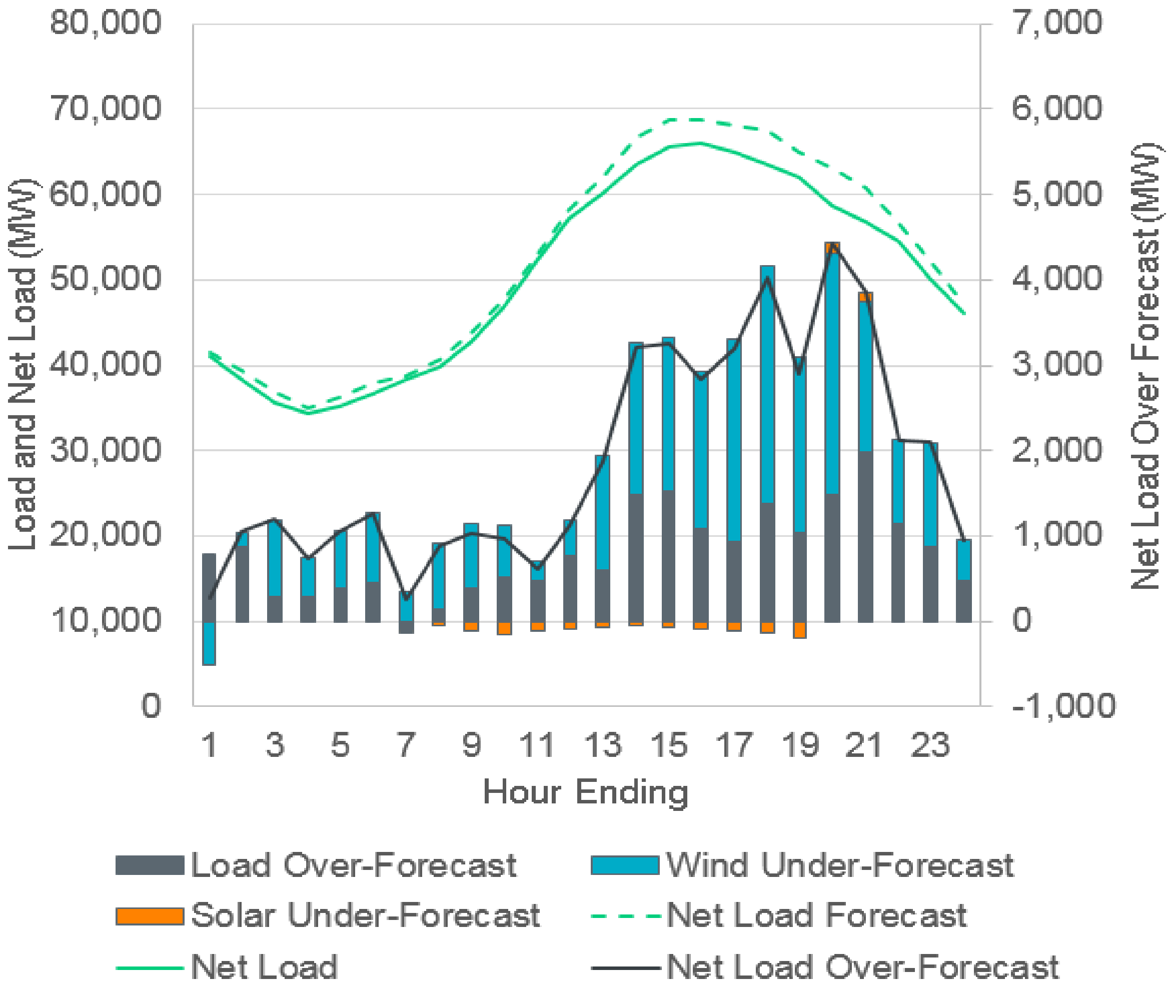
- On July 23, 2018, system-wide prices in the DAM exceeded $2,000/MWh, while the Real-Time prices did not exceed $100/MWh.

- Like July 19, the 23rd had very few resources that were off-line and available as well as few resources that were on outage.

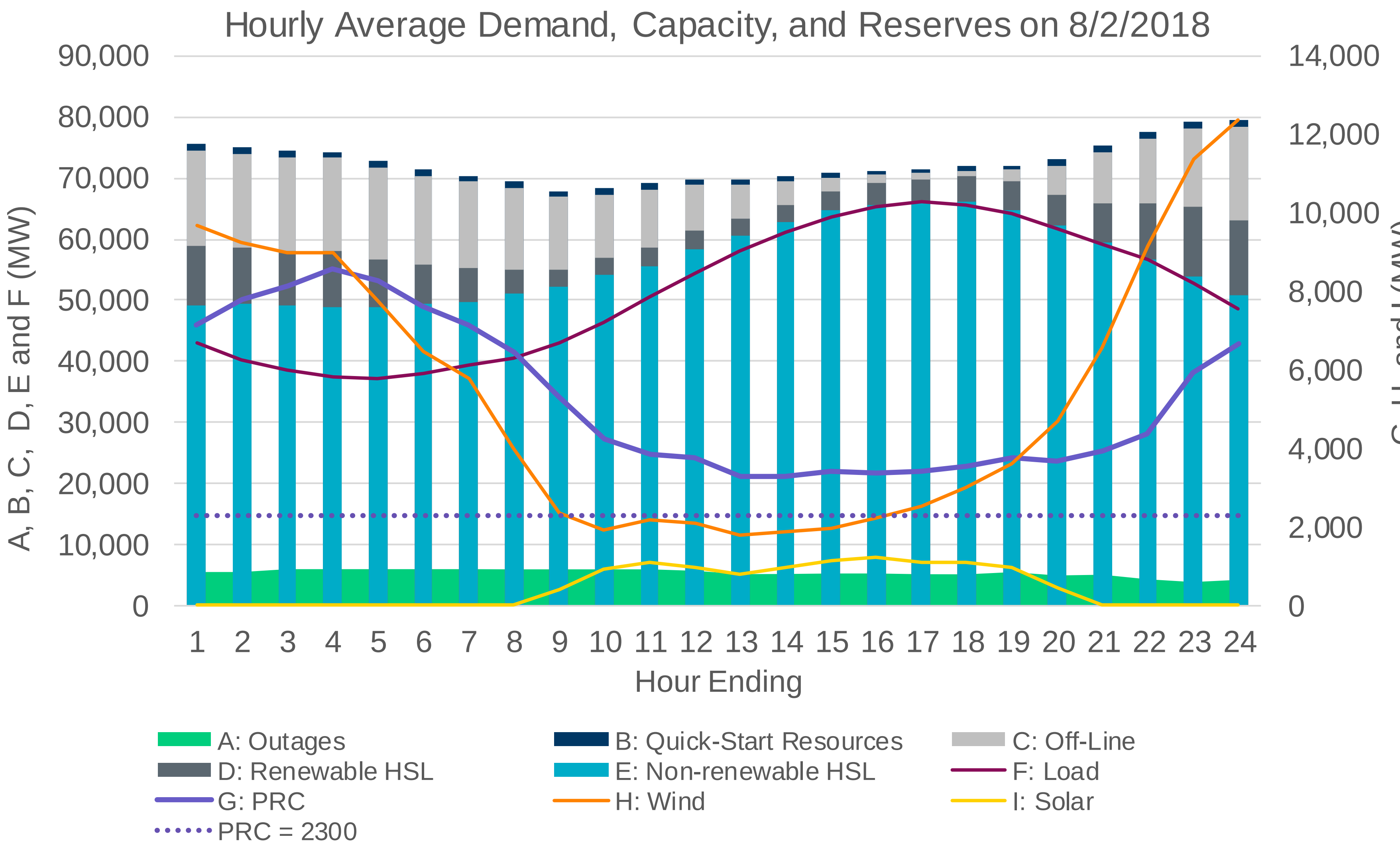
Conditions for July 23 were less tight than originally anticipated by ERCOT and market participants

- The observed net load in Real-Time was less than what was forecasted at the time of DAM executing.

- These forecasts are not directly used by ERCOT or market participants in the DAM, but give an indication of what was expected for July 23.



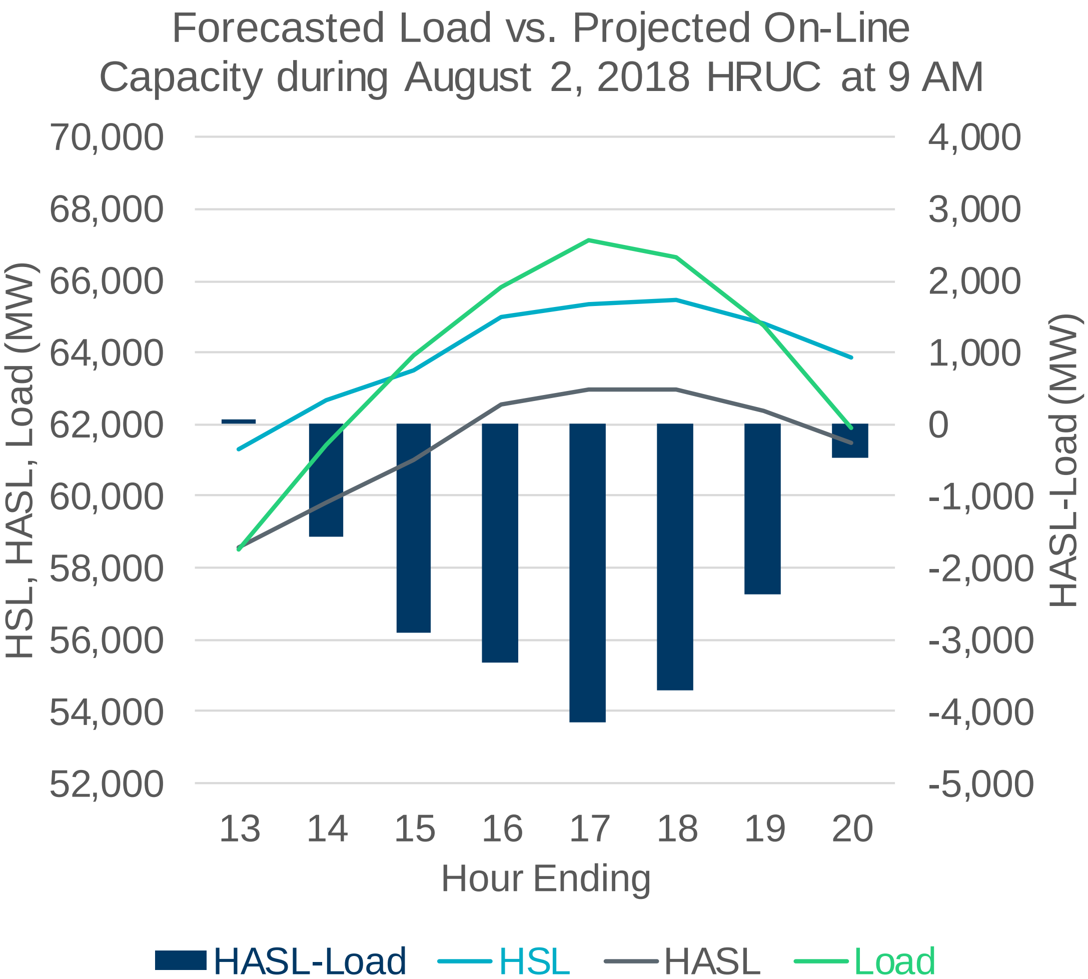
A closer look at August 2



*Off-line capacity is a summation of capacity from resources that were simply off-line and those providing non-spinning reserves as an off-line resource.

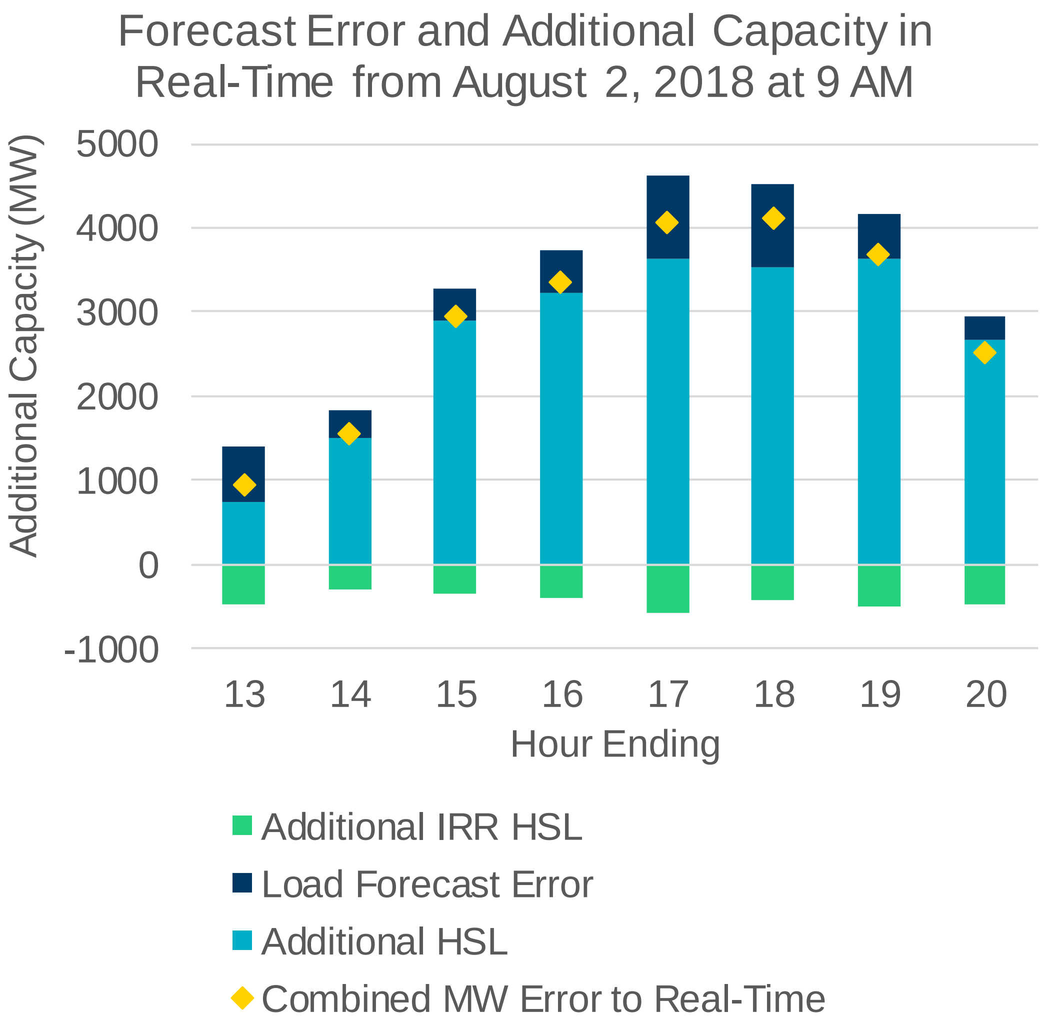
Projected reserve capacity for the RUC instructions on August 2

- ERCOT was projecting a reserve capacity shortage and issued an Operating Condition Notice on August 1 at 9:59 p.m.
- 4,142 MW short for hour ending 17 – 972 MW and 739 MW committed at 9 a.m. and 10 a.m., respectively
  - Not all capacity was committed for the same hours.
- 29 and 24 additional resources were recommended by RUC for commitment at 9 a.m. and 10 a.m., respectively, but were deferred by the operator.



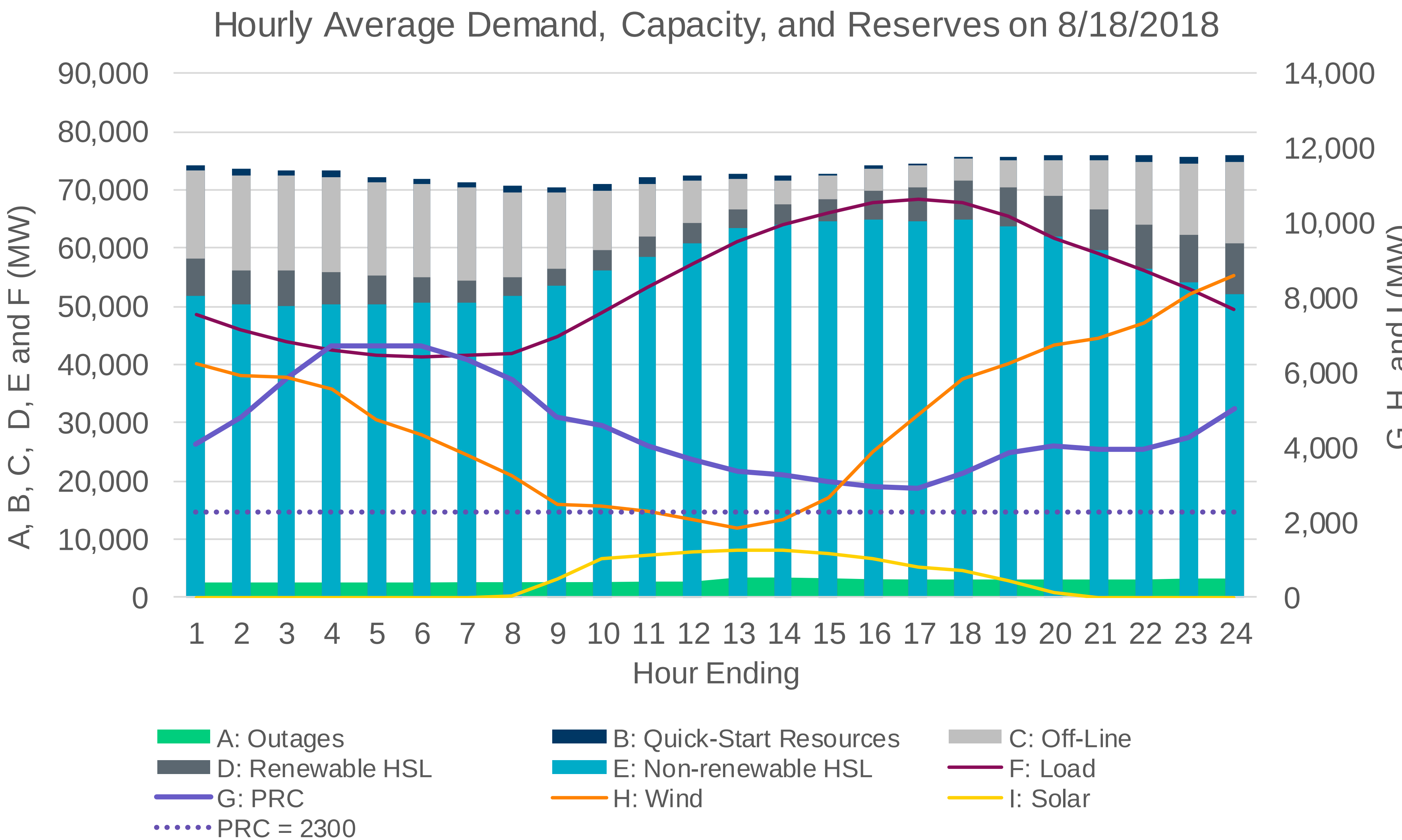
- High Sustained Limit (HSL) describes the maximum sustained capacity available from resources.
- High Ancillary Service Limit (HASL) is the HSL of resources less the capacity being reserved to provide Ancillary Services.

More reserve capacity available in Real-Time than projected at the time of the RUC instructions on August 2



- Primary driver for the increases between projected and actual reserve capacity was market participants committing resources that were planned to be off-line.
  - This trend was not necessarily prevalent through all of June, July and August.
- System-wide load and the capacity available from IRRs were both over-forecasted.
  - Over-forecasting of load results in additional reserve capacity being available.
  - Over-forecasting of IRR capacity results in less reserve capacity being available.

A closer look at August 18



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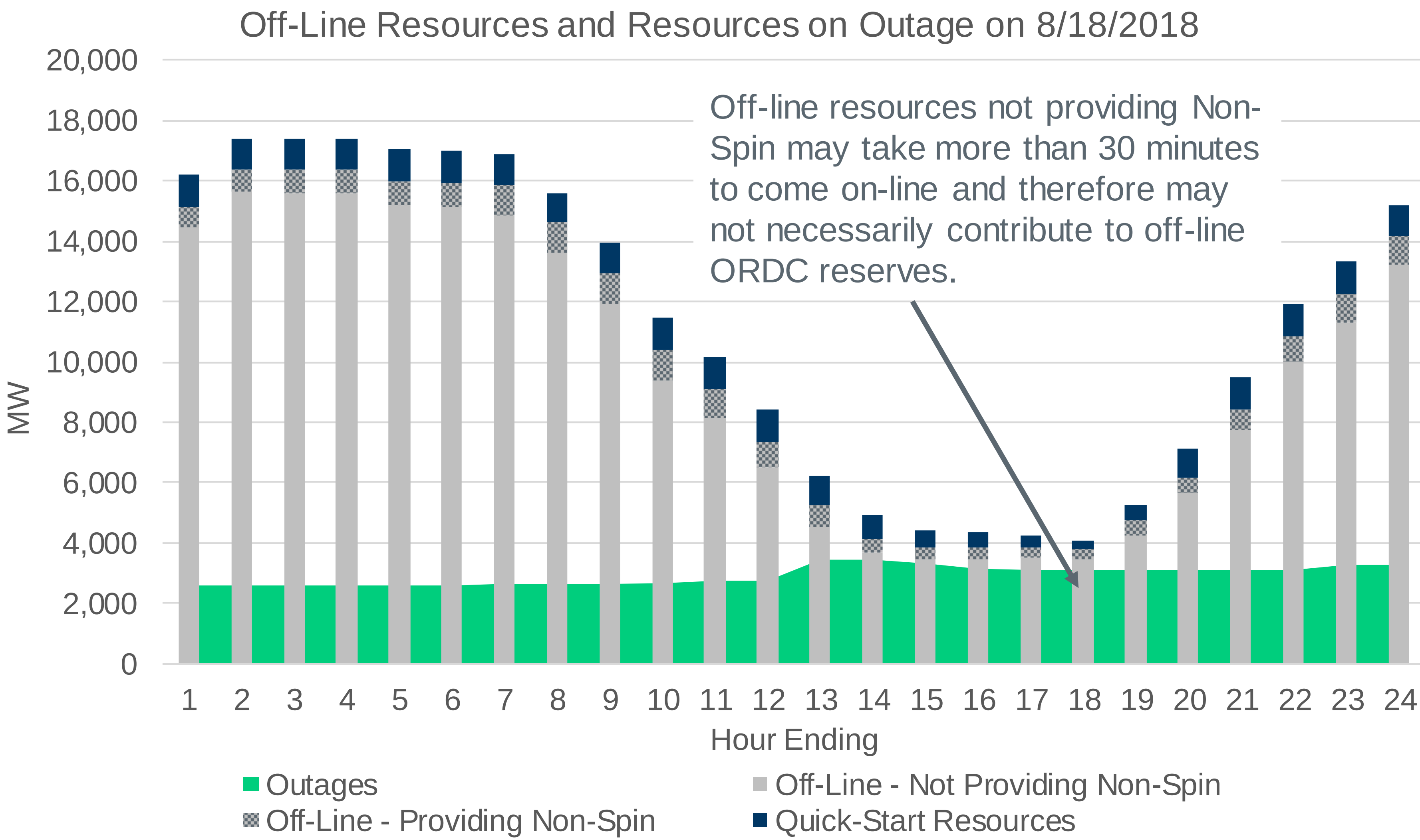
Off-line and available resource capacity on August 18



ORDC reserves and prices adders on August 18

- The highest ORDC price adders occurred on August 18, 2018, with the On-Line ORDC Price Adder exceeding $1,400/MWh for a single SCED interval.
  - Two significant generator trips occurred on August 18, one just prior to peak demand.
- This day was a Saturday.
- PRC values reached ~2,500 MW following a unit trip in the afternoon, just prior to peak demand.