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July 15, 2019

VIA ETARIFF

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Virginia Electric and Power Company Response to June 14, 2019 Deficiency Letter; Docket No. ER19-1661-001

Dear Secretary Bose:

On April 24, 2019, Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("Dominion") submitted to the Federal Energy Regulatory Commission ("Commission") in the above-captioned docket proposed tariff revisions to the PJM Interconnection, L.L.C. Open Access Transmission Tariff ("Tariff") to incorporate a new Attachment M-2.

The proposed Attachment M-2 changed the calculation of the Network Service Peak Load contribution ("NSPL") for each Load Serving Entity ("LSE") within the Dominion Zone. The NSPL calculation is used to determine each LSE's load ratio share of Dominion's Annual Transmission Revenue Requirement ("ATRR"). Specifically, Dominion proposed that Attachment M-2 will include a new twelve month coincident peak ("12-CP") allocation feature to reduce cost shifts related to annual peak seasonal changes, and reduce the incentive for LSEs to shift costs to other transmission customers by reducing consumption at the peak hour in order to reduce or avoid Network Integration Transmission Service ("NITS") and other charges under the PJM Tariff.

On June 14, 2019 the Commission Staff requested complete responses to several questions in order to process Dominion's proposal. Dominion is submitting the requested responses to Staff's questions with this filing.[1]

[1] Pursuant to Order No. 714, this filing is submitted by PJM on behalf of Dominion as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over its tariff. Thus, Dominion has requested that PJM submit this Attachment M-2 in the eTariff system as part of PJM's electronic Intra PJM Tariff.

I. EXECUTIVE SUMMARY

As an initial matter, based on the questions asked, Dominion reiterates that the filing proposed a 12-CP cost allocation feature to reduce yearly volatility in the transmission charges to customers within the Dominion Zone, and to stabilize cost allocation between Network Customers due to changes in Dominion's annual system peak including cost-shifting between customers.[2]

Dominion did not propose any change to its Attachment H-16A formula rate, where the 1-CP demand remains the divisor in Dominion's formula rate. To be clear, Dominion's proposal in this docket does not change the rate for NITS in the Dominion Zone. The sum of all Network Customers' NSPLs will continue to equal the 1-CP demand devisor included in the formula rate.[3] Instead, Dominion's 12-CP allocation feature proposes a change to how the costs between Network Customers (including LSEs) are allocated. To ensure that the costs for utilizing the benefits of the transmission grid are allocated fairly between Network Customers/LSEs (*i.e.*, those customers that utilize and benefit from Dominion's transmission system), Dominion proposed to look at its Network Customers load during each of the Dominion Zone's twelve-monthly peaks instead of at just the 1-CP each year. As clearly demonstrated by the data provided in Exhibits DEV-6 and DEV-7, Network Customers that are able to curtail their load during the 1-CP have reduced their allocated NITS costs and shifted those costs to other customers. Dominion's 12-CP proposal evens out this allocation by using loads during each monthly peak, thereby allowing the NITS costs to be allocated based on a much broader range of system usage conditions throughout the year instead of using only the 1-CP that is based on an hour snapshot.

Dominion appreciates the opportunity to provide additional information to the Commission and believes it clearly shows the proposed 12-CP cost allocation feature is just and reasonable and should be accepted by the Commission.

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2 *See* Exhibit No. DEV-1 at 9:14-22, 10-11; Exhibit No. DEV-4, Table 3 (showing, for example, that Network Customer A's load ratio share cost responsibility decreased by 38.4% from the 2016 rate year—a winter peaking year—to the 2017 rate year—a summer peaking year—but increased by 71.6% from the 2017 rate year to the 2018 winter peaking rate year).

3 *Id.* at 15:9-18.

II. RESPONSES TO QUESTIONS

Question 1(a):

Order No. 888 states that utilities "are free to file another [load ratio allocation method of pricing network service] if they demonstrate that it reflects their transmission system planning."

a. Please explain how the proposed 12-CP method reflects the way Dominion plans its transmission system, and why this proposal merits a different approach to the current 1-CP calculation method.

Response:

Dominion proposed the 12-CP allocation feature to reduce yearly volatility in the transmission charges to its Network Customers/LSEs due to seasonal peak changes, as the Dominion Zone has experienced both summer and winter 1-CP peaks over the past five (5) years. In addition, the proposed 12-CP allocation prevents cost shifting between Network Customers/LSEs within the Dominion Zone.

That being said, because of the growth of renewable resources, changes in capacity mix, and replacement of aging transmission infrastructure, Dominion's transmission planning has changed and evolved over the past five (5) years. Dominion, like many utilities, traditionally performed transmission planning in a manner to ensure reliability for all load levels that would occur during the year but with an emphasis on summer and/or winter peak loading periods. Up until the last five years, the actual annual peaks in the Dominion Zone were typically summer peaks and accordingly PJM forecasted annual peaks that were summer peaks for the Dominion Zone. However, over the last four out of five years the actual annual peaks have been winter peaks. Even though PJM's current forecast for DOM (the Dominion Zone) over the next ten years shows annual peaks that are all summer peaks, PJM also considers the winter peaks in transmission planning.[4] Prior to the growth in renewable resources and the retirement of traditional fossil fuel generation, planning for either a winter or summer peak was the predominant method to assess system reliability and determine the need for transmission projects in line with 1-CP methodology—which is still utilized to determine Dominion's NITS rate. However, over the last five years this philosophy has evolved so that planning assessments now factor in additional load periods other than system peak conditions. Given the impact from: (1) the growth of renewable resources, (2) the growth of distributed energy resources, (3) the change

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[4] *See* PJM RESOURCE ADEQUACY PLANNING DEP'T, 2019 LOAD FORECAST REPORT, 43, 47 (2019) https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx?la=en ("PJM 2019 Load Forecast Report") (Tables B-1 and B-2 show Summer Peak Load and Winter Peak Load forecasts for DOM (the Dominion Zone)); PJM TRANSMISSION PLANNING DEP'T, PJM MANUAL 14B: PJM REGION TRANSMISSION PLANNING PROCESS, Section 2.3.13 (2019), https://www.pjm.com/-/media/documents/manuals/m14b.ashx ("PJM Manual 14B") (Winter Peak Reliability Analysis).

in capacity mix due to retirement of older coal units and additions of gas-fired and renewable resources, and (4) the replacement of aging transmission infrastructure; planning for just a summer and/or winter peak no longer captures all of the reliability needs necessary to meet these dynamic and changing system conditions for other loading periods of the year.

PJM's transmission planning has also changed due to these same factors.[5] PJM and its stakeholders (including Dominion) recognize the reliability challenges associated with light load periods and have modified PJM's RTEP Process to incorporate light load methodology and power flow cases and potential new project drivers. The significant growth in renewable resources including wind and solar, coupled with the retirement of fossil fuel generators has required the need to fully assess other load periods beyond the summer and winter peaks.[6]

PJM's 2019 PJM Load Forecast demonstrates the growing distributed solar generation development across the grid.[7] The growth of distributed generation creates operational challenges that can require transmission upgrades. For example, renewable additions on the distribution system are growing at such a rapid pace that in many cases the additional generation plugging into the system is larger than the load being served which results in backflow onto the transmission system. Planning for this backflow during light load periods can require transmission upgrades. Additionally, data center growth has a high load factor which influences year-round monthly peaks.[8]

Moreover, during light load periods renewable resources typically have higher capacity factors than during a traditional system peak. During the summer peak loading periods in PJM, solar has a capacity factor of around 38% while during other times of the day or during lighter load months of the year, solar can approach 100% of its capability as well as swing the other direction with zero output. Furthermore, while traditional large-scale fossil fuel was built and placed closer to load, renewable generation resources are being sited in areas further away from heavy

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5 *See* PJM 2018 REGIONAL TRANSMISSION EXPANSION PLAN, 6 (2019), https://www.pjm.com/-/media/library/reports-notices/2018-rtep/2018-rtep-book-1.ashx?la=en ("PJM 2018 RTEP") (stating that PJM's Regional Transmission Expansion Plan ("RTEP") process manages an unprecedented capacity shift driven by federal and state public policy and broader fuel economics, including new generating plants powered by Marcellus and Utica shale natural gas, new wind and solar units driven by federal and state renewable incentives, generating plant deactivations, market impacts introduced by demand resources and energy efficiency programs).

6 *See* PJM 2018 RTEP at Tables 6.64 and 6.65 (showing for the Dominion Zone a significant change in generation resources with the retirement of older plants and growth of solar projects). The 2018 RTEP also shows at Tables 6.66 and 6.67 that most Dominion baseline projects in the RTEP are being driven by criteria other than load growth, deliverability and reliability.

7 *See* PJM 2019 Load Forecast at 64 (Table B-8, Distributed Solar Adjustments to Summer Peak Load Forecast by Zone and for the Total PJM RTO (50/50 Forecast)).

8 PJM 2019 Load Forecast at 2, 65 (Table B-9); PJM 2018 RTEP at 19 ("With reduced load growth and growing distributed technologies, the drivers for new transmission investment are shifting to those associated with the replacement of aging transmission infrastructure and attachment of new concentrated loads (e.g., new data centers).").

load centers and, in addition, cover a much broader geographic area with multiple points of interconnection. This disbursement of generation impacts the transmission system and must be considered as part of the planning process.

All of these changes to the grid have resulted in Dominion planning more transmission level projects to address aging infrastructure and light loading issues than transmission projects that are necessary to address traditional peak loading periods. For example, over the last several years, Dominion has installed approximately twenty (20) 230 kV/125 MVAR shunt reactors, as well as several dynamic STATCOM devices to help maintain system voltage during the lighter load periods. Further complicating the planning process is that generation and transmission maintenance and construction activity would typically occur during these lighter-load times, however, with the changes to the grid, Dominion has had to adjust the planning for its maintenance and construction activity.

As renewables grow in numbers, the transmission planning process must shift to model and assess the system in a manner more in line with real-time operations, looking at every hour of the day for the entire year. The PJM Region Transmission Planning Process contained in PJM Manual 14B requires studies that are more in depth than just a 1-CP analysis. For example, PJM Manual 14B requires transmission studies to include a:

- Baseline Thermal Analysis: a thorough analysis of the reference power flow to ensure thermal adequacy based on normal and emergency thermal ratings specific to the Transmission Owner facilities being examined.
    - Uses 50/50 load forecast from PJM Load Forecast Report (50% probability that the actual load is higher or lower than the projected load).[9]
- Load Deliverability Analysis: ensures that the Transmission System is adequate to deliver each load area's requirements from the aggregate of system generation.
    - Uses 90/10 load forecast from PJM Load Forecast Report – Stressed conditions with a forecast that only has a 10% chance of being exceeded.[10]
- Light Load Reliability Analysis: ensures that the Transmission System is capable of delivering the system generating capacity at light load.[11]

In other words, PJM's planning process requires a review that is well beyond just a 1-CP analysis. As demonstrated above, transmission planning considers peak loads in winter and

9 PJM Manual 14B at 38 (Section 2.3.6).

10 PJM Manual 14B at 41 (Section 2.3.9).

11 PJM Manual 14B at 43 (Section 2.3.11).

summer seasons, as well as light loads which are much closer in magnitude to the monthly peak load levels found in spring and fall than those found during the hour of the annual peak. Therefore, Dominion's proposed 12-CP allocation feature, which considers monthly peak usage in all seasons, reflects the way Dominion plans its transmission system.

Moreover, and as stated above, Dominion is not proposing to change its 1-CP demand divisor in its formula rate. Rather, Dominion's proposed 12-CP allocation feature results in a more stable cost allocation by dampening cost shifts due to changes in the annual system peak. As described, Dominion's proposal is merited based on the planning and development of its transmission system.

Question 1 (b):

Order No. 888 states that utilities "are free to file another [load ratio allocation method of pricing network service] if they demonstrate that it reflects their transmission system planning."

b. **Please provide monthly peak demand values for the Dominion Zone and each customer's contribution to the Dominion Zone 1-CP hour for each month of the last 5 calendar years.**

Response:

Dominion has a formula rate for transmission service on file with the Commission, currently designated as Attachment H-16A to the PJM Tariff. Under the formula rate, the unit charge for Network Service in the Dominion Zone is calculated by dividing the annual transmission revenue requirement by the load in the Dominion Zone at the annual coincident peak (the "1-CP" calculation). The annual billing determinants for each customer are calculated in accordance with Section 34.1 of the PJM Tariff. That section assigns charges on an annual basis according to each "Network Customer's individual wholesale and retail customer Zone Network Loads (including losses) ***at the time of the annual peak*** of the Zone in which the load is located."[12] As stated, Dominion is not changing the 1-CP demand nor is it changing the rate for NITS.

Exhibit 1.b provides 5 years of monthly peak data for the Dominion Zone.

Question 2:

In Exhibit No. DEV-6 to its filing, Dominion shows that multiple customers reduced demand during the 2019 Dominion Zone 1-CP hour to date. Please provide data showing whether customers also reduced demand during the Dominion Zone 1-CP hour in previous years, including whether the same customer(s) reduces demand in different years. Please

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[12] PJM Tariff Section 34.1 (emphasis added).

also provide the percentage reduction of each customer's demand during the 1-CP peak as compared to the next highest demand day.

Response:

Exhibit 2(a) shows the activity of the Customers in Exhibits DEV-6 and DEV-7 at the time of the Dominion Zone's 1-CP for 2015 through the 2019 year to-date.

Exhibit 2(b) includes a chart that compares the demand for each of the Customers listed in Exhibits DEV-6 and DEV-7 at the time of the Dominion Zone's 1-CP peak hour to what their demands were during the Zone's next highest peak demand hour. Listed in the table are both the Zone's 1-CP hour and its next highest peak demand hour for 2015 through 2019 year-to-date. The resulting percentage change in demand for each Customer between these two hours is then shown below their name in the table. While Dominion is including this chart as requested in the question, Dominion does not believe that this requested chart provides useful data. In particular, the chart does not provide an accurate representation of a Customer's ability to curtail load on the 1-CP since the magnitude of load on the 1-CP day does not equate to load on next highest peak day. In addition, several of the next highest peak days precede the 1-CP day and the Customers might have curtailed on both days and thereby distorted the relevance of the percentages shown in the table.

To better illustrate the cost shifting behavior of the Customers on the Dominion Zone's 1-CP day, Dominion also includes the chart in Exhibit 2(c) that compares the Customers' demand on the 1-CP to their non-coincident peak ("NCP") demand on the same day. Furthermore, the chart shows how the Customers behaved on the next four highest Dominion Zone peak days following the 1-CP day by comparing their demand at the time of the Zone's peak hour to their NCP. As clearly shown, for example, by Customer 3, it reduces demand on the 1-CP and makes no further reductions on the following peak days.

Question 3 (a):

In the filing, Dominion states that "[r]educing the incentive to curtail only at the system peak is appropriate because one-time yearly discretionary load reductions are unlikely to impact the need for additional transmission infrastructure on a long-term basis, and therefore are unlikely to result in transmission system cost savings."

> **a. Please explain what constitutes discretionary load reduction. Please explain how this is different than participating in a demand response program.**

Response:

In the context of Mr. Jackson's testimony, a discretionary load reduction is a voluntary load reduction that occurs during the hour of the Dominion Zone annual peak without direction from PJM to make such a reduction. Unlike the load management demand response programs described in part b to this question, the discretionary load reductions discussed in Mr. Jackson's testimony are not part of a PJM program designed to provide verified load reductions and capacity to the PJM system. Notably, in order to receive demand response capacity payments, demand resources are subject to PJM performance and testing requirements and are subject to penalties for unsatisfactory performance or test failures.

There were no PJM mandatory load management events from June 2014–January 2019. Therefore, any load management reductions by Dominion customers during this time period were voluntary.[13] The PJM non-mandatory compliance load management events that occurred in 2014 did not occur on January 30, 2014, which was the day of the 2014 Dominion Zone annual peak.

Question 3 (b):

> **b. Please provide information on the demand response program(s) in which customers who engage in load reductions participate, including voluntary and involuntary load reductions.**

Response:

See Exhibit 3.b.1 for a general overview of PJM demand response programs and see Exhibit 3.b.2 for a more detailed discussion of the specific PJM Demand Response programs that were the basis of Mr. Jackson's testimony on Page 13 lines 7–9 of Exhibit No. DEV-1, regarding the possible benefit of reducing load at the peak if needed. These exhibits show PJM's efforts to create a demand response program that is integrated into the power markets and receive payments for their response.

Question 3 (c):

> **c. For those customers that engaged in discretionary load reductions, please provide information on the frequency (number of times per year) and amount (MW) that those customers reduced demand for the last 5 years.**

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[13] *See* PJM LOAD MANAGEMENT PERFORMANCE REPORT 2018/2019 (2019), https://www.pjm.com/-/media/markets-ops/dsr/2018-2019-dsr-activity-report.ashx?la=en (showing PJM Load Management Performance events for the period June 2014 through January 2019); *see also* PJM EMERGENCY DEMAND RESPONSE (LOAD MANAGEMENT) PERFORMANCE REPORT 2013/2014 18-19 & Figure 15 (2014), https://www.pjm.com/-/media/markets-ops/dsr/2013-2014-dsr-activity-report-20140417.ashx?la=en.

Response:

Exhibit 3.c shows the reductions in 1-CP demand of the customers Dominion believes engage in discretionary load reductions during the last 5 years. It should be noted that Dominion does not have any measurement and verification procedures in place to determine the MW amount. Dominion estimated these percentage reductions as the percentage difference between each Customer's non-coincident peak demand and its coincident peak demand during the day of the Dominion Zone annual peak.

Question 4 (a):

In his testimony, Mr. Jackson acknowledges that "reducing load during the peak can be beneficial" but states that "there are no identifiable transmission cost savings that would accrue from Network Customers' discretionary load reductions at the time of the 1-CP." As explanation, Mr. Jackson offers only that these reductions are "discretionary" and that "[h]aving the load reduced during a single peak hour in one year does little to mitigate the need for transmission if it reappears during another single peak hour within a few years."

a. **Please explain Mr. Jackson's statement that reducing load can be beneficial but not in the Dominion Zone.**

Response:

Mr. Jackson's complete statement is found on Exhibit DEV-1 Page 13 lines 7-12 and is provided below:

> As a general matter, reducing load during the peak can be beneficial. That is why in PJM, for example, demand response providers can be compensated for agreeing to do exactly that, if needed. However, with the respect to transmission facilities in the Dominion Zone, there are no identifiable transmission cost savings that would accrue from Network Customers' discretionary load reductions at the time of the 1-CP.

When discussing the possible benefits of reducing load during a system peak, Mr. Jackson was referring to the PJM demand response program where PJM pays a capacity credit for the ability to direct the reduction of load, if it is needed, during a pre-emergency or emergency. Please see responses to 3a and 3b. Contrary to how this question is phrased, Mr. Jackson believes a PJM-directed reduction in load in any PJM zones, including the Dominion Zone, in response to an emergency or pre-emergency can be beneficial. When discussing the absence of identifiable transmission cost savings accruing from Network Customers discretionary load reductions at the time of the 1-CP, Mr. Jackson's statement was made in regards to Dominion's ability to identify any savings in the cost of constructing transmission facilities.

Question 4 (b):

> **b. Please provide data demonstrating whether customers reducing their demand during the 1-CP have, in fact, caused costs to be incurred for which they are able to avoid responsibility by reducing demand during the peak. Please be specific as to the type and magnitude of these costs.**

Response:

All Network Customers/LSEs that use Dominion's transmission facilities benefit from the facilities and, therefore, have caused a part of those costs to be incurred. To the extent Network Customers/LSEs have reduced load at the hour of the annual peak during the past five years Network Customers/LSEs have avoided NITS charges in the Dominion Zone that reflect transmission costs that were incurred by Dominion on their behalf and have shifted those costs to other Network Customers/LSEs in the Dominion Zone.

Approximate NITS charges avoided per MW of reduction at the annual peak set during the previous year ending October 31 are as follows:

2019	$47,471.44 / MW-Year
2018	$47,526.56 / MW-Year
2017	$47,375.56 / MW-Year
2016	$41,245.46 / MW-Year
2015	$42,902.23 / MW-Year

Question 4 (b) (i):

> **i. If customers that voluntarily reduce demand during the 1-CP cease to do so, please explain how that may affect transmission planning and cost allocation in the Dominion Zone.**

Response:

Dominion does not include a MW level for the voluntary demand reductions at the time of the 1-CP in its transmission planning. Accordingly, if Network Customers/LSEs cease to make voluntary demand reductions it would not have any identifiable impact on Dominion's transmission planning. To the extent such voluntary demand reductions during the 1-CP cease, Network Customers/LSEs that would have otherwise reduced load in the hour of the annual peak would pay the NITS Charge for a full calendar year, and no transmission costs would have been shifted to other Network Customers/LSEs.

Question 5 (a):

Mr. Jackson also states that: "Growth in the 1-CP is not the only driver impacting a transmission construction plan. Transmission planning must also consider and address distribution level solar growth, end of life of existing facilities, maintenance, light load issues causing high voltage on the system, and specific high demand customer hookups. These planning considerations are not relieved by a customer reducing its load during a single peak hour in one year."

Please explain:

a. **Whether these are the only costs Dominion alleges are shifted by discretionary load reduction.**

Response:

No. It is the cost (or charge) for NITS that is shifted. As noted above, Dominion's NITS rate is not being altered by its filing in this docket. Instead, as explained, Dominion is seeking to change the method by which the costs are allocated between Network Customers/LSEs.

Question 5 (b):

b. **The magnitude of these costs relative to other transmission planning costs.**

Response:

As discussed in 5.a., it is not transmission planning costs that are being shifted but rather the cost for NITS that is being shifted. All transmission related costs that Dominion has incurred are incorporated in its rate for NITS. The NITS rate includes all transmission plant in service, which includes all categories of transmission costs, but excludes, for example, step-up transformers and interconnection facilities. The approximate $ /MW-year annual transmission revenue requirement associated with these NITS costs are shown in the response to 4.b.

Question 5 (c):

c. **Whether these costs are incurred irrespective of use.**

Response:

The transmission costs that are included in Dominion's rate for NITS have been incurred for facilities in service, or projected to be in service, during the applicable calendar year the rate is charged. Dominion incurred the transmission costs included in its rate for NITS in order to provide safe and reliable transmission service to all transmission customers. A Network

Customer reducing it usage during the 1-CP does not reduce these costs. Instead, reducing usage at the 1-CP simply shifts costs to other Network Customers/LSEs.

Question 6:

Please provide data demonstrating how many customers would be impacted by the proposed change and the magnitude of the impact resulting from the change in cost allocation under the current and proposed NSPL methods.

Response:

Exhibit No. DEV-4 Page 1 Table 2 provides the load ratio shares calculated based on the current method.

Exhibit No. DEV-4 Page 2 Table 5 provides the load ratio shares calculated based on the proposed method.

These tables show the impact for Network Customers A-F and J who contribute approximately 100% of Dominion's 1-CP load. Customers G-I began serving load after the annual peak used to determine 2019 load ratio shares was established and, as a result, Dominion does not have a complete set of data for them to compare current versus proposed load ratio shares.

III. CONCLUSION

WHEREFORE, Dominion respectfully requests that the Commission accept the additional information included in this submittal; accept the proposed Tariff revisions included in Dominion's April 24 Filing, and permit an effective date of January 1, 2020.

Respectfully submitted,

/s/ Amie V. Colby

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Counsel for Dominion Energy Virginia

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the parties identified on the Commission's official service list for this proceeding.

Dated at Washington, D.C., this 15th day of July, 2019.

/s/ Katherine J. O'Konski

Katherine J. O'Konski
TROUTMAN SANDERS LLP
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Exhibit 1(b)

Month	DATE	HE	CVEC	NCEMC	NVEC	ODEC	SEPA	APNDOM	CCEDOM	MP2DV2	SESDOM	DOMLSE	TOTAL
1	01/30/14	08	187	334	795	1,533	103					16,831	19,784
2	02/12/14	08	153	274	730	1,232	103					15,040	17,532
3	03/04/14	08	172	286	731	1,345	103					15,002	17,639
4	04/17/14	08	95	184	481	782	105					10,337	11,983
5	05/13/14	17	83	229	792	800	103					14,228	16,235
6	06/18/14	18	101	287	942	1,000	103					16,003	18,434
7	07/02/14	16	104	280	949	1,016	103					16,240	18,692
8	08/21/14	15	76	261	751	838	103					14,206	16,234
9	09/02/14	17	99	289	862	969	103					15,972	18,293
10	10/14/14	20	56	179	555	585	103					10,766	12,244
Average			**113**	**260**	**759**	**1,010**	**103**					**14,462**	**16,707**

Month	DATE	HE	CVEC	NCEMC	NVEC	ODEC	SEPA	APNDOM	CCEDOM	MP2DV2	SESDOM	DOMLSE	TOTAL
11	11/19/14	08	147	272	684	1,140	103					13,853	16,199
12	12/31/14	08	133	235	612	1,036	105					12,614	14,735
1	01/08/15	08	188	353	809	1,471	103					16,946	19,870
2	02/20/15	08	202	383	857	1,681	103					18,424	21,651
3	03/06/15	08	153	287	720	1,245	106					15,209	17,719
4	04/02/15	08	78	187	461	705	104	20				10,191	11,745
5	05/19/15	17	82	213	790	796	103	27				13,805	15,815
6	06/23/15	17	106	300	932	1,018	103	27				16,493	18,980
7	07/20/15	17	105	293	911	997	103	26				16,112	18,547
8	08/04/15	17	100	272	890	986	103	26				15,550	17,928
9	09/09/15	17	87	248	845	916	103	24				14,942	17,165
10	10/19/15	08	93	189	545	800	103	18				10,483	12,231
Average			**123**	**269**	**755**	**1,066**	**103**	**24**				**14,552**	**16,882**

Month	Date	Time	CVEC	NCEMC	NVEC	ODEC	SEPA	APNDOM	CCEDOM	MP2DV2	SESDOM	DOMLSE	TOTAL
11	11/24/15	08	106	237	561	909	104	18				11,988	13,923
12	12/04/15	08	120	185	574	957	105	17				11,411	13,370
1	01/19/16	08	171	313	797	1,381	104	19				16,164	18,948
2	02/14/16	08	179	319	766	1,418	104	19				15,325	18,131
3	03/03/16	08	121	204	621	968	104	16				12,339	14,373
4	04/06/16	08	105	208	589	892	104	16				11,687	13,601
5	05/27/16	17	90	210	846	790	103	21				13,493	15,553
6	06/16/16	18	111	251	827	943	103	20				14,152	16,407
7	07/25/16	17	113	306	1,031	1,066	103	21				16,899	19,538
8	08/13/16	17	110	302	1,052	1,192	103	21				16,313	19,092
9	09/09/16	17	101	259	973	1,056	103	20				15,399	17,911
10	10/19/16	17	66	184	695	673	103	19				12,187	13,927
Average			**116**	**248**	**778**	**1,020**	**103**	**19**				**13,946**	**16,231**

Exhibit 1.b **Dominion Docket No. ER19-1661**

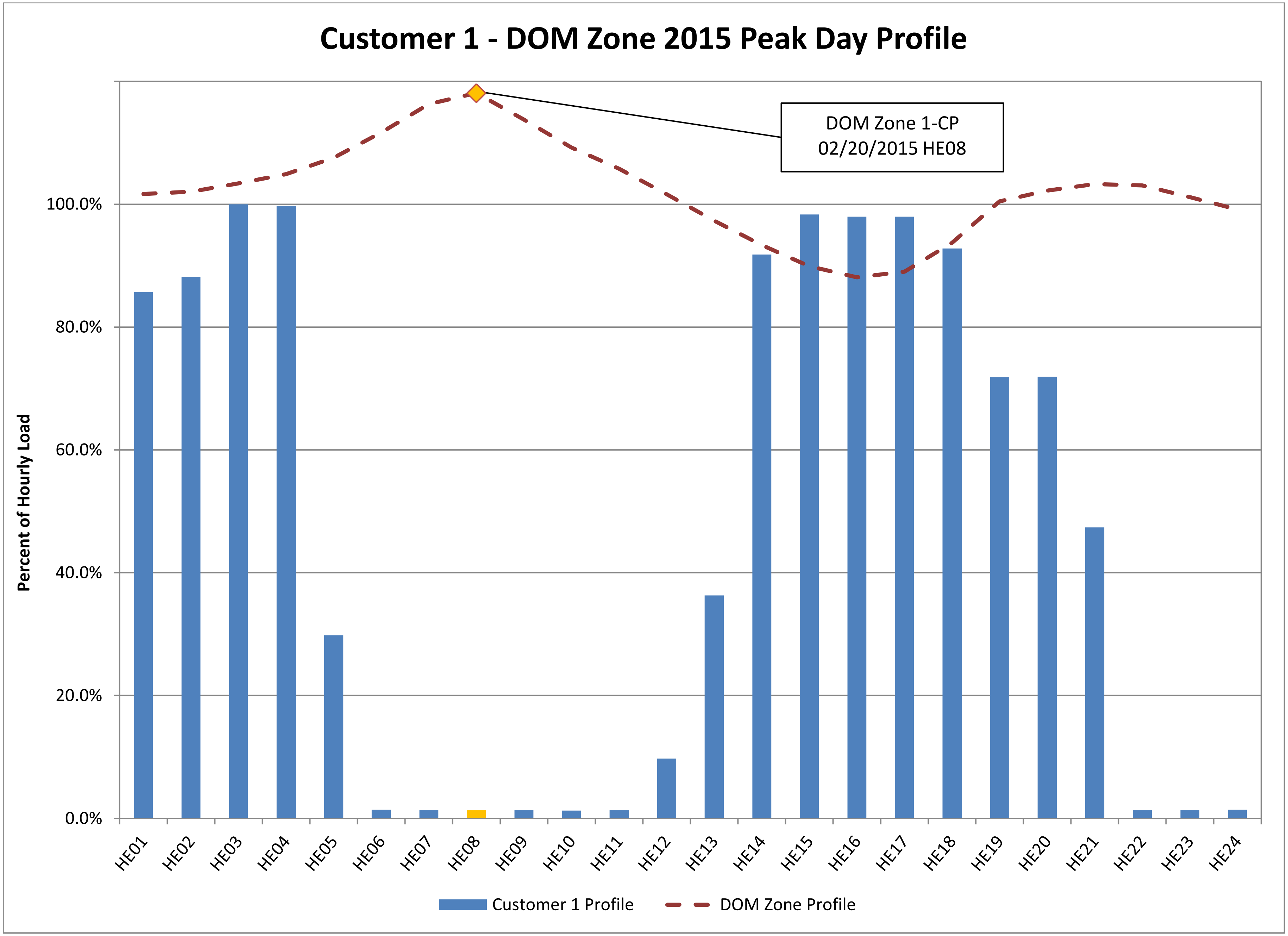
Month	Date	Time	CVEC	NCEMC	NVEC	ODEC	SEPA	APNDOM	CCEDOM	MP2DV2	SESDOM	DOMLSE	TOTAL
11	11/22/16	08	112	230	601	984	103	15				12,385	14,429
12	12/16/16	08	160	281	803	1,300	103	14				15,477	18,138
1	01/09/17	08	194	336	838	1,568	103	14				16,609	19,661
2	02/10/17	08	140	241	716	1,160	103	13				14,016	16,389
3	03/15/17	08	141	267	711	1,200	103	14				14,689	17,124
4	04/29/17	17	99	218	786	867	106	19				12,697	14,791
5	05/19/17	16	88	216	896	826	103	19				14,149	16,297
6	06/13/17	16	96	236	968	932	103	20				15,109	17,463
7	07/14/17	16	119	291	1,012	1,029	103	19				16,330	18,902
8	08/18/17	16	113	279	1,014	1,006	103	21				15,935	18,470
9	09/27/17	17	98	202	892	827	103	19	1			13,684	15,826
10	10/09/17	17	95	202	835	768	103	19	1			13,207	15,229
Average			**121**	**250**	**839**	**1,039**	**103**	**17**	**1**			**14,524**	**16,893**

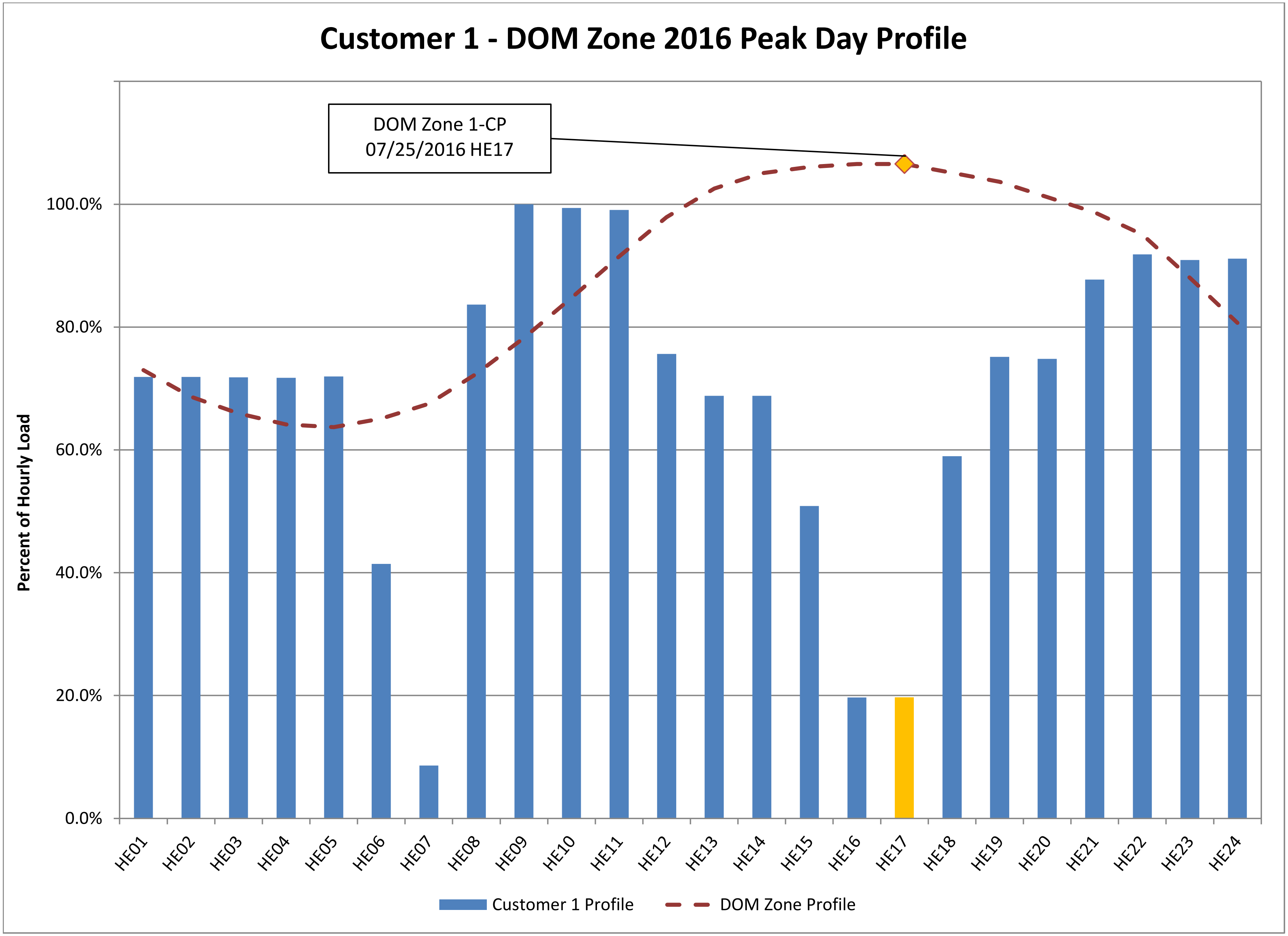
Month	Date	Time	CVEC	NCEMC	NVEC	ODEC	SEPA	APNDOM	CCEDOM	MP2DV2	SESDOM	DOMLSE	TOTAL
11	11/27/17	08	96	207	642	887	103	15	1			11,610	13,560
12	12/28/17	08	165	291	831	1,320	103	15	1			15,273	17,999
1	01/07/18	08	215	404	931	1,788	103	16	1			17,776	21,232
2	02/03/18	08	166	274	844	1,356	103	15	1		6	14,699	17,463
3	03/15/18	08	114	239	690	989	103	15	1		9	13,229	15,389
4	04/11/18	08	83	184	644	758	103	15	2		7	10,845	12,640
5	05/15/18	17	89	206	926	799	103	20	2		11	13,681	15,837
6	06/19/18	14	101	266	1,070	1,020	103	21	3		11	15,708	18,303
7	07/02/18	17	102	288	1,110	1,074	103	21	3	18	5	16,519	19,244
8	08/29/18	17	98	270	1,099	1,036	103	20	3	16	5	16,273	18,924
9	09/06/18	17	93	265	1,162	1,023	103	20	2	22	16	15,897	18,604
10	10/04/18	17	77	229	939	837	103	20	2	18	21	14,028	16,274
Average			**117**	**260**	**907**	**1,074**	**103**	**18**	**2**	**19**	**10**	**14,628**	**17,122**

Month	Date	Time	CVEC	NCEMC	NVEC	ODEC	SEPA	APNDOM	CCEDOM	MP2DV2	SESDOM	DOMLSE	TOTAL
11	11/29/18	08	137	241	778	1,032	104	15	3	19	17	13,225	15,571
12	12/11/18	08	154	216	868	1,242	104	16	2	14	19	13,853	16,490

Exhibit 2(a)

Exhibit 2(a) Docket No. ER19-1661




Customer 1 - DOM Zone 2016 Peak Day Profile
DOM Zone 1-CP
07/25/2016 HE17
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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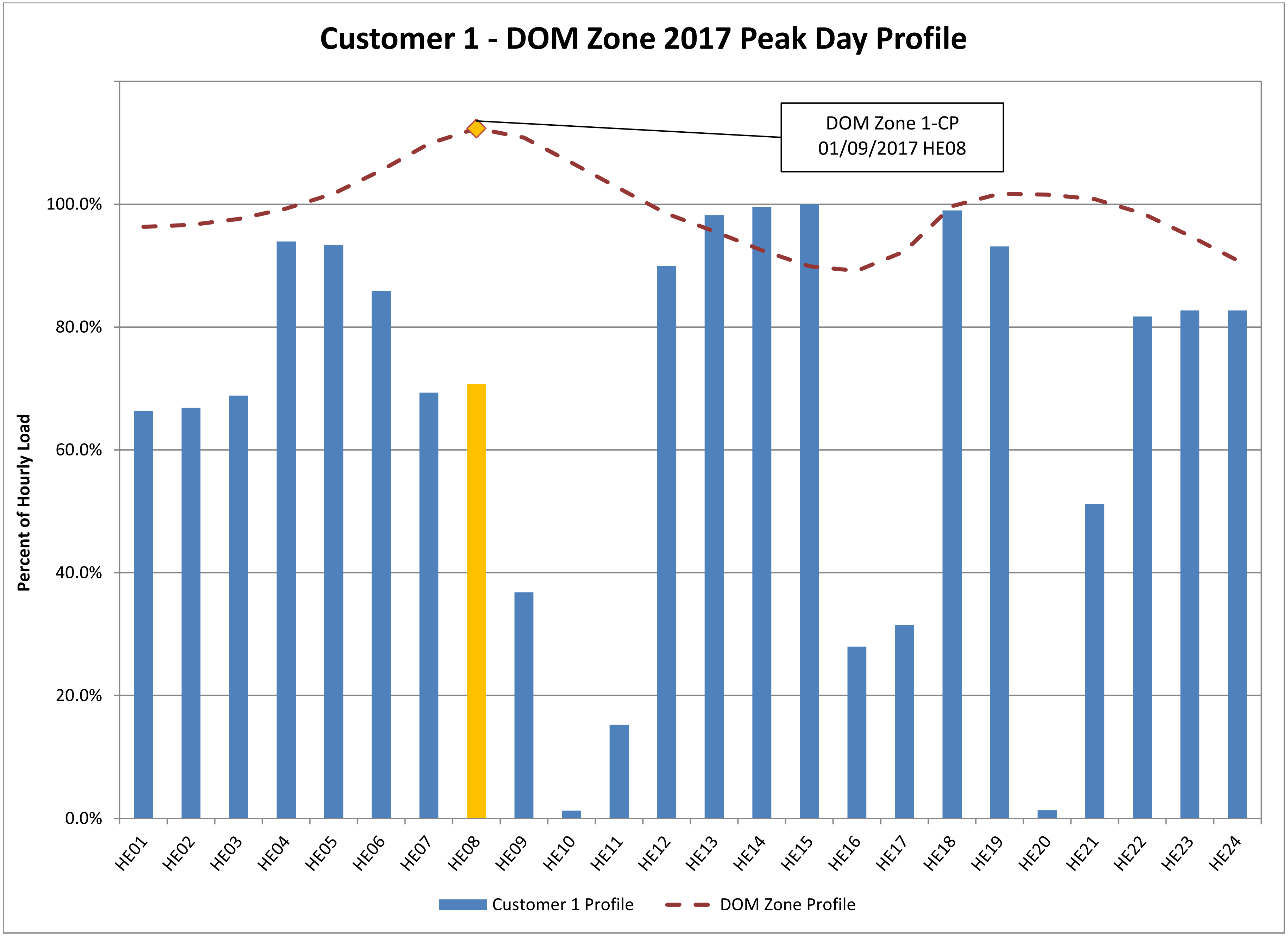
HE23
HE24
Customer 1 Profile
DOM Zone Profile


Customer 1 - DOM Zone 2017 Peak Day Profile
DOM Zone 1-CP
01/09/2017 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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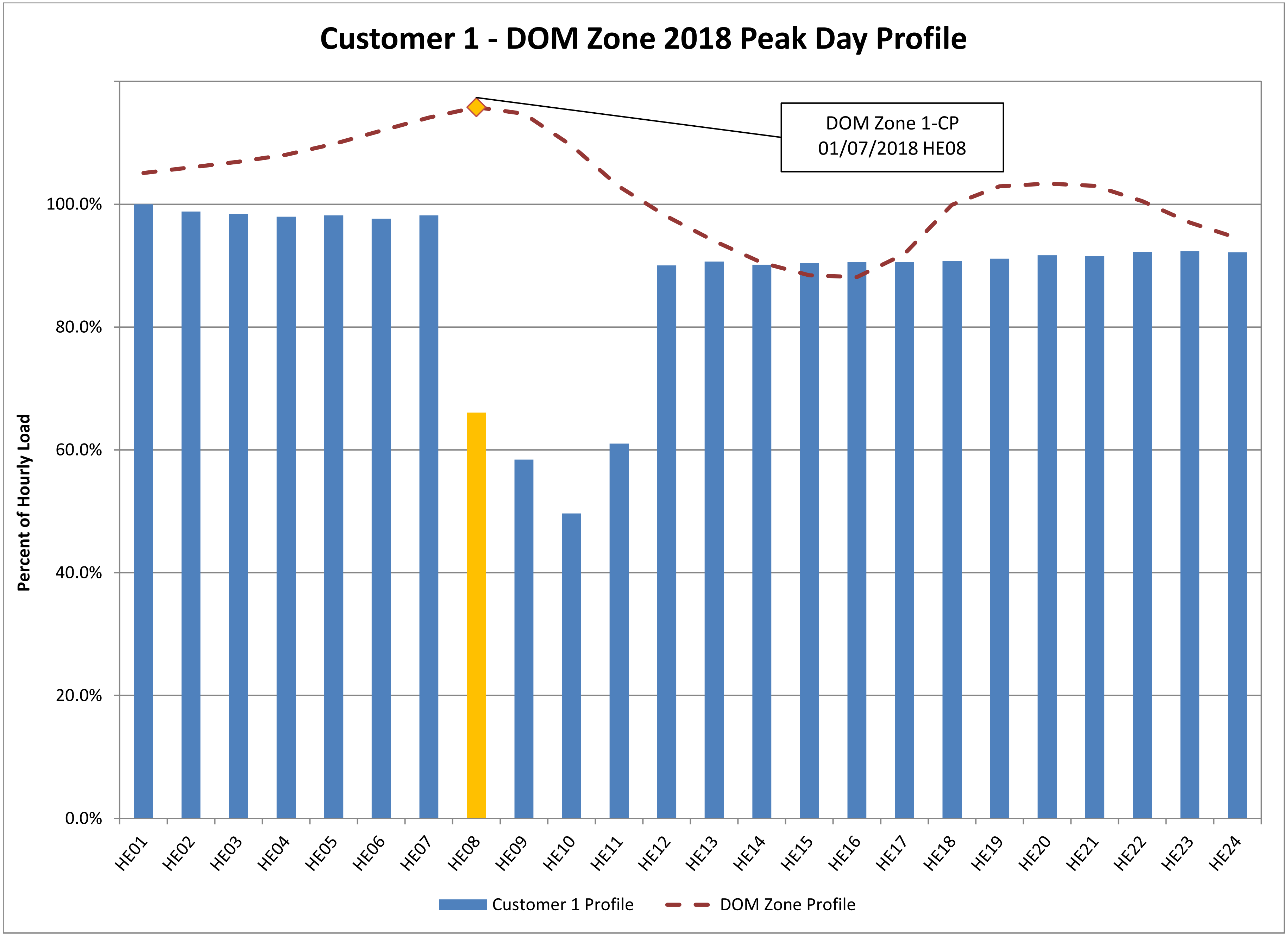
Customer 1 Profile
DOM Zone Profile


Customer 1 - DOM Zone 2018 Peak Day Profile
DOM Zone 1-CP
01/07/2018 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
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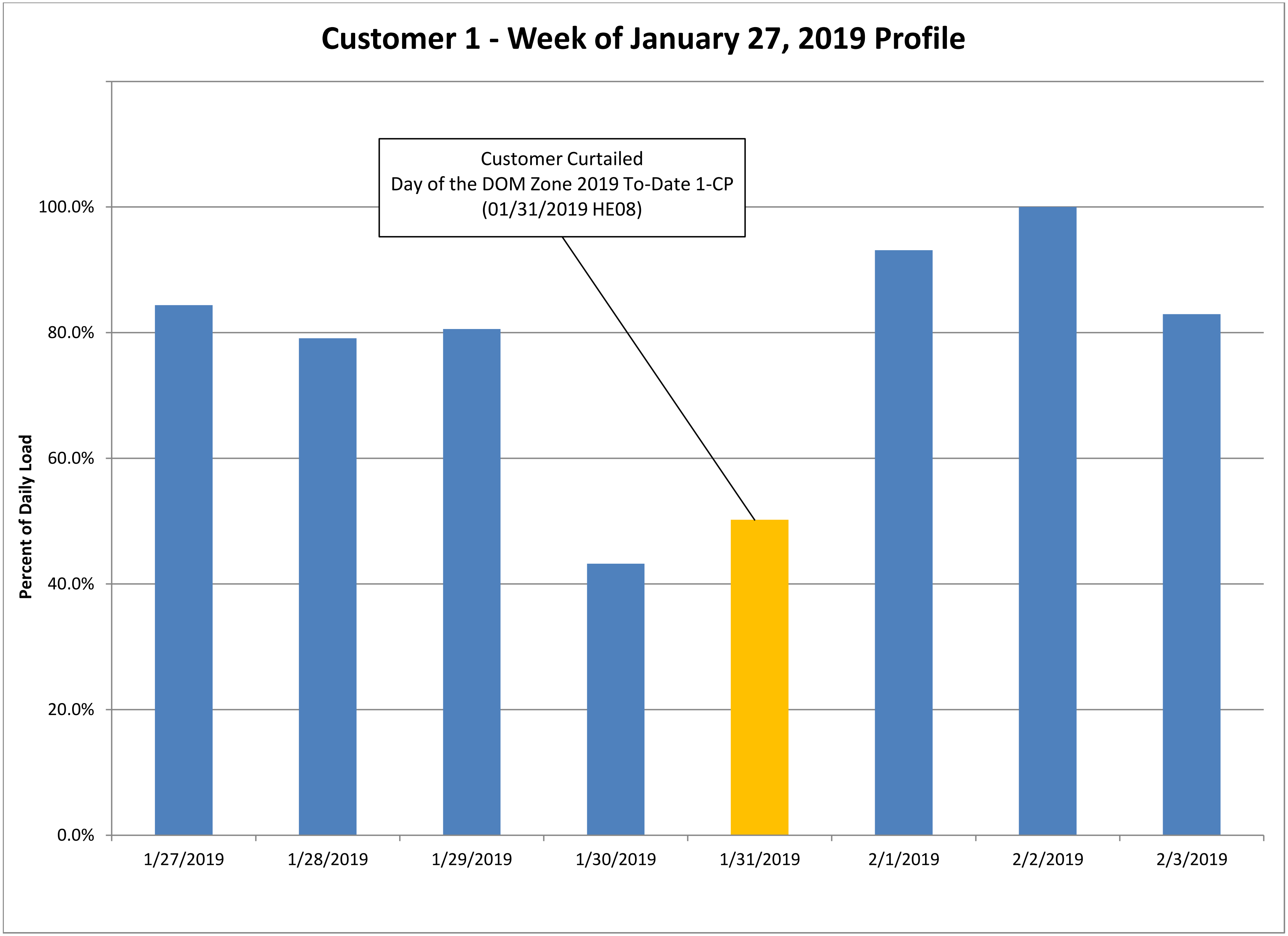
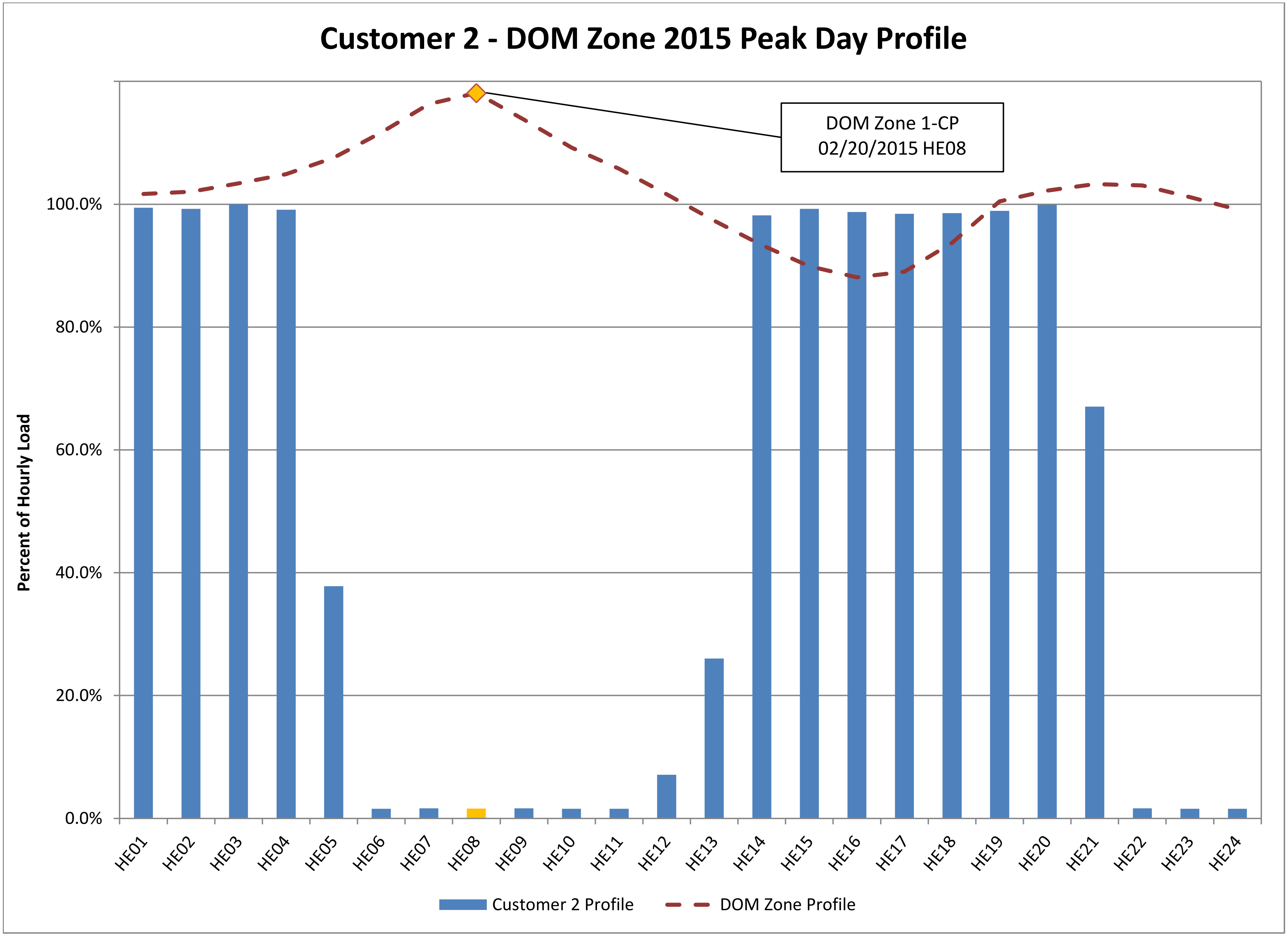
Customer 1 Profile
DOM Zone Profile


Customer 1 - Week of January 27, 2019 Profile
Customer Curtailed
Day of the DOM Zone 2019 To-Date 1-CP
(01/31/2019 HE08)
Percent of Daily Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
1/27/2019
1/28/2019
1/29/2019
1/30/2019
1/31/2019
2/1/2019
2/2/2019
2/3/2019


Customer 2 - DOM Zone 2015 Peak Day Profile
DOM Zone 1-CP
02/20/2015 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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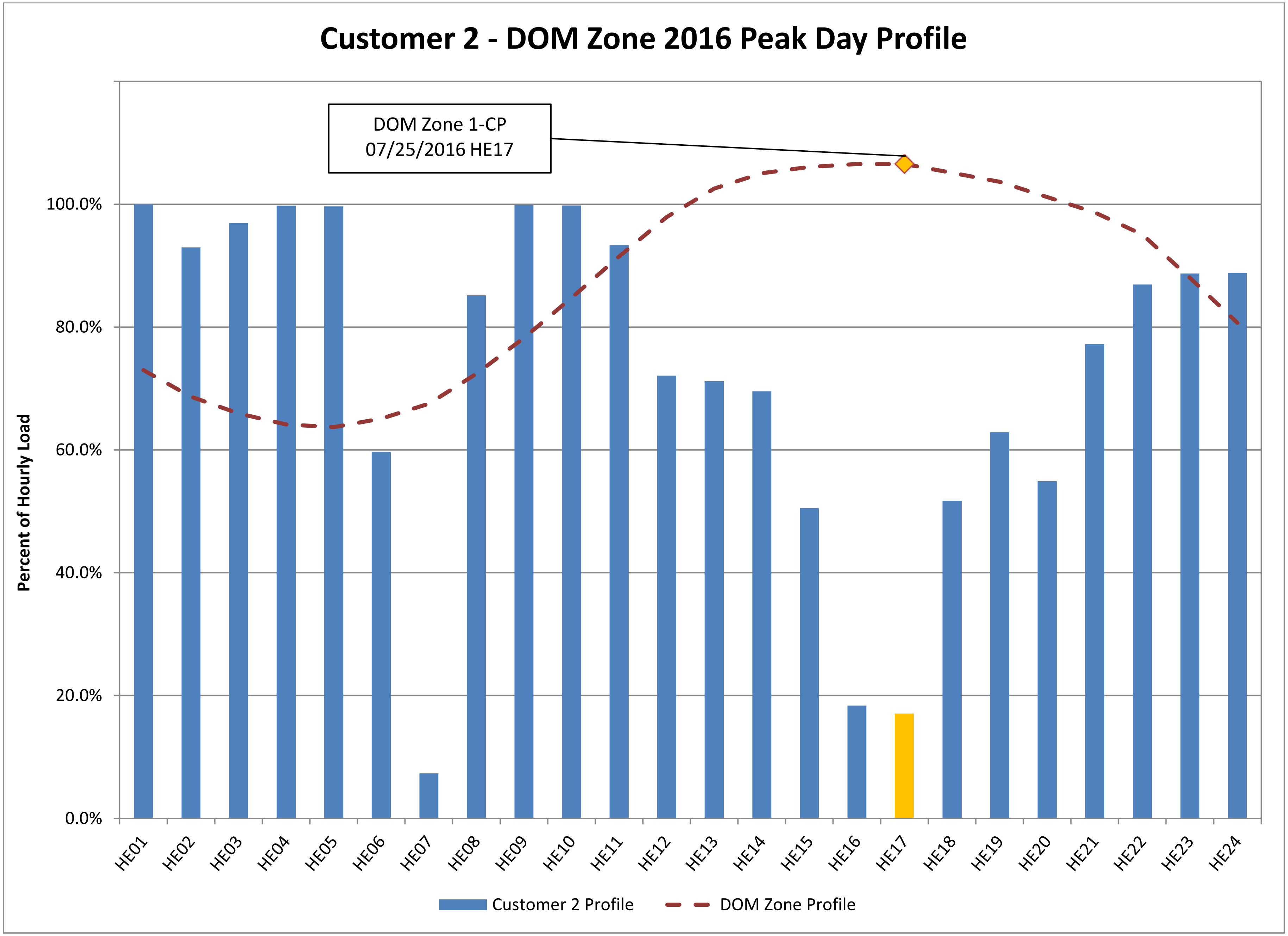
Customer 2 Profile
DOM Zone Profile


Customer 2 - DOM Zone 2016 Peak Day Profile
DOM Zone 1-CP
07/25/2016 HE17
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
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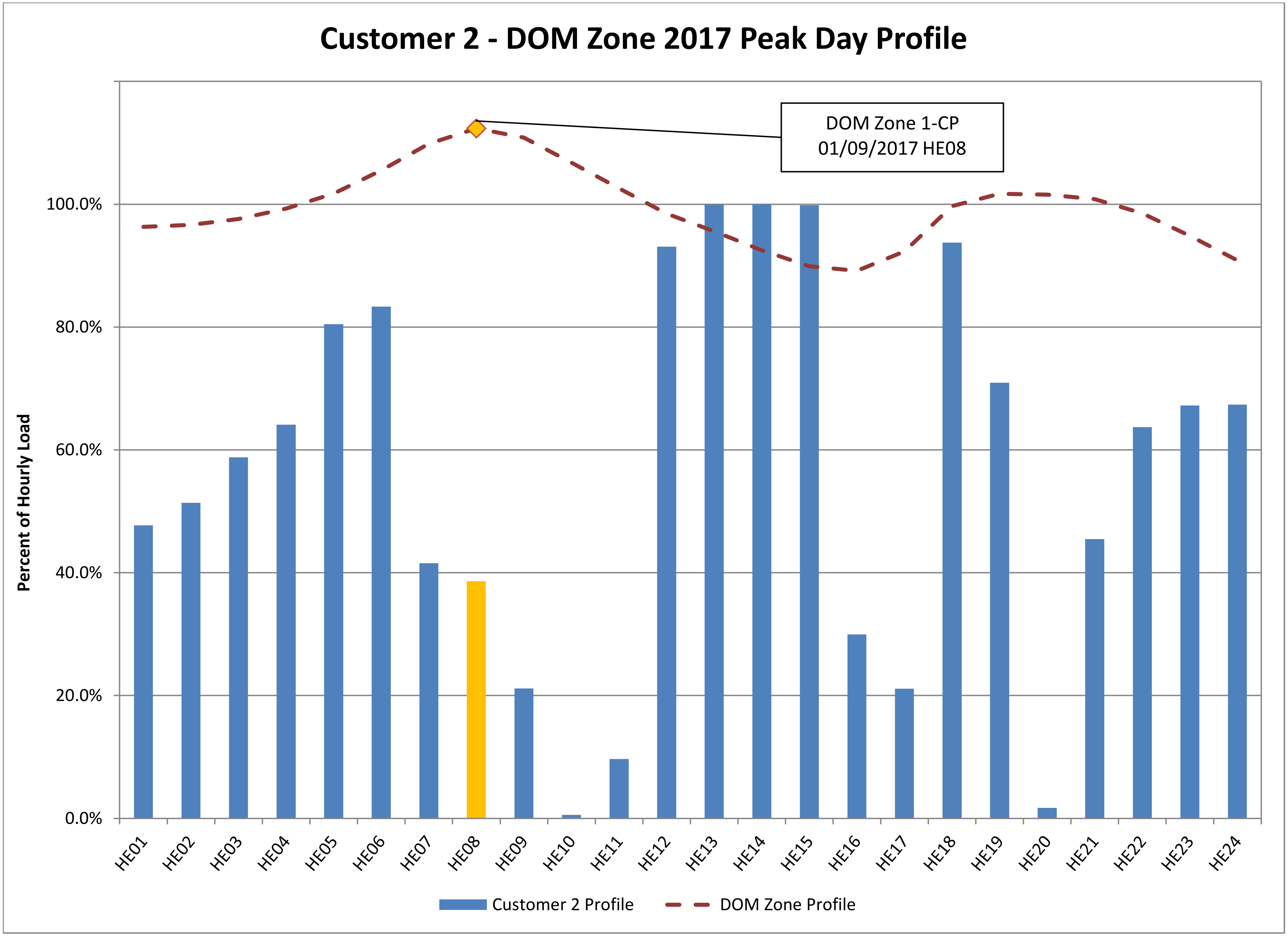
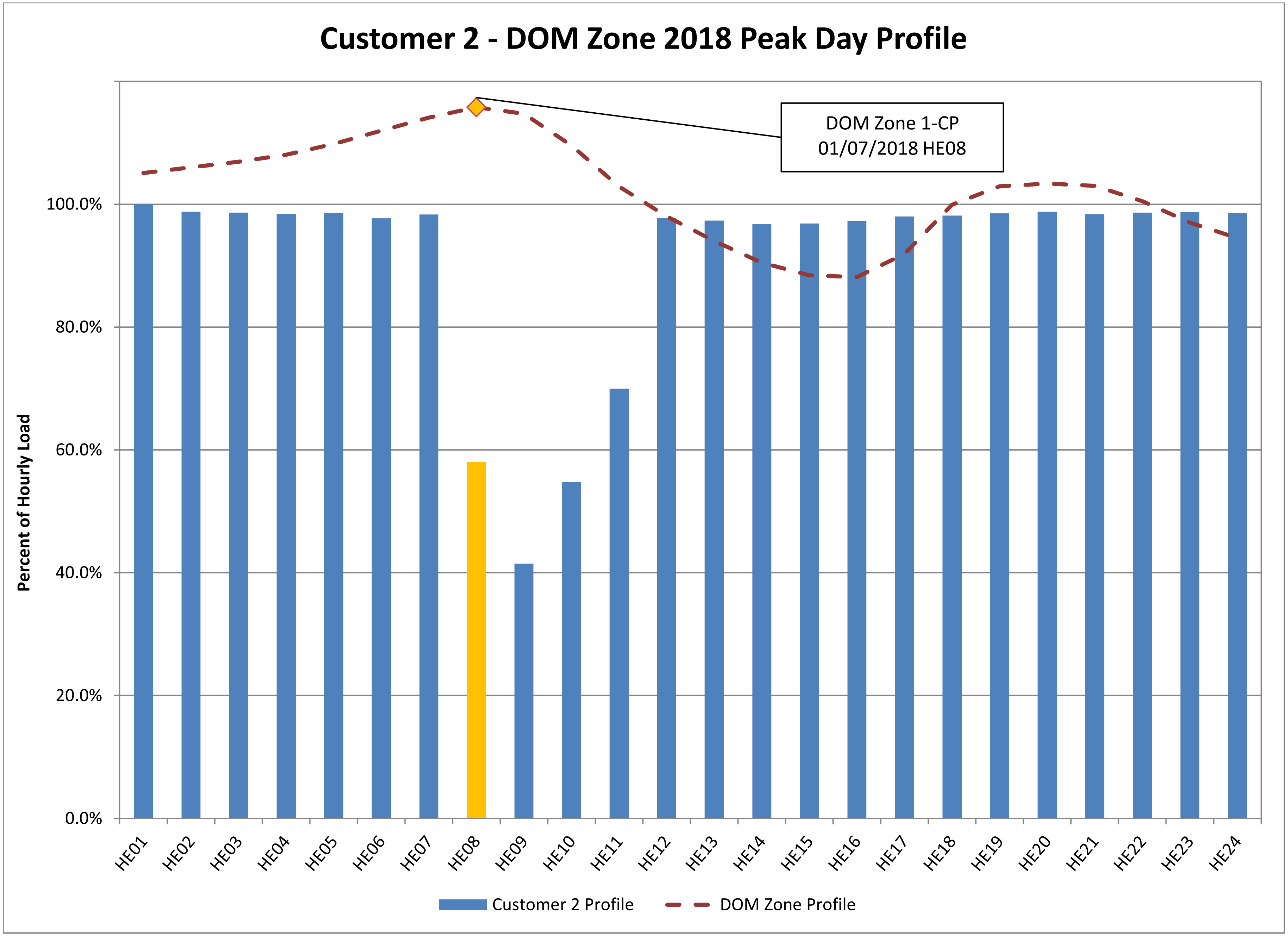
HE24
Customer 2 Profile
DOM Zone Profile

Exhibit 2(a) Docket No. ER19-1661




Customer 2 - DOM Zone 2018 Peak Day Profile
DOM Zone 1-CP
01/07/2018 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
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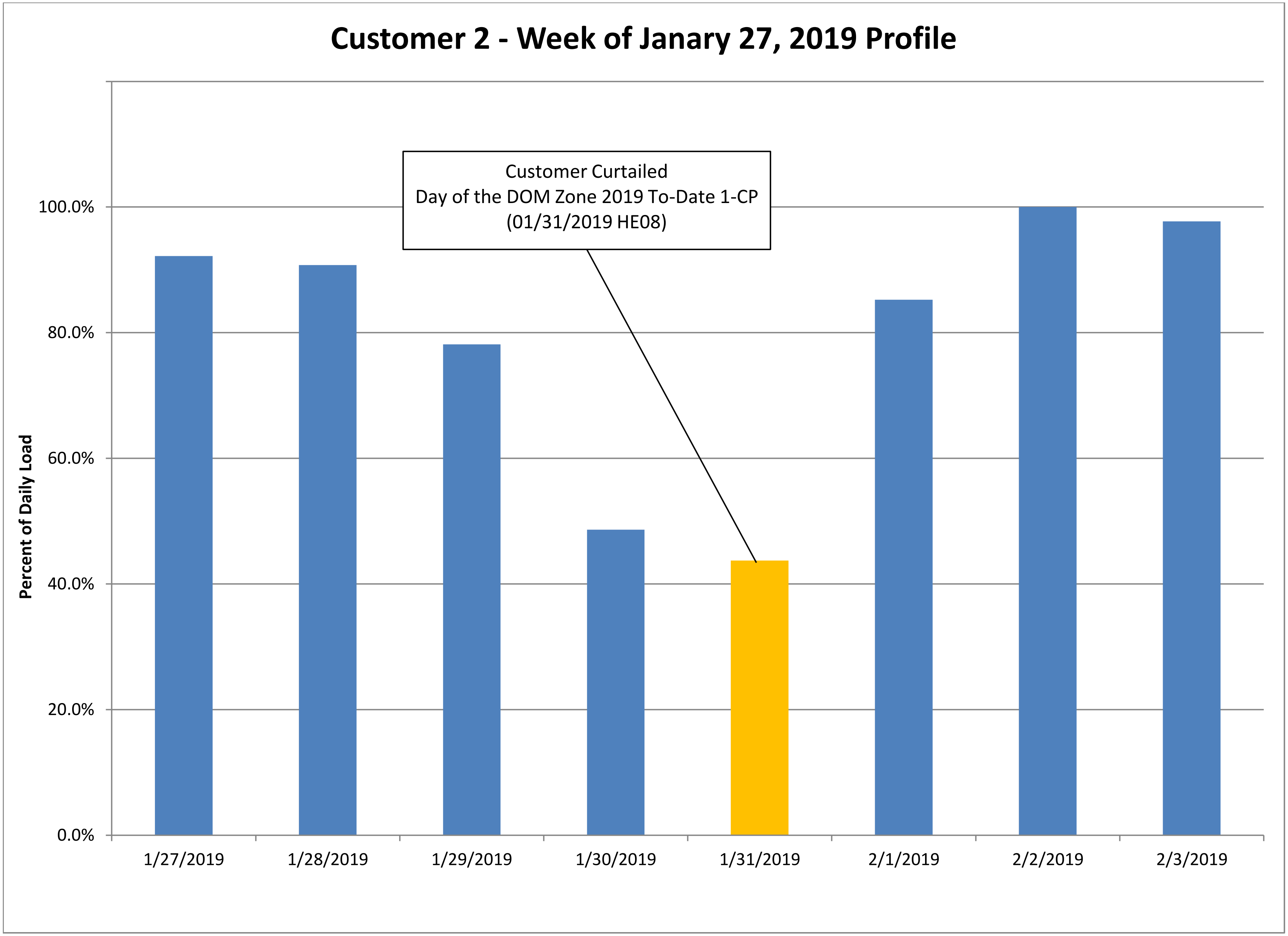
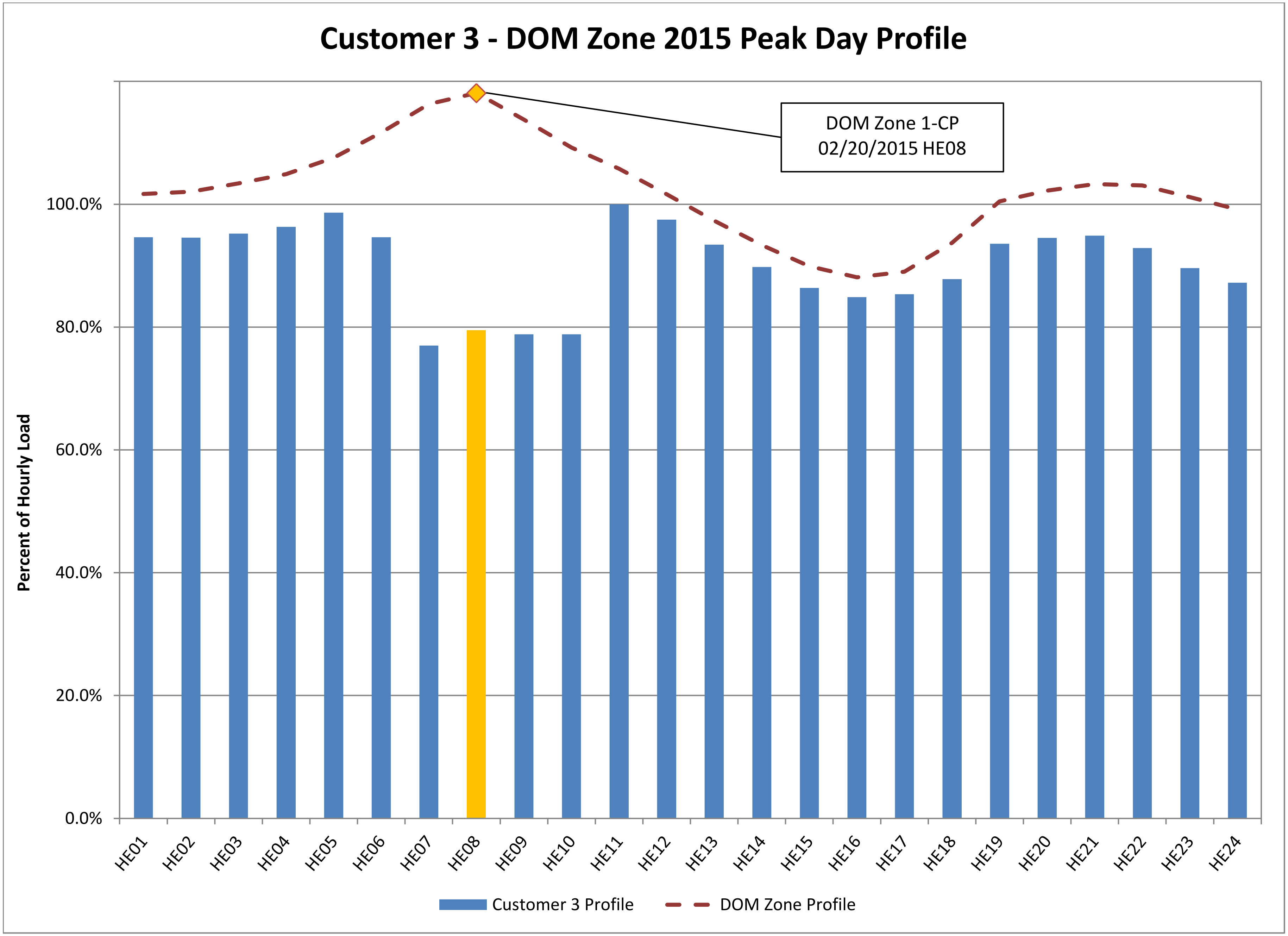
HE24
Customer 2 Profile
DOM Zone Profile

Exhibit 2(a) Docket No. ER19-1661




Customer 3 - DOM Zone 2015 Peak Day Profile
DOM Zone 1-CP
02/20/2015 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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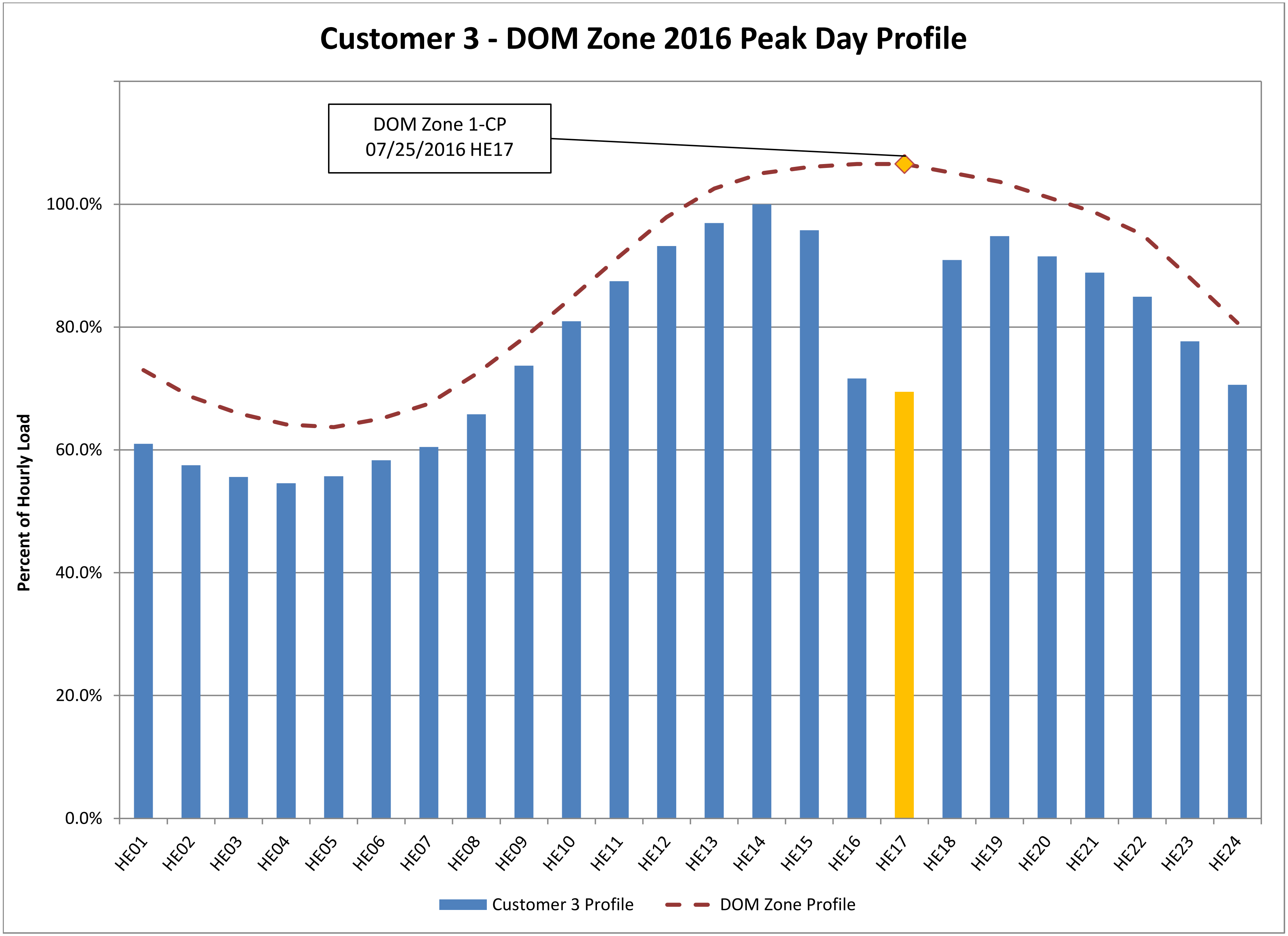
Customer 3 Profile
DOM Zone Profile


Customer 3 - DOM Zone 2016 Peak Day Profile
DOM Zone 1-CP
07/25/2016 HE17
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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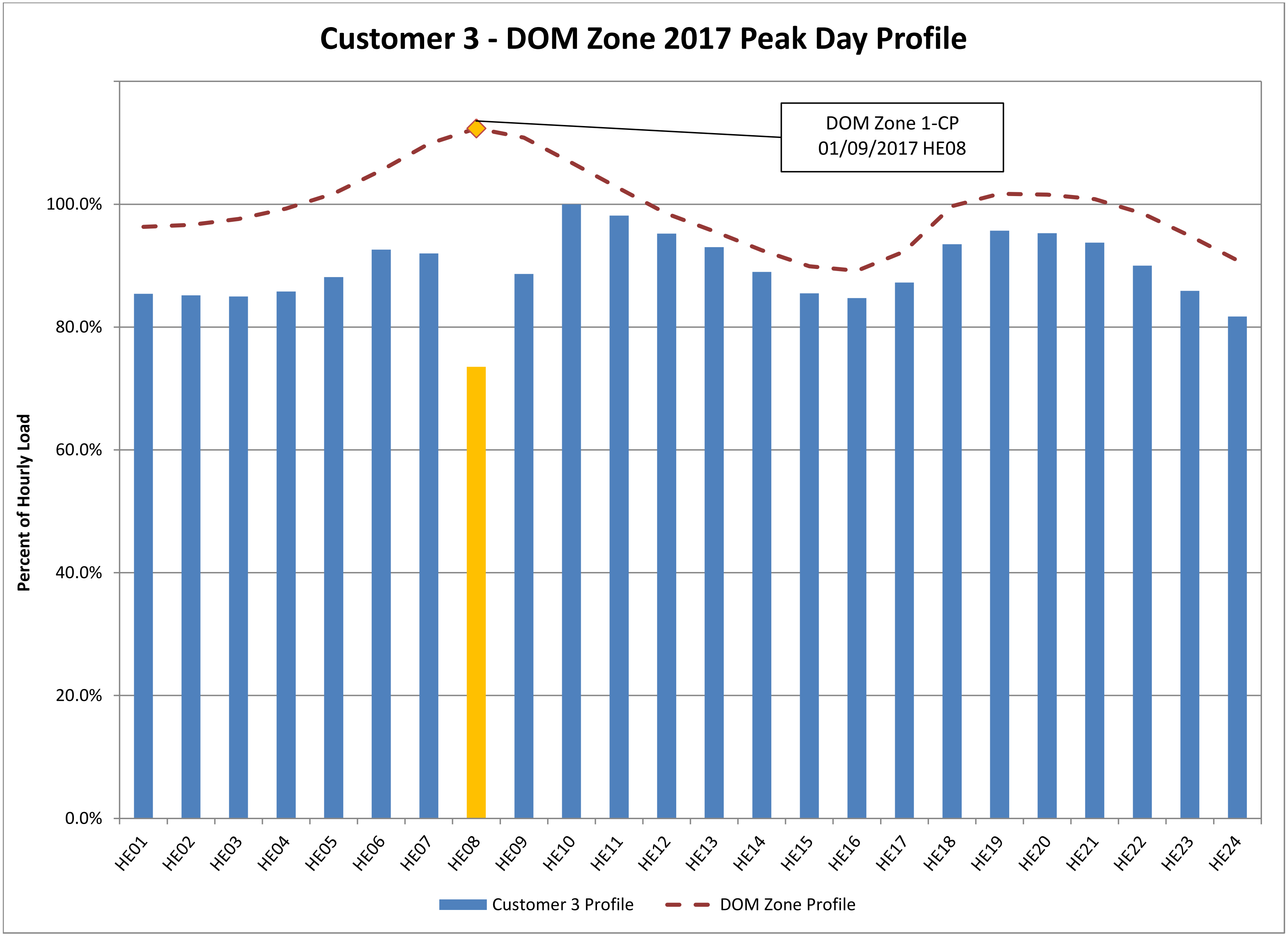
Customer 3 Profile
DOM Zone Profile


Customer 3 - DOM Zone 2017 Peak Day Profile
DOM Zone 1-CP
01/09/2017 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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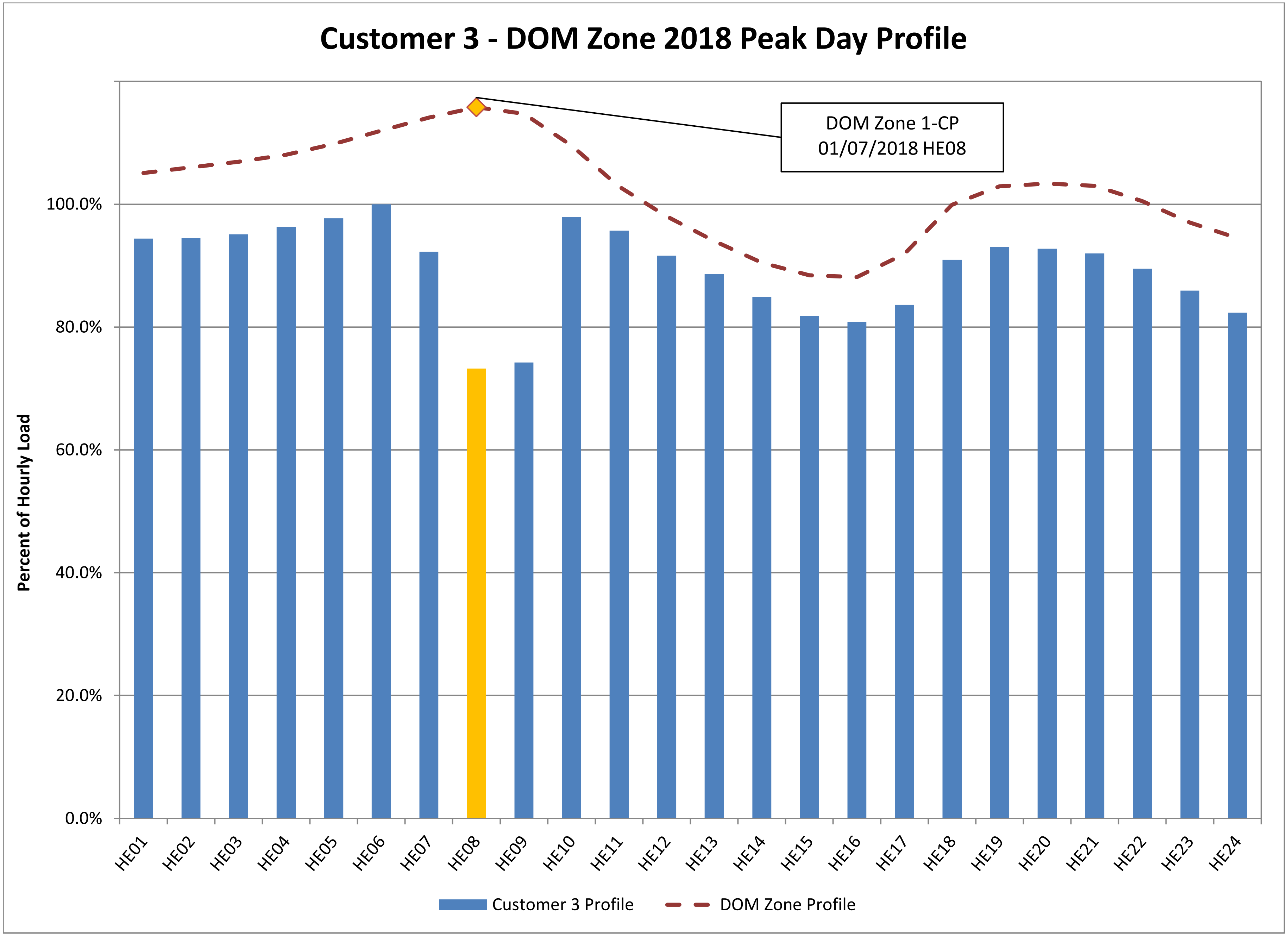
HE23
HE24
Customer 3 Profile
DOM Zone Profile


Customer 3 - DOM Zone 2018 Peak Day Profile
DOM Zone 1-CP
01/07/2018 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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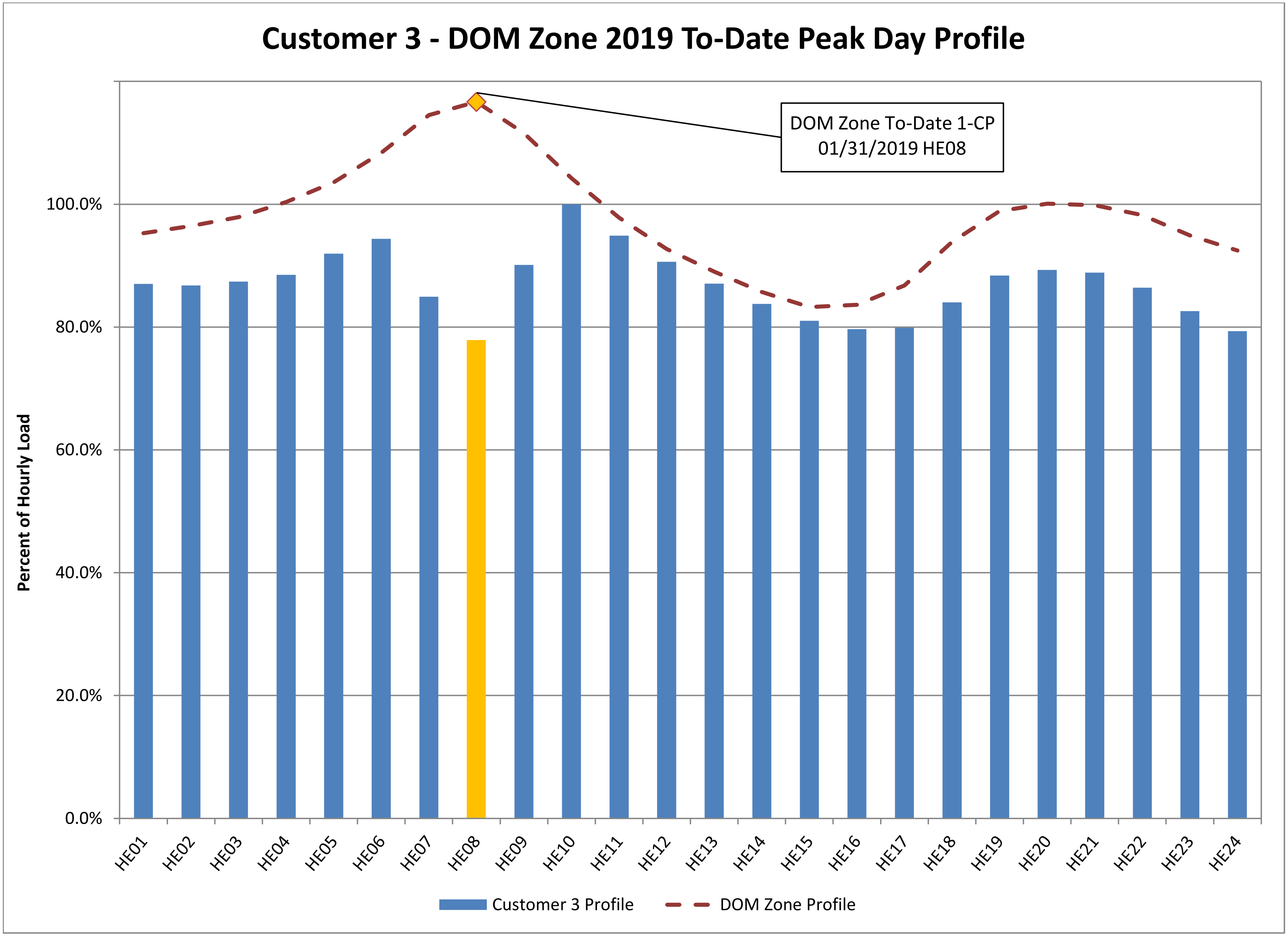
HE24
Customer 3 Profile
DOM Zone Profile


Customer 3 - DOM Zone 2019 To-Date Peak Day Profile
DOM Zone To-Date 1-CP
01/31/2019 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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HE04
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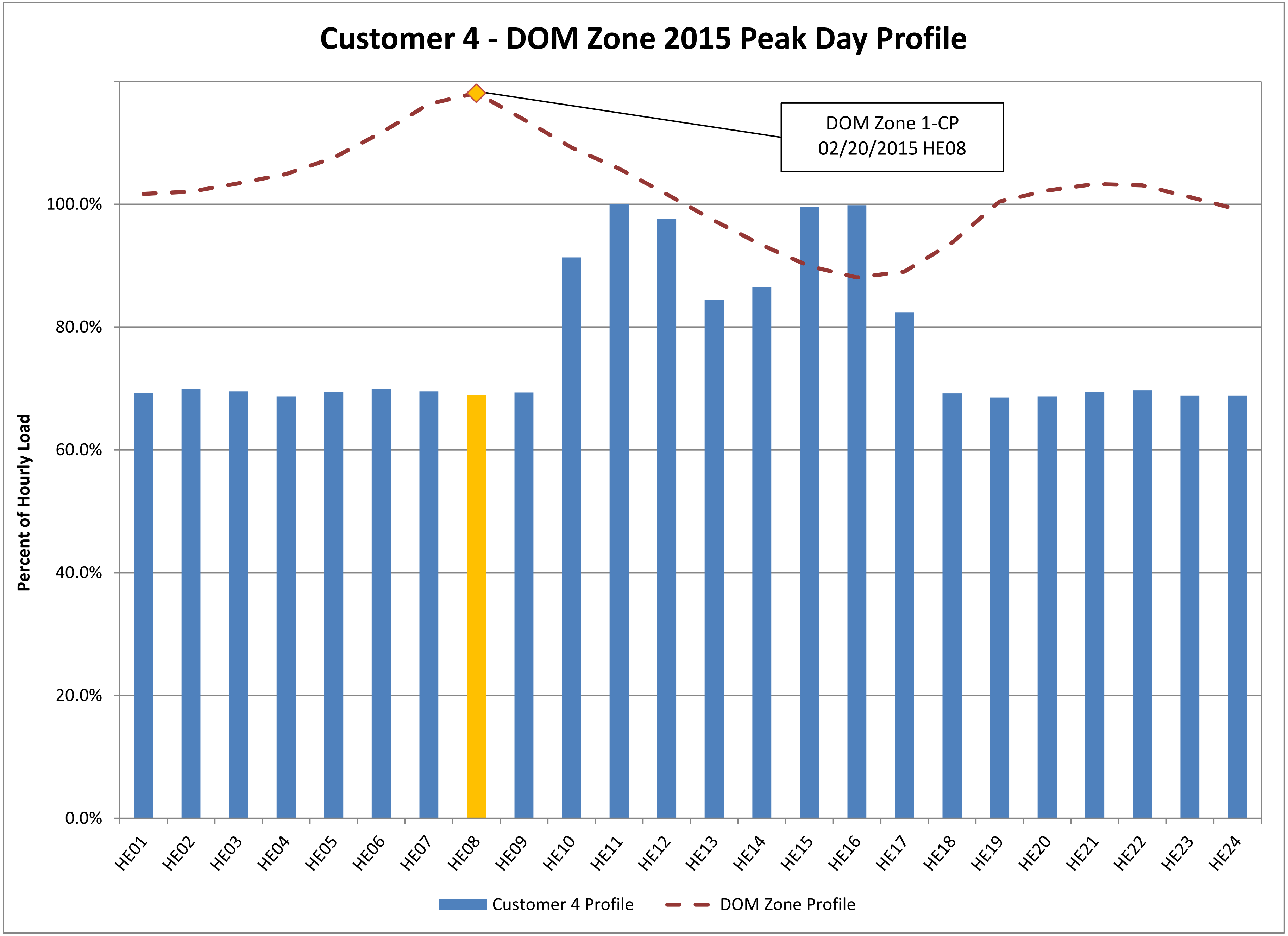
HE23
HE24
Customer 3 Profile
DOM Zone Profile


Customer 4 - DOM Zone 2015 Peak Day Profile
DOM Zone 1-CP
02/20/2015 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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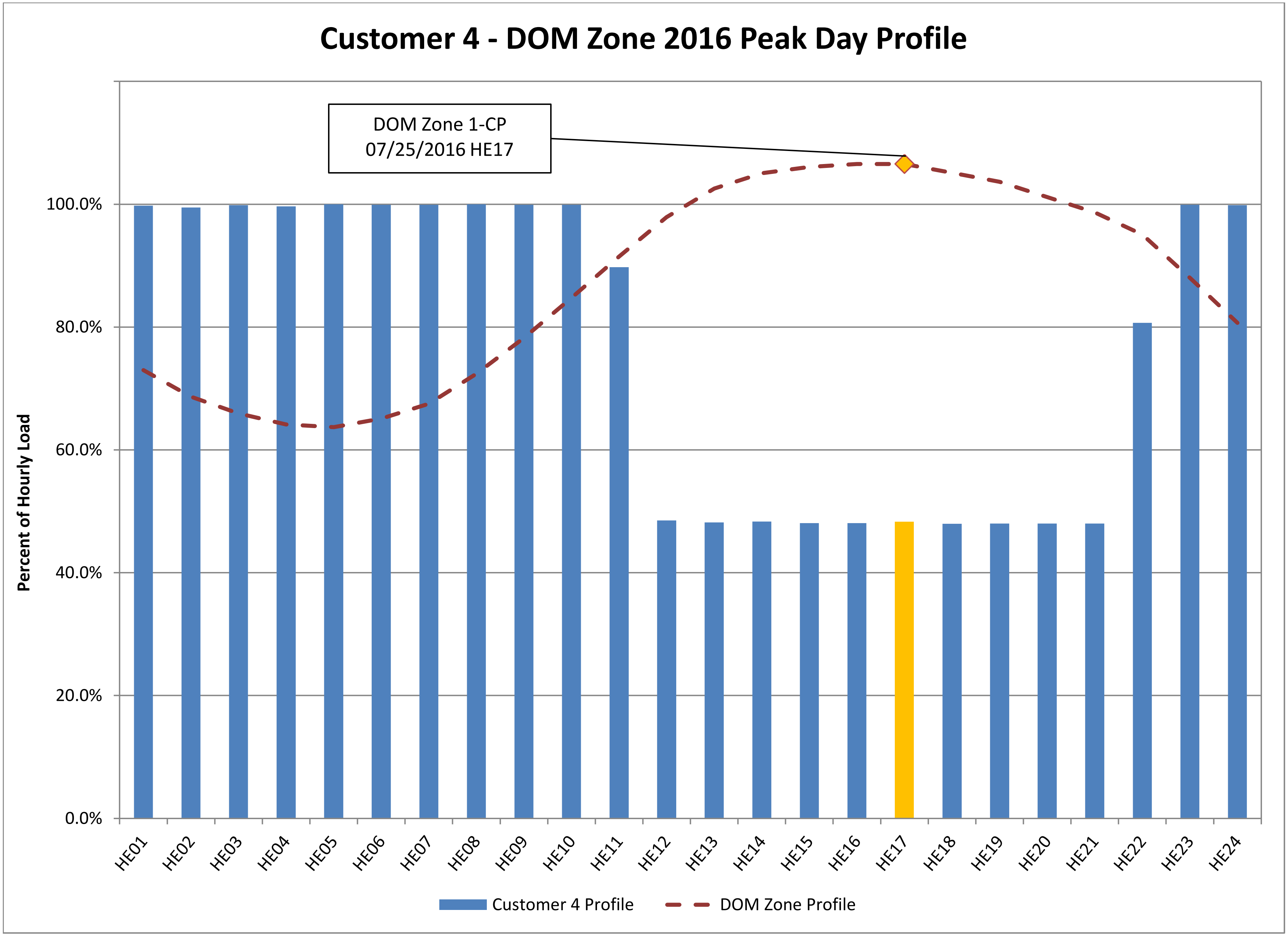
HE23
HE24
Customer 4 Profile
DOM Zone Profile


Customer 4 - DOM Zone 2016 Peak Day Profile
DOM Zone 1-CP
07/25/2016 HE17
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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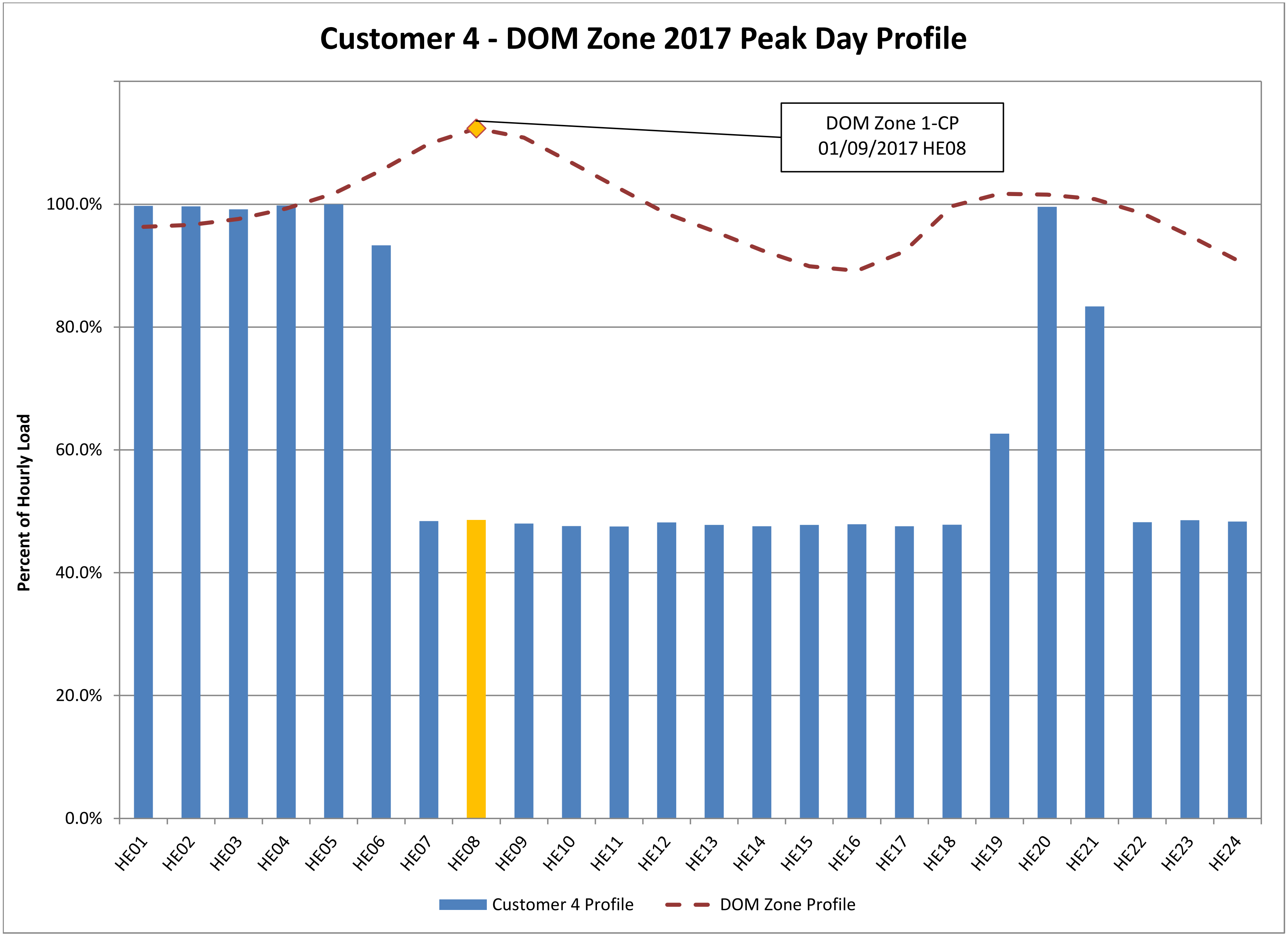
Customer 4 Profile
DOM Zone Profile


Customer 4 - DOM Zone 2017 Peak Day Profile
DOM Zone 1-CP
01/09/2017 HE08
Percent of Hourly Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
HE01
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HE24
Customer 4 Profile
DOM Zone Profile

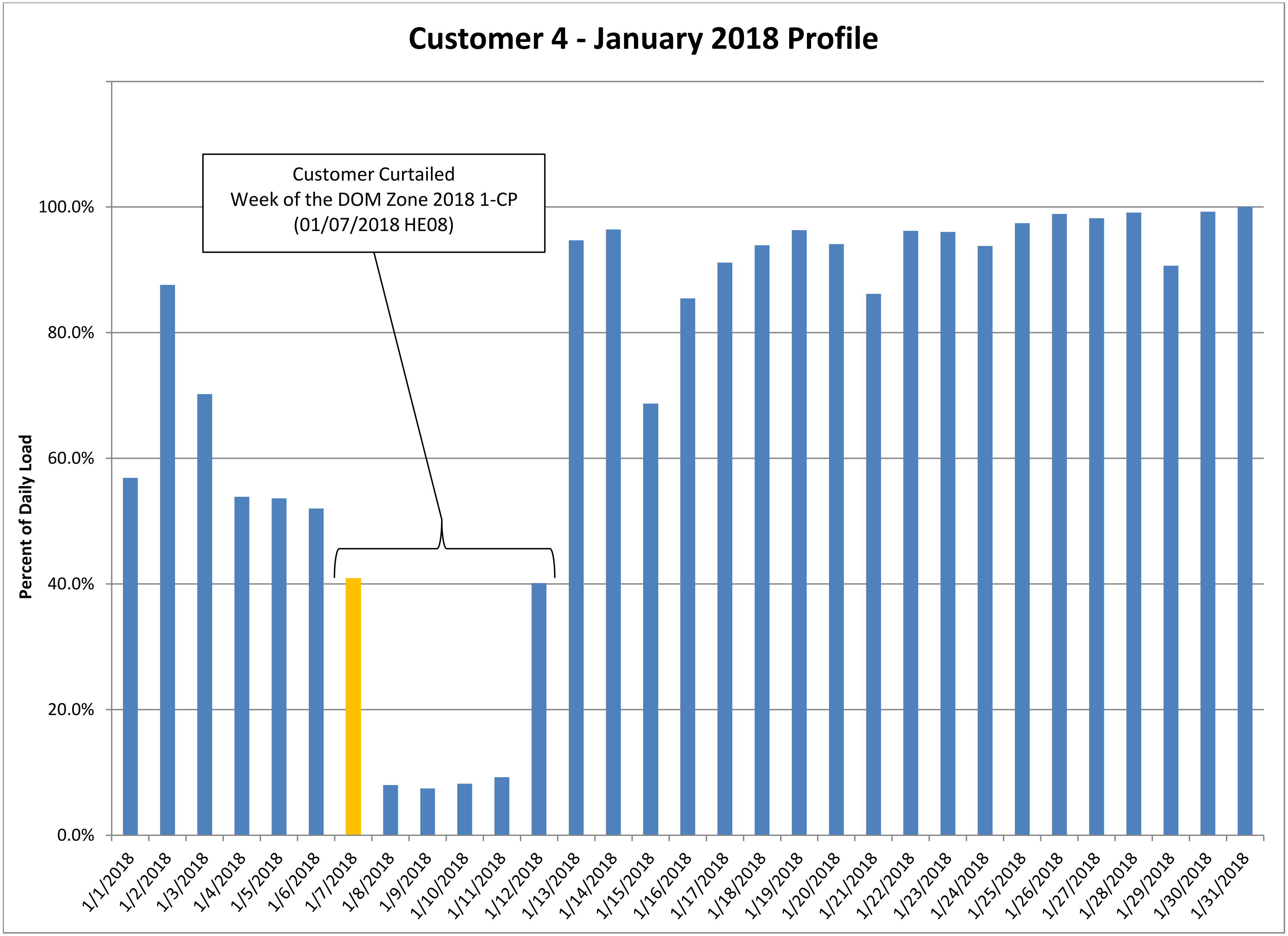
Customer 4 - January 2018 Profile
Customer Curtailed
Week of the DOM Zone 2018 1-CP
(01/07/2018 HE08)
Percent of Daily Load
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
1/1/2018
1/2/2018
1/3/2018
1/4/2018
1/5/2018
1/6/2018
1/7/2018
1/8/2018
1/9/2018
1/10/2018
1/11/2018
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Exhibit 2(a) Docket No. ER19-1661

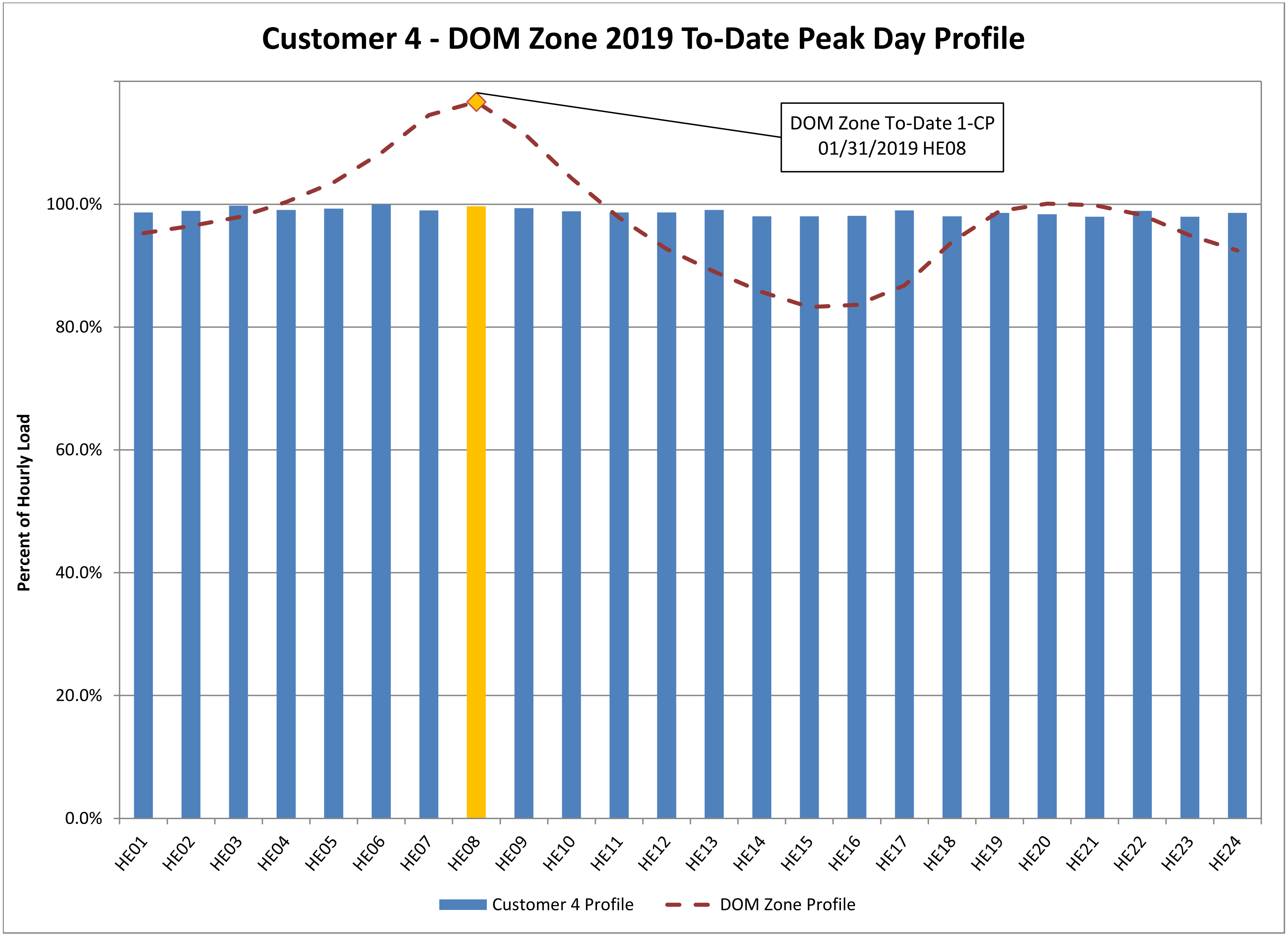


Exhibit 2(b)

Dominion Zone 1-CP Day		Dominion Zone Next Highest Peak Day		Percent Reduction in Demand 1-CP Day Compared to Next Highest Peak Day			
Date	Hour	Date	Hour	Customer 1	Customer 2	Customer 3	Customer 4
02/20/2015	HE08	01/08/2015	HE08	-93.9%	-94.5%	11.8%	-17.8%
07/25/2016	HE17	08/13/2016	HE17	-82.2%	-76.5%	-24.0%	-52.6%
01/09/2017	HE08	07/14/2017	HE16	6.2%	15.7%	-20.4%	-65.0%
01/07/2018	HE08	01/03/2018	HE08	-6.7%	-38.1%	-2.5%	-52.3%
01/31/2019*	HE08	01/22/2019*	HE08	-5.6%	-27.4%	7.3%	3.0%

* 2019 year to-date

Exhibit 2(c)

Exhibit 2(c) **Docket No. ER19-1661**

Customer 1																			
Percent Reduction in Demand 1-CP Hour Compared to NCP Hour				Percent Reduction in Demand Second Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Third Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Fourth Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Fifth Highest Peak Hour Compared to NCP Hour			
Date	Hour	Description	Customer 1	Date	Hour	Description	Customer 1	Date	Hour	Description	Customer 1	Date	Hour	Description	Customer 1	Date	Hour	Description	Customer 1
01/09/2017	HE08	DOM Zone 1-CP Hour	-29.2%	01/10/2017	HE08	DOM Zone Second Highest Peak Hour	-48.9%	03/15/2017	HE08	DOM Zone Third Highest Peak Hour	-2.0%	02/10/2017	HE08	DOM Zone Fourth Highest Peak Hour	-14.4%	03/16/2017	HE08	DOM Zone Fift Highest Peak Hour	-99.3%
	HE15	Customer's NCP Hour			HE16	Customer's NCP Hour			HE10	Customer's NCP Hour			HE01	Customer's NCP Hour			HE15	Customer's NCP Hour	
01/07/2018	HE08	DOM Zone 1-CP Hour	-33.9%	01/08/2018	HE08	DOM Zone Second Highest Peak Hour	-5.4%	01/18/2018	HE08	DOM Zone Third Highest Peak Hour	-32.5%	01/15/2018	HE08	DOM Zone Fourth Highest Peak Hour	-59.3%	01/17/2018	HE19	DOM Zone Fift Highest Peak Hour	-1.7%
	HE01	Customer's NCP Hour			HE14	Customer's NCP Hour			HE06	Customer's NCP Hour			HE01	Customer's NCP Hour			HE01	Customer's NCP Hour	
01/31/2019	HE08*	DOM Zone 1-CP Hour	-8.4%	02/01/2019	HE08	DOM Zone Second Highest Peak Hour	-37.8%	02/02/2019	HE08	DOM Zone Third Highest Peak Hour	-0.6%	03/06/2019	HE07	DOM Zone Fourth Highest Peak Hour	-14.5%	03/07/2019	HE07	DOM Zone Fift Highest Peak Hour	-4.6%
	HE24	Customer's NCP Hour			HE18	Customer's NCP Hour			HE01	Customer's NCP Hour			HE03	Customer's NCP Hour			HE03	Customer's NCP Hour	

Customer 2																			
Percent Reduction in Demand 1-CP Hour Compared to NCP Hour				Percent Reduction in Demand Second Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Third Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Fourth Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Fifth Highest Peak Hour Compared to NCP Hour			
Date	Hour	Description	Customer 2	Date	Hour	Description	Customer 2	Date	Hour	Description	Customer 2	Date	Hour	Description	Customer 2	Date	Hour	Description	Customer 2
01/09/2017	HE08	DOM Zone 1-CP Hour	-61.4%	01/10/2017	HE08	DOM Zone Second Highest Peak Hour	-2.4%	03/15/2017	HE08	DOM Zone Third Highest Peak Hour	-0.2%	02/10/2017	HE08	DOM Zone Fourth Highest Peak Hour	-42.8%	03/16/2017	HE08	DOM Zone Fift Highest Peak Hour	-1.2%
	HE14	Customer's NCP Hour			HE10	Customer's NCP Hour			HE10	Customer's NCP Hour			HE06	Customer's NCP Hour			HE12	Customer's NCP Hour	
01/07/2018	HE08	DOM Zone 1-CP Hour	-42.0%	01/08/2018	HE08	DOM Zone Second Highest Peak Hour	-31.2%	01/18/2018	HE08	DOM Zone Third Highest Peak Hour	-38.4%	01/15/2018	HE08	DOM Zone Fourth Highest Peak Hour	-31.9%	01/17/2018	HE19	DOM Zone Fift Highest Peak Hour	0.0%
	HE01	Customer's NCP Hour			HE01	Customer's NCP Hour			HE03	Customer's NCP Hour			HE03	Customer's NCP Hour			HE19	Customer's NCP Hour	
01/31/2019	HE08*	DOM Zone 1-CP Hour	-32.2%	02/01/2019	HE08	DOM Zone Second Highest Peak Hour	-60.5%	02/02/2019	HE08	DOM Zone Third Highest Peak Hour	-0.2%	03/06/2019	HE07	DOM Zone Fourth Highest Peak Hour	-11.8%	03/07/2019	HE07	DOM Zone Fift Highest Peak Hour	-7.4%
	HE24	Customer's NCP Hour			HE22	Customer's NCP Hour			HE07	Customer's NCP Hour			HE16	Customer's NCP Hour			HE05	Customer's NCP Hour	

Customer 3																			
Percent Reduction in Demand 1-CP Hour Compared to NCP Hour				Percent Reduction in Demand Second Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Third Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Fourth Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Fifth Highest Peak Hour Compared to NCP Hour			
Date	Hour	Description	Customer 3	Date	Hour	Description	Customer 3	Date	Hour	Description	Customer 3	Date	Hour	Description	Customer 3	Date	Hour	Description	Customer 3
01/09/2017	HE08	DOM Zone 1-CP Hour	-26.5%	01/10/2017	HE08	DOM Zone Second Highest Peak Hour	0.0%	03/15/2017	HE08	DOM Zone Third Highest Peak Hour	-2.0%	02/10/2017	HE08	DOM Zone Fourth Highest Peak Hour	-0.7%	03/16/2017	HE08	DOM Zone Fift Highest Peak Hour	0.0%
	HE10	Customer's NCP Hour			HE08	Customer's NCP Hour			HE09	Customer's NCP Hour			HE09	Customer's NCP Hour			HE08	Customer's NCP Hour	
01/07/2018	HE08	DOM Zone 1-CP Hour	-26.7%	01/08/2018	HE08	DOM Zone Second Highest Peak Hour	0.0%	01/18/2018	HE08	DOM Zone Third Highest Peak Hour	0.0%	01/15/2018	HE08	DOM Zone Fourth Highest Peak Hour	0.0%	01/17/2018	HE19	DOM Zone Fift Highest Peak Hour	0.0%
	HE06	Customer's NCP Hour			HE08	Customer's NCP Hour			HE08	Customer's NCP Hour			HE08	Customer's NCP Hour			HE19	Customer's NCP Hour	
01/31/2019	HE08*	DOM Zone 1-CP Hour	-22.1%	02/01/2019	HE08	DOM Zone Second Highest Peak Hour	-3.1%	02/02/2019	HE08	DOM Zone Third Highest Peak Hour	0.0%	03/06/2019	HE07	DOM Zone Fourth Highest Peak Hour	0.0%	03/07/2019	HE07	DOM Zone Fift Highest Peak Hour	-0.7%
	HE10	Customer's NCP Hour			HE09	Customer's NCP Hour			HE08	Customer's NCP Hour			HE07	Customer's NCP Hour			HE08	Customer's NCP Hour	

Customer 4																			
Percent Reduction in Demand 1-CP Hour Compared to NCP Hour				Percent Reduction in Demand Second Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Third Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Fourth Highest Peak Hour Compared to NCP Hour				Percent Reduction in Demand Fifth Highest Peak Hour Compared to NCP Hour			
Date	Hour	Description	Customer 4	Date	Hour	Description	Customer 4	Date	Hour	Description	Customer 4	Date	Hour	Description	Customer 4	Date	Hour	Description	Customer 4
01/09/2017	HE08	DOM Zone 1-CP Hour	-51.5%	01/10/2017	HE08	DOM Zone Second Highest Peak Hour	-52.0%	03/15/2017	HE08	DOM Zone Third Highest Peak Hour	-0.5%	02/10/2017	HE08	DOM Zone Fourth Highest Peak Hour	-0.6%	03/16/2017	HE08	DOM Zone Fift Highest Peak Hour	-12.0%
	HE05	Customer's NCP Hour			HE20	Customer's NCP Hour			HE09	Customer's NCP Hour			HE06	Customer's NCP Hour			HE17	Customer's NCP Hour	
01/07/2018	HE08	DOM Zone 1-CP Hour	-11.4%	01/08/2018	HE08	DOM Zone Second Highest Peak Hour	-37.4%	01/18/2018	HE08	DOM Zone Third Highest Peak Hour	-6.1%	01/15/2018	HE08	DOM Zone Fourth Highest Peak Hour	-32.9%	01/17/2018	HE19	DOM Zone Fift Highest Peak Hour	-0.6%
	HE04	Customer's NCP Hour			HE01	Customer's NCP Hour			HE24	Customer's NCP Hour			HE23	Customer's NCP Hour			HE21	Customer's NCP Hour	
01/31/2019	HE08*	DOM Zone 1-CP Hour	-0.4%	02/01/2019	HE08	DOM Zone Second Highest Peak Hour	-1.1%	02/02/2019	HE08	DOM Zone Third Highest Peak Hour	-0.8%	03/06/2019	HE07	DOM Zone Fourth Highest Peak Hour	-0.2%	03/07/2019	HE07	DOM Zone Fift Highest Peak Hour	-0.1%
	HE06	Customer's NCP Hour			HE03	Customer's NCP Hour			HE01	Customer's NCP Hour			HE05	Customer's NCP Hour			HE23	Customer's NCP Hour	

* 2019 year to-date

Exhibit 3(b)(1)

Demand response – the ability of retail consumers to respond to wholesale electricity prices – is integrated into PJM Interconnection's wholesale electricity markets, providing equivalent treatment for generation and demand resources. Retail customers have the opportunity to participate in PJM's energy, capacity and other markets and receive payments for the demand reductions they make.

PJM is working to broaden the opportunities for electricity consumers to respond to wholesale prices and grid conditions.

Consumers have the opportunity to manage their electricity use in response to conditions in the wholesale market. They can reduce their electricity consumption when wholesale prices are high or the reliability of the grid is threatened, receiving payments for the reductions they make. Common examples of reductions are turning up the temperature on the thermostat to reduce air conditioning or slowing down or stopping production at an industrial facility temporarily.

Some industrial customers with backup generation and appropriate environmental permits might use their generators to meet a portion of their power needs during peak periods, enabling them to draw less from the system and reduce demand on the grid.

Even though wholesale electricity prices fluctuate hourly, retail consumers generally pay electricity rates that are based on average electricity costs. This means that they don't see the changes in wholesale prices and don't have the opportunity to react to them. Without clear price signals, consumers have no incentive to reduce their usage when wholesale prices are high.

Giving consumers the ability to "see" wholesale prices and react when prices are high can help minimize the impact of price spikes, reduce the need for expensive peaking generating capacity and help hold down energy prices overall.

The choice to participate in demand response is voluntary. But, participants must meet certain requirements in order to qualify for payments for reducing their demand for electricity. Demand response does not include reductions in electricity use that follow normal operating patterns or behavior.

The following summarizes how demand response works in PJM.

Qualified PJM market participants who act as agents, called Curtailment Service Providers, work with retail customers who wish to participate in demand response. CSPs aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM. The allocation of the PJM payment between the CSP and the retail customer is a matter of private agreement between them.

A CSP can help a customer identify opportunities and determine the needed equipment and systems to benefit financially from demand response participation.

When locational marginal prices are high in PJM's Energy Market, economic demand response provides an opportunity to reduce electricity consumption and receive a payment. Participants have the choice of a day-ahead option or a real-time option.

In the day-ahead option, a CSP's customers can offer – in advance of real-time operations – to reduce the amount of electricity they will draw from the PJM system. If the offers are accepted, they will receive payments based on the day-ahead prices for the reductions. In the real-time option, a CSP helps customers reduce their usage voluntarily during times of high prices and receive payments based on real-time prices for those reductions.

Emergency load response compensates retail customers who reduce their usage during emergency conditions on the PJM system. The voluntary energy-only option compensates retail customers who choose to reduce their usage voluntarily during emergency conditions.

In PJM's Reliability Pricing Model capacity market, both demand-response resources and energy-efficiency resources have the opportunity to participate. They can receive payments for being ready to reduce their electricity demand or for implementing energy-efficiency measures.

The capacity market helps keep the lights on. It ensures that when electricity usage is high, there are enough resources available to meet the demand at all times. Those resources – generation as well as demand resources – enable electricity providers to have enough power to be drawn from when needed to meet the demand instantaneously.

Demand resources, through CSPs, can bid demand reductions into the market. Capacity is obtained three years in advance. For example, the capacity auction held in May 2017 will obtain capacity for the 2020/2021 delivery year.

The ability to call on demand reductions gives system operators greater flexibility in managing the grid during summer heat waves and other challenging conditions. There are two separate opportunities for demand response in the RPM capacity market, with differing requirements. This will be reduced to one option starting in 2020/21.

In the base product, customers commit to reducing their load at the direction of PJM during emergency conditions during the summer months. In the Capacity Performance product, the customer will need to be able to reduce load when directed during the entire year.

A total of nearly 9,770 megawatts of demand response are committed as capacity resources for the 2017/2018 delivery year.

PJM also enables demand resources to participate and submit bids for reductions in the Synchronized Reserve, Regulation and Day-Ahead Scheduling Reserves markets.

PJM's eLRS tool provides CSPs, as well as electric distribution companies and load-serving entities, with an online tool for processing the registration of demand resources and demand reduction activity and transactions in the PJM markets. eLRS is in the process of being replaced with a new tool called DR Hub.

PJM's goal is to see demand response fully integrated into the retail market. That will happen when a large number of retail electric customers, including homes and small businesses, have access to demand-response options. PJM is working with state commissions and other stakeholders to support that goal.

April 11, 2017

Exhibit 3(b)(2)

Load Management Performance Report

2018/2019

(mid Delivery Year update)

January 2019

PJM has made all efforts possible to accurately document all information in this report. However, PJM cannot warrant or guarantee that the information is complete or error free. The information seen here does not supersede the PJM Operating Agreement or the PJM Tariff both of which can be found by accessing: http://www.pjm.com/documents/agreements/pjm-agreements.aspx

For additional detailed information on any of the topics discussed, please refer to the appropriate PJM manual which can be found by accessing: http://www.pjm.com/documents/manuals.aspx

Contents

Executive Summary

Load Management Demand Resources (DR) has the ability to participate as a capacity resource in the PJM capacity market (Reliability Pricing Model or RPM) or to support a Load Serving Entity's Fixed Resource Requirement (FRR) plan. There were five DR products available during the 2018/2019 Delivery Year: for RPM commitments – Base DR and Capacity Performance DR were available; for FRR commitments – Limited DR, Summer Extended DR, Annual DR were also available. This is the third year that the Capacity Performance product has been available and the first year for the Base product.

A Curtailment Service Provider (CSP) is the PJM member that nominates the end use customer location(s) as a capacity resource and is fully responsible for the performance of the resource. Load Management products are required to respond to PJM Pre-Emergency or Emergency Load Management events, based on the availability period for each product (see Table 2: DR product availability), or receive a penalty. PJM may declare Emergency Load Management events outside the required availability window but does not measure capacity compliance in such cases (resources are eligible for emergency energy revenue if they reduce load). Load Management that is not dispatched during its availability period must perform a mandatory test to demonstrate it can meet its capacity commitment or receive a penalty.

Table 1 shows both the mandatory event and test performance values for the past 10 delivery years. In the years where there was more than one event, the event performance is the event MW weighted average of all of the events. PJM Load Management events outside the mandatory compliance period are excluded from the results. To date there have been no Load Management events in the 2018/19 delivery year (the last mandatory Load Management event was on 9/11/2013). Since there were no events, Base and Limited DR resources were required to test between June and September. The test results are available (performance = 148%) in this report. Since other products are required to be available in May, and can also test in May if there are no events, we will not know the performance of the other products until after the delivery year. Historically, test performance has been substantially higher than event performance which is largely a function of the difference in the test requirements compared to what a resource must do when dispatched during Load Management Event.

Table 1: Annual performance summary. Only events with mandatory compliance are included.

Delivery year	Event performance	Test performance
2009/10	No Events	118%
2010/11	100%	111%
2011/12	91%	107%
2012/13	104%	116%
2013/14	94%	129%
2014/15	No Events	144%
2015/16	No Events	134%
2016/17	No Events	153%
2017/18	No Events	163%
2018/19	No Events*	148%

* As of the time of this report

Overview

PJM Interconnection, L.L.C. procures capacity for its system reliability through the Reliability Pricing Model (RPM). The sources for meeting system reliability are divided into four groups:

1) Generation Capacity
2) Transmission Upgrades
3) Load Management (Pre-Emergency and Emergency Demand Resources)
4) Energy Efficiency

There were five Load Management Products available during the 2018/19 Delivery Year[1]: Limited DR, Extended Summer DR, Annual DR, Base DR and Capacity Performance DR. The availability period for each of the products is detailed in Table 2. By default, the interruptions must be implemented within thirty minutes of notification by PJM. Those resources that cannot be fully implemented within thirty minutes of notification and qualify for an exception may respond within either 60 or 120 minutes depending on their capabilities.

Table 2: DR product availability window.

DR Product	Max. interruptions	Max. event duration (hrs)	Availability period	Availability Hours (EPT)
Limited	10	6	June – September Non-NERC Hol. Wkdys.	12PM – 8PM
Base	Unlimited	10	June – September	10AM – 10PM
Extended Summer	Unlimited	10	June – October, May	10AM – 10PM
Annual/ Capacity Performance	Unlimited	12 15	June – October, May November - April	10AM – 10PM 6AM – 9PM

DR compliance can be more complex to measure than compliance for generation resources meeting their capacity obligations. In order to ensure the reliability service for which a resource is paid has actually been provided, PJM utilizes two different types of measurement and verification methodologies. DR Resources can choose the most appropriate of the following measurement methodologies:

- Firm Service Level (FSL) – Load Management achieved by a customer reducing its load to a pre-determined level. The customer must be able to reduce load below the pre-determined level which must be lower than the amount of capacity reserved for the customer as represented by the peak load contribution (PLC).
- Guaranteed Load Drop (GLD) – Load Management achieved by a customer reducing its load below the PLC when compared to what the load would have been absent the PJM event or test.

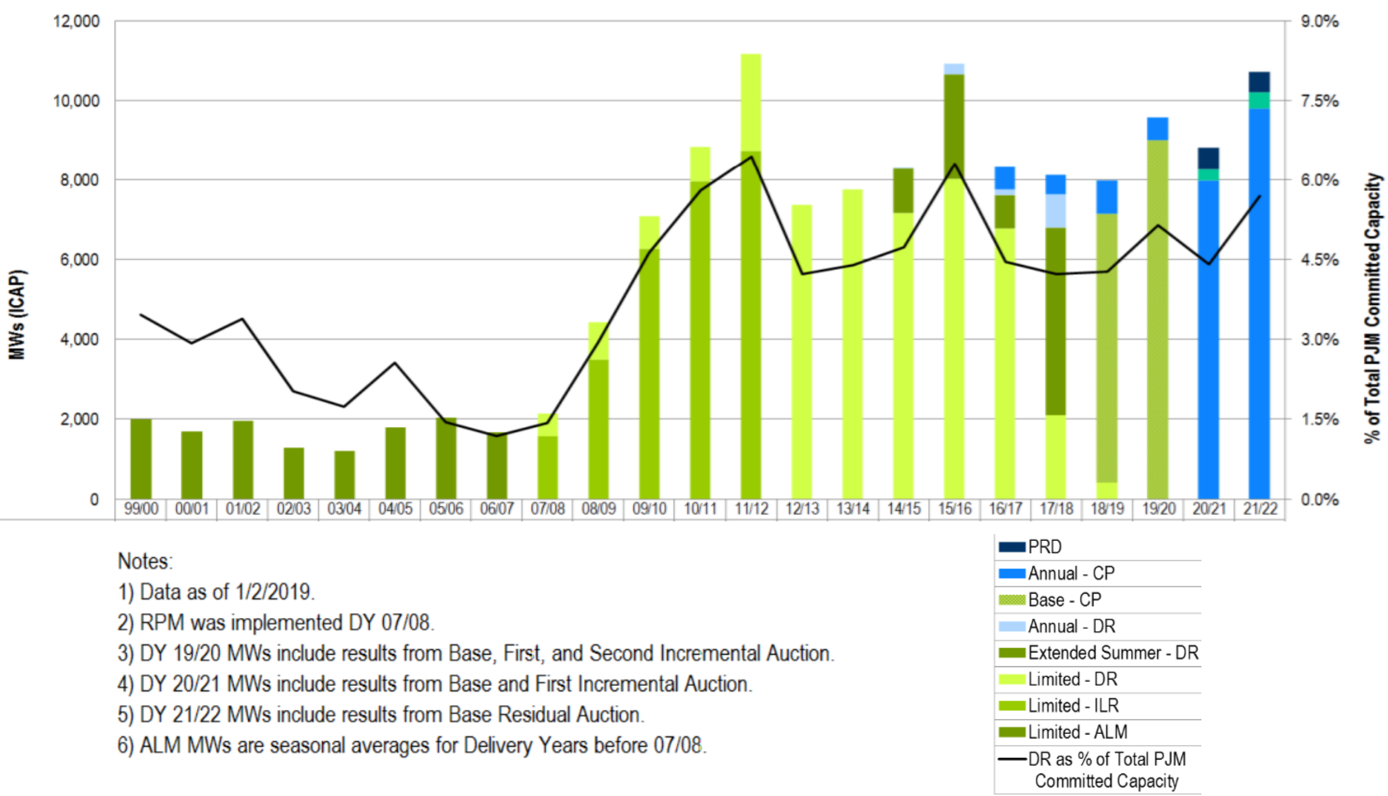
[1] The Delivery Year for the capacity construct corresponds to PJM's Planning Year which runs each year from June 1 until May 31 of the following year.

Participation Summary

The capacity values in this report are in terms of either Installed Capacity (ICAP) or Unforced Capacity (UCAP) depending upon which is most relevant. PJM calculates the Resource amounts required to meet the reliability standard in terms of UCAP which is also utilized to measure compliance with RPM commitment. PJM determines the UCAP value of different types of Resources based on methods described in the PJM manuals.

Figure 1 shows Load Management Commitments by Delivery Year from 1999/2000 through 2021/22 based on what cleared in the RPM auctions (BRA, IAs, and CP Transition Auctions) or as part of a LSEs FRR plan. Load Management participation in the PJM capacity market substantially increased from the 2007/08 Delivery Year through the 2011/12 Delivery Year, then declined, and has varied since. The final commitment values for the next three Delivery Years are uncertain since the values can still be adjusted in the Incremental Auctions and via Replacement Capacity Transactions. For the 2018/19 Delivery Year, Load Management capacity commitments represented 7,993MW of ICAP while total registered Load Management represented 8,946 MW. Registered Load Management may be in excess of the commitment if the CSP has indicated they have the potential to deliver an amount that is higher than their actual commitment[2].

Figure 1: PJM Demand Response Committed MWs by Delivery Year



[2] For example, a CSP may clear 10 MW of resources in an RPM auction but register 11 MW load reduction capability by end use customers to fulfill such commitment.

Table 3 shows the committed ICAP by Product Type (Limited DR, Annual DR, Base DR, Capacity Performance DR) for each of the 20 PJM zones for the 2018/19 Delivery Year. Note, there was no Extended Summer DR registered during this delivery year. Fifty-two PJM members or affiliates operate as a Curtailment Service Provider and over 2 million end use customers across almost every segment (residential, commercial, industrial, government, education, agricultural, etc.) participate as Load Management resources.

Table 3: Committed ICAP (MW) by Product Type and Zone for the 2018/19 Delivery Year.

Zone	Limited DR	Annual DR	Base DR	Capacity Performance	Total
Atlantic City Electric (AECO)			107.1		107.1
American Electric Power (AEP)	427.3		932.2	68.1	1427.6
Allegheny Power (APS)			499.1	59.1	558.2
American Transmissions Systems Inc. (ATSI)			546.6	162.6	709.2
Baltimore Gas and Electric (BGE)			382.6	70.1	452.7
Commonwealth Edison (COMED)		6.8	1316.6	26.2	1349.6
Dayton Power & Light (DAY)			152.5	13.2	165.7
Duke Energy Ohio & Kentucky (DEOK)			126.9	44.2	171.1
Dominion Virginia Power (DOM)			559.2	12.5	571.7
Delmarva Power & Light (DPL)			305.6	17.8	323.4
Duquesne Light (DUQ)			84	4.6	88.6
East Kentucky Power Cooperative (EKPC)				117.7	117.7
Jersey Central Power & Light (JCPL)			105.6		105.6
Metropolitan Edison (METED)			177.6	0.7	178.3
PECO (PECO)			265.7	5.3	271
Pennsylvania Electric Company (PENELEC)			193	39.6	232.6
Pepco (PEPCO)			462.3	27.5	489.8
Pennsylvania Power & Light (PPL)			278.6	173.8	452.4
Public Service Enterprise Group (PSEG)			218.6	0.1	218.7
Rockland Electric Company (RECO)			1.8		1.8
Total	427.3	6.8	6715.6	843.1	7992.8

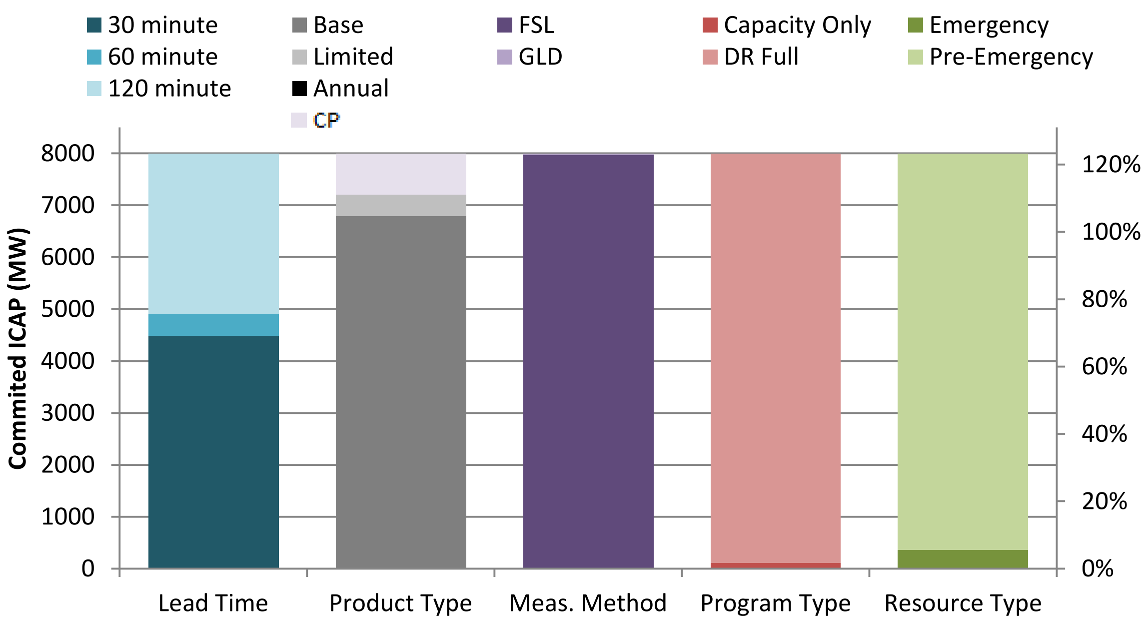
Load Management resources are registered by Lead Time, Product Type, Measurement Method, Program Type, and Resource Type. Figure 2 shows the breakdown of Committed ICAP for each item. 56% of resources were able to respond in 30 minutes, while 38% qualified for a 120 minute exception, and the remaining 5% qualified for a 60 minute exception.

The Product Type commitment level is determined by what is cleared in the RPM auctions. 5% of committed ICAP is Limited, 0.1% is Annual, 85% is Base, and the remaining 10% is Capacity Performance (see Figure 2). The compliance measurement method is 99.7% Firm Service Level (FSL), and only 0.3% Guaranteed Load Drop.

Figure 2 shows that 98.6% of committed ICAP is registered as Load Management DR Full. The remaining 1.4% is registered as Capacity Only. Load Management Full resources are eligible to receive both a capacity revenue stream as well as an emergency energy revenue when there is Load Management event. Capacity Only receives capacity payments but is not eligible for emergency energy payments during Load Management events and is typically only used for legacy EDC related tariff requirements or for registrations that participate with two different CSPs.

Load Management resource designations are split into Pre-Emergency and Emergency. The default designation is Pre-Emergency; Figure 2 shows that 95% of committed ICAP fell into this category. The Emergency classification is for those resources that use behind the meter generation and have environmental restrictions that permit them to run only during PJM emergency conditions. 5% of resources met this condition.

Figure 2: Committed ICAP for DR by Resource Type, Lead Time, Program Type, and Measurement Method for the 2018/19 Delivery Year.



Test Requirement Overview

If a Load Management Registration is not called in a mandatory Load Management event, the CSP must test the Registration. The Load Management Test is initiated by a Curtailment Service Provider (CSP) that has a capacity commitment. The CSP must simultaneously test all Registrations of the same product type in a Zone if PJM has not called a mandatory event for those Registrations. If a PJM-initiated Load Management Event is called for those Registrations during the product availability period, there is no test requirement and no Test Failure Charges would be assessed to a CSP for those registrations. Rather, their performance will be based on the Load Management events.

The timing of a Load Management Test is intended to represent the conditions when a PJM-initiated Load Management event might occur in order to assess performance during a similar period. The Base and Limited Products must be tested on a non-holiday weekday from June – September between 12PM and 8PM of that Delivery Year. The Annual, and Capacity Performance Products must be tested on a non-holiday weekday in June – October or May from 10AM – 10PM. The requirement to test all resources in a zone simultaneously is necessary to ensure that test conditions are as close to realistic as possible. It is requested that the CSP notify PJM of intent to test 48 hours in advance to allow coordination with PJM dispatch.

There is no limit on the number of tests a CSP can perform. However, a CSP may only submit data for one test to be used by PJM to measure compliance. If the CSP's Zonal Resources collectively achieve a reduction greater than 75% of the CSP's committed MW volume during the test, the CSP may choose to retest the Resources in that Zone that failed to meet their individual nominated value.

Load Management Resources are assessed a Test Failure Charge if their test data demonstrates that they did not meet their commitment level. The Test Failure Charge is calculated based on the CSP's Weighted Daily Revenue Rate which is the amount the CSP is paid for their RPM commitments in each Zone. The Weighted Daily Revenue Rate takes into consideration the different prices DR can be paid in the same Zone. For example, a CSP can clear DR in the Base Residual and/or Incremental Auctions in the same Zone, all of which are paid different rates. The penalty rate for under-compliance is the greater of 1.2 times the CSP's Weighted Daily Revenue Rate or $20 plus the Weighted Daily Revenue Rate. If a CSP didn't clear in a RPM auction in a Zone, the CSP-specific Revenue Rate will be replaced by the PJM Weighted Daily Revenue Rate for such Zone.

Test Performance

Since there have been no Load Management events during the 2018/2019 Delivery Year so far, all Base DR and Limited DR resources that are committed for the Delivery Year were required to perform tests to assess their performance capability. 7,141 MW (ICAP) were committed as Base or Limited DR Load Management Resources. The net result of the testing for Base and Limited DR was 10,603 MW of over-compliance or a performance level of 148% across all zones. Table 4 shows the results, to date, by product type. The zonal level results for Base and Limited DR are in Table 5. The net result for each zone is over-compliance. There were some individual CSPs whose tests resulted in under compliance.

Table 4: Load Management commitments, compliance, and test performance (ICAP) by product, DY2018/19

Product	Test commitment (MW)*	Reduction (MW)	Over/under performance (MW)	Performance	Re-test
Limited	427	482	55	113%	0
Base	6,716	10,120	3,404	150%	1.7%
Annual	6.8	N/A	N/A	N/A	N/A
Capacity Performance	843	N/A	N/A	N/A	N/A
Total	**7,993**	N/A	N/A	N/A	N/A

Table 5: Load Management commitments, compliance, and test performance for Base and Limited DR resources (ICAP by Zone, DY2018/19)

Zone	Committed ICAP (MW)	Test commitment (MW)*	Reduction (MW)	Over/under performance (MW)	Performance	Re-test
AECO	107.1	107.1	114.5	7.4	107%	3.2%
AEP	1352.3	1352.2	1609.8	250.4	118%	3.5%
APS	499.1	499.1	556.3	57.2	111%	1.2%
ATSI	546.6	546.6	615.6	69.0	113%	2.2%
BGE	382.6	382.6	1949.2	1566.6	509%	0.0%
COMED	1315.1	1315.1	1448.5	133.4	110%	2.5%
DAY	152.5	152.5	212.1	59.7	139%	0.0%
DEOK	126.9	126.9	236.3	109.4	186%	0.0%
DOM	559.2	559.2	710.1	151.0	127%	1.3%
DPL	305.6	305.6	681.5	375.9	223%	1.6%
DUQ	84.0	84.0	109.1	25.1	130%	0.0%
JCPL	105.6	105.6	128.0	22.4	121%	1.6%
METED	177.6	177.6	188.5	10.9	106%	2.4%
PECO	265.7	265.6	307.1	41.5	116%	3.5%
PENELEC	193.0	192.9	209.6	16.6	109%	2.1%
PEPCO	462.3	462.3	929.9	467.6	201%	0.0%
PPL	279.0	279.0	340.9	61.9	122%	7.8%
PSEG	218.2	218.1	252.8	34.7	116%	0.0%
RECO	1.8	1.8	3.2	1.4	176%	0.0%
Total	7,141.4	7,140.9	10,602.9	3,462	148%	1.7%

* *Test commitment = Commitment ICAP – Daily Deficiency MW*

Test Failure Charges for the 2018/19 Delivery Year are applied on an individual CSP/Zone basis for settlement purposes. The Test Failure Charges are reported on an aggregate basis here to preserve confidentiality. The weighted average Penalty Rate for Base and Limited DR resources for the 2018/19 Delivery Year is $187/MW-day and $180/MW-day respectively. The annual penalties for Base and Limited DR under-compliance total about $1.1M which will be allocated to RPM LSEs pro-rata based on their Daily Load Obligation Ratio. Therefore, the under-compliance penalties at the time of this report (i.e. Base and Limited DR only) are about 0.17% of the total expected annual RPM Load Management credits ($638M) this year. Table 6 below shows Penalties by Product for the 2018/2019 Delivery Year thus far.

Table 6: Load Management Test Penalties by Product, DY2018/19

Product	Penalties $	Shortfall (MW)	Average Weighted Penalty Rate ($/MW-day)	Penalties as % of Total LM Credits ($638M)
Base	$ 1,110,134	14.9	$187	0.17%
Limited	$ 2,100	0.03	$180	Very small
Capacity Performance	N/A	N/A	N/A	N/A
Annual	N/A	N/A	N/A	N/A
Total	**$1,112,234**	**14.93**	**$187**	**0.17%**

Resources that are short on Committed MWs face the deficiency charges. Deficiency charges are applied based on the amount of days in the year the resource is deficient of Committed MWs. Participants can make replacement transactions for future deficiencies which would change these values. Thus, data in the table below may change based on ongoing replacement transactions. As of January 30th, 2019 there was only one deficiency for 1 day.

Table 7: Load Management Deficiency Charges by Product, DY2018/19

Zone	Average Weighted Deficiency Charge ($/MW-day)	Total charges through 1/30 ($)	Deficiency Charges as % of Total LM Credits through 1/30 ($638M)
Base	$253	$253	Very small
Limited	0	0	0
Capacity Performance	0	0	0
Annual	0	0	0
Grand Total	**$253**	**$253**	**Very small**

Exhibit 3(c)

Exhibit 3(c) **Docket No. ER19-1661**

Customer 1			
Date	Hour	Description	Percent Reduction in Demand 1-CP Hour Compared to NCP Hour
02/20/2015	HE08	DOM Zone 1-CP Hour	-98.7%
	HE03	Customer's NCP Hour	
07/25/2016	HE17	DOM Zone 1-CP Hour	-80.3%
	HE09	Customer's NCP Hour	
01/09/2017	HE08	DOM Zone 1-CP Hour	-29.2%
	HE15	Customer's NCP Hour	
01/07/2018	HE08	DOM Zone 1-CP Hour	-33.9%
	HE01	Customer's NCP Hour	
01/31/2019	HE08*	DOM Zone 1-CP Hour	-8.4%
	HE24	Customer's NCP Hour	

Customer 2			
Date	Hour	Description	Percent Reduction in Demand 1-CP Hour Compared to NCP Hour
02/20/2015	HE08	DOM Zone 1-CP Hour	-98.5%
	HE03	Customer's NCP Hour	
07/25/2016	HE17	DOM Zone 1-CP Hour	-83.0%
	HE01	Customer's NCP Hour	
01/09/2017	HE08	DOM Zone 1-CP Hour	-61.4%
	HE14	Customer's NCP Hour	
01/07/2018	HE08	DOM Zone 1-CP Hour	-42.0%
	HE01	Customer's NCP Hour	
01/31/2019	HE08*	DOM Zone 1-CP Hour	-32.2%
	HE24	Customer's NCP Hour	

Customer 3			
Date	Hour	Description	Percent Reduction in Demand 1-CP Hour Compared to NCP Hour
02/20/2015	HE08	DOM Zone 1-CP Hour	-20.5%
	HE11	Customer's NCP Hour	
07/25/2016	HE17	DOM Zone 1-CP Hour	-30.6%
	HE14	Customer's NCP Hour	
01/09/2017	HE08	DOM Zone 1-CP Hour	-26.5%
	HE10	Customer's NCP Hour	
01/07/2018	HE08	DOM Zone 1-CP Hour	-26.7%
	HE06	Customer's NCP Hour	
01/31/2019	HE08*	DOM Zone 1-CP Hour	-22.1%
	HE10	Customer's NCP Hour	

Customer 4			
Date	Hour	Description	Percent Reduction in Demand 1-CP Hour Compared to NCP Hour
02/20/2015	HE08	DOM Zone 1-CP Hour	-31.0%
	HE11	Customer's NCP Hour	
07/25/2016	HE17	DOM Zone 1-CP Hour	-51.7%
	HE08	Customer's NCP Hour	
01/09/2017	HE08	DOM Zone 1-CP Hour	-51.5%
	HE05	Customer's NCP Hour	
01/07/2018	HE08	DOM Zone 1-CP Hour	-11.4%
	HE04	Customer's NCP Hour	
01/31/2019	HE08*	DOM Zone 1-CP Hour	-0.4%
	HE06	Customer's NCP Hour	

* 2019 year to-date