Appendix B: Rate Design Methodology - Technical Details

The rate design development for TOD is intended to be revenue neutral to Residential General and Space Heating customers. Minnesota Power's approach to TOD rate design is summarized in the steps below.

1. Determine the annual residential Authorized Revenue
2. Allocate each cost driver's required revenue to all hours of a year
3. Determine a peak period schedule
4. Calculate final rates by peak period

1. Determine the Annual Residential Authorized Revenue:

The total base Authorized Revenue (plus fuel) for Residential General and Space Heating customers resulting from Minnesota Power's (or, "the Company") recent 2019 Rate Case resolution[1] is $107.7 million. Customer costs (such as metering and administration costs) are fixed and are not impacted by level of demand or load on Minnesota Power's system, so the $8 customer service charge totaling $10.5 million is netted from total revenue associated with electric rates to arrive at $97.2 million that can be allocated for TOD rate development. Table 1 shows the Minnesota Public Utilities Commission (or, the "Commission")-approved annual Authorized Revenue allocated to the residential General and Space Heating classes of $97.2 million, broken down into demand/capacity, energy, and customer cost classification according to recent cost to serve analysis. Table 1 also shows the kWh sales associated with this annual Authorized Revenue.

[1] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E015/GR-19-442,

Table 1: Authorized Revenue (Excluding Customer Charge)

Classification	Residential Authorized Revenue
Fixed (Excl. Customer Charge)	15.8
Demand	46.0
Energy	35.3
Total Revenue (Million $)	**97.2**
Total Energy (Million kWh)	934.1

Total Residential General and Space Heating customer revenue is then adjusted per the low-income, usage qualified customer discount. The low income, usage qualified discount is applied as a flat 3.2 cent discount on the non-discounted rates, and the non-discounted authorized revenue is what's allocated in steps 2 and 3 of the rate design process.

Authorized revenue associated with the low income, usage qualified discount was calculated by first determining the discount parameters – the desired percent discount to the standard rate (30%), the kWh level the discount would apply to for those eligible (first 600 kWh) and the usage eligibility threshold (1000 kWh). The Company was able to estimate the kWh and revenue associated with both the discount and standard rate using the above stated parameters as well as: historical Low Income Home Energy Assistance Program ("LIHEAP") and non-LIHEAP customer counts, an assumption for how many low-income customers would self-declare, and the average annual kWh consumption for LIHEAP and non-LIHEAP customers (estimated based on historical billing data).

Table 2 shows the total Authorized Revenue and kWh estimate for Residential General and Space Heating customers by cost classification for total, discounted energy use, and the revenue expected from non-discounted, or "standard" usage. Table 3 divides the authorized revenue by the estimated energy consumption to show authorized revenue in cents/kWh.

Table 2: Total Authorized Revenue Residential General and Space Heating

		Residential (20, 22) Authorized Revenue		
Classification	**Hourly Allocation**	**Total**	**Discount**	**Non-Discount**
Fixed (Excl. Customer Charge)	Evenly Allocated	16	1	15
Demand	MP System Load	46	4	42
Energy	Locational Marginal Price	35	3	32
Total Revenue (Million $)		**97**	**8**	**89**
Total Energy (Million kWh)		934	104	830

Table 3: Authorized Revenue under a cent/kWh basis

	Residential (20, 22) Authorized Revenue Cent per kWh basis		
	Total	**Discount**	**Non-Discount**
Fixed (Excl. Customer Charge)	1.7	1.2	1.7
Demand	4.9	3.6	5.1
Energy	3.8	2.7	3.9
Flat Rate (Cent/kWh)	**10.4**	**7.5**	**10.8**

2. Allocate Each Cost Driver's Authorized Revenue Across Hours

The non-discounted Authorized Revenue is allocated to all hours of the 2020 test year via the methods described in this section to produce the Standard and 601+ kWh (Eligible LI) rates for on, off, and super-off peak periods for all TOD rate options presented in this filing. The low-income, usage qualified ("0-600 kWh (Eligible LI)") rates are developed by applying a constant 3.2 cent discount to the Standard rates for all peak periods.

The annual non-discounted Authorized Revenue is allocated hourly based on: 1) Cost Classification (Fixed, Demand, Energy) and Allocation Method. Cost classification and the amount of overall cost assigned to each cost driver is determined by the Company's COSS, which identified the share of costs by classification. Table 4 shows the annual non-discounted Authorized Revenue by driver of costs/classification.

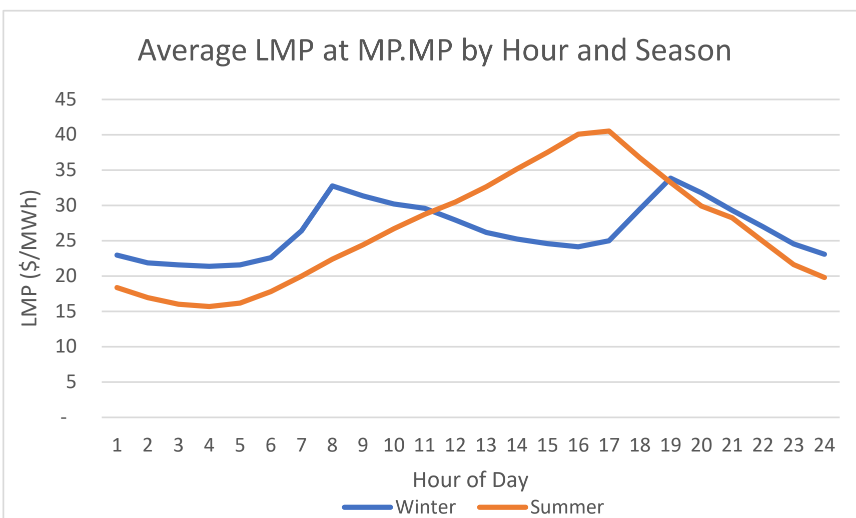
Table 4: Annual Non-Discounted Authorized Revenue by Driver of Costs/Classification

Classification	Hourly Allocation	Residential (20, 22) Authorized Revenue	Share of Revenue
Fixed (Excl. Customer Charge)	Evenly Allocated	15	16%
Demand	MP System Load	42	47%
Energy	Locational Marginal Price	32	36%
Total Revenue (Million $)		**89**	**100%**

Table 4 also shows the Hourly Allocation indicator: Fixed costs are allocated evenly across all hours, energy costs are allocated based on 2019 Midcontinent Independent System Operator ("MISO") Locational Marginal Prices ("LMP"), and Demand costs are allocated based on 2019 Minnesota Power System Demand[2] leveraging the "Cost Duration" method, which assigns more capacity costs to periods of high load or the annual peak.

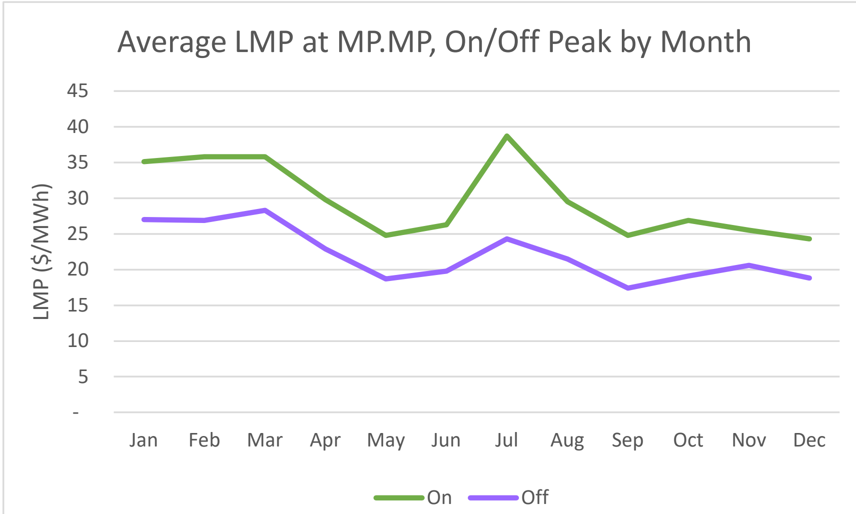
Figures 1 and 2 below summarize the hourly LMP at the MISO MP load node for 2019. Both Figures 1 and 2 illustrate the seasonal price fluctuations, the difference between on and off-peak prices, and the daily shape during the winter and summer seasons.

Figure 1: Average LMP at MP.MP by House and Season



[2] Net of any customer generation meeting customer demand.

Figure 2: Average LMP at MP.MP, On/Off Peak by Month



Demand-related Authorized Revenue are allocated via the "Cost Duration" methodology developed by Lon Huber of Navigant Consulting. This is the same methodology as was used in the February 2019 Compliance Filing.[3] The cost duration method assigns a share of Demand costs to each hour in a way that reflects the system's usage, and is documented in the steps below.

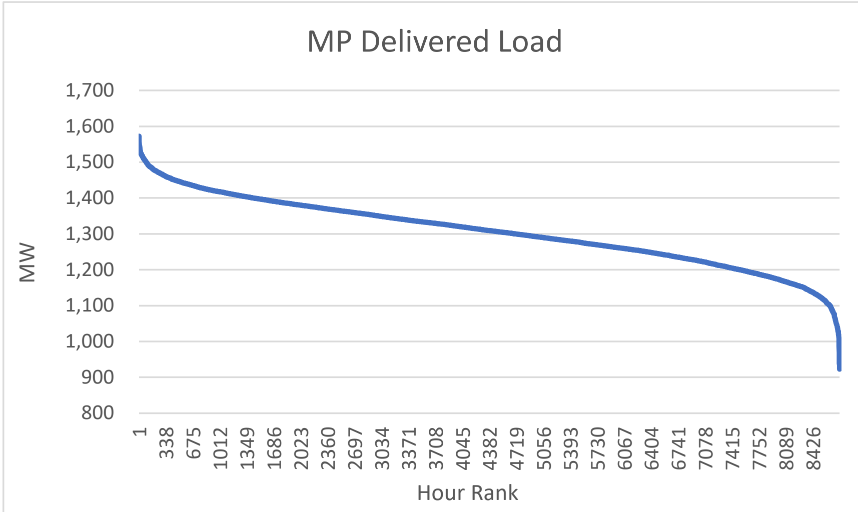
Cost Duration Method

Minnesota Power's system load[4] duration curve in Figure 3 shows that some capacity assets are only used to meet demand during a small number of "peak" hours. Thus, it would be appropriate to assign a significant share of costs for these peaking assets to the hours that rank highest on the load duration curve. Similarly, there is a minimum load or "baseload" demand which all hours of the year exceed. Thus, there is some portion of costs which should be assigned equally to all 8,760 hours of the year.

[3] In the Matter of Minnesota Power's Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project Docket No. E015/M-12-233

[4] Net of any customer generation meeting customer load

Figure 3: MP Delivered Load



Step 1: Calculate the incremental load in each hour

The incremental load in each hour is calculated by taking the difference in load between that hour and the hour with the next highest load. For the lowest load hour of the year, the load in that hour is not used. Note that the sum of all these incremental load amounts is equal to the difference of the annual peak load and the lowest load hour in the year

For example, Minnesota Power's peak load in 2019 was 1573 MW, and was 12 MW higher than the second highest hour, which is in turn 3 MW higher than the third highest hour, which is in turn 7.3 MW higher than the fourth highest hour, and so on. The lowest load hour of 2019 has load of 922 MW.

Step 2: Share the incremental load across higher hours

For each hour, the incremental load is shared evenly between the hour in question and all hours of the year that have a higher load than the hour in question. The incremental load at the highest load hour is not shared as there are no higher load hours. The incremental load at the second highest hour is shared evenly between the top two hours, so each gets a one-half share.

For example, the 12 MW incremental load in the highest load hour is allocated only to that hour. 1.45 MW of the 2.9 MW incremental load in the second highest hour is allocated to that second-highest hour and the other 1.45 MW is allocated to the highest load hour. The 7.3 MW incremental load in the third highest hour is shared across the top three hours (2.4 MW of load assigned to the highest, second highest, and third highest), and so on.

Step 3: Total the load allocated to each hour

The load allocated to each hour is then cumulated. The highest load hour has a share of load for all hours of the year, the second highest load hour has a share of load for all hours of the year except the highest hour, and so on.

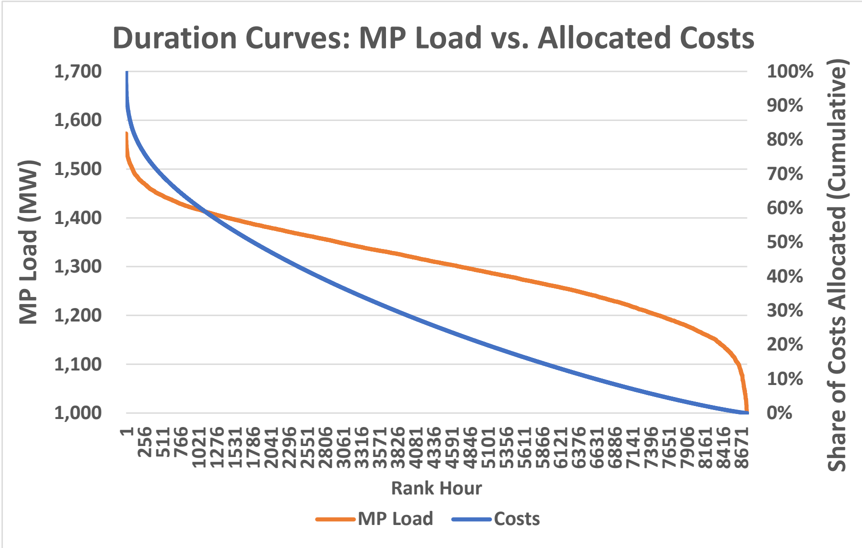
For example, totaling all the load allocated to the highest load hour (12 MW plus 1.45 MW plus 2.4 MW plus…) gives 19.7 MW, for the second highest hour (1.45 MW plus 2.4 MW plus…) gives 7.2 MW, and so on for each hour.

Step 4: Calculate the Capacity Cost Allocation Factor

The incremental loads allocated to each hour in Step 4 are then divided by the total incremental load (i.e. 650 MW = 1573 – 922) to produce the share of incremental load served in each hour. The resulting hourly series totals to 100% and is used to allocate the capacity component of the residential Authorized Revenue by hour.

As illustrated in Figure 4 below, the costs are spread to each hour in a manner that closely resembles the load duration curve and therefore reflects system use. This spread of costs to each hour is known as the “Cost Duration Curve.”

Figure 4: Duration Curves: MP Load vs. Allocated Costs



After allocating all categories of cost by hour, it's possible to aggregate the estimated cost to serve residential demand in each hour of the year. Table 5 shows the average hourly estimated costs of serving residential loads by season and illustrates the relative magnitude in each hour by color.

Table 5: Cost to Serve by Season/Hour

	Cost to Serve by Season/Hour			
	Winter	Spring	Summer	Autumn
Hour (ending)	Nov-Feb	Mar-May	Jun-Aug	Sep-Oct
1	7.9	7.4	7.4	7.5
2	7.8	7.3	7.3	7.4
3	7.7	7.3	7.2	7.3
4	7.7	7.3	7.2	7.4
5	7.7	7.4	7.2	7.4
6	9.5	9.2	8.8	9.1
7	10.1	9.7	9.0	9.4
8	11.2	10.1	9.3	9.7
9	11.5	10.2	9.6	9.8
10	11.9	10.2	9.9	10.0
11	12.4	10.1	10.2	10.0
12	11.9	10.1	10.7	10.1
13	11.5	10.0	11.2	10.1
14	11.3	10.0	11.8	10.3
15	11.2	10.0	13.0	10.3
16	12.4	11.3	14.3	11.7
17	13.0	11.1	15.8	11.6
18	18.5	11.0	13.2	11.3
19	14.7	11.0	12.1	11.3
20	13.2	11.2	11.5	11.2
21	10.8	9.6	9.7	9.5
22	10.1	9.3	9.4	9.2
23	9.7	9.1	9.1	9.0
24	8.0	7.5	7.4	7.5

The highest cost hours (shaded green) occur in two distinct periods: winter evenings, particularly in December and January[5], and summer afternoons, particularly in July. The high-cost winter evening and summer afternoon hours reflect the high demand on Minnesota Power's transmission and distribution systems, as well as moderately high MISO LMPs at the MP load node. Lowest cost periods (shaded red) mostly occur overnight and reflect the combination of low demand on Minnesota Power's systems, and low MISO market prices.

Costs vary significantly between hours, with the cost to serve load in highest cost hours being more than four times higher than in the lowest cost hours. This variance, while

[5] Although, in the 2019 Annual peak occurred in November and this is evident in the calculated cost to serve.

significant, is not as large as other utilities' where times of high system demand and high LMPs are more closely aligned.

3. Determine Peak Period Selection

Selecting TOD periods requires balancing a number of different goals such as simplicity for customers (and the utility) and desired size of on-peak to super off-peak price ratios. A peak period narrowly targeted at highest costs hours that may vary by season (perhaps with two distinct peak periods in a day), will lead to sharper pricing ratios but may be more challenging for customers and the utility to manage. In contrast, a more broadly targeted peak period, such as one that applies for a larger number of hours year-round, will lead to more muted pricing differentials but may be more appealing to customers.

The Company initially examined two TOD period options and associated rates in its 2018 TOD stakeholder process that contrasted in their degrees of targeting and simplicity. The TOD periods were reviewed and refined through the stakeholder process to arrive at 3 Options presented in the 2019 TOD Compliance Filing. The Company re-considered the three peak period designs from its 2019 TOD Compliance Filing and developed an additional, more highly targeted structure in this iteration in attempt to achieve a significantly higher price differential. These peak period designs are summarized below in Figure 5. Periods highlighted in red denote the higher price on-peak periods, yellow denotes the off-peak periods, and green denotes the discounted super off-peak periods.

Figure 5: On-Peak, Off-Peak, and Super Off-Peak Periods by Rate Design

Feb 2019 Filing: Option 1

Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Feb	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Mar	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Apr	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
May	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Jun	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Jul	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Aug	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Sep	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Oct	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Nov	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Dec	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1

Feb 2019 Filing: Option 2

Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Feb	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Mar	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Apr	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
May	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Jun	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Jul	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Aug	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Sep	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Oct	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Nov	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Dec	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1

Feb 2019 Filing: Option 3

Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	-1
Feb	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	-1
Mar	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	-1
Apr	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	-1
May	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	-1
Jun	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	-1
Jul	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	-1
Aug	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	-1
Sep	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	-1
Oct	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	-1
Nov	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	-1
Dec	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	-1

Highly Targeted, High On/Off Rate Ratio

Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-1	-1	-1	-1	-1	-1	0	1	1	1	1	0	0	0	0	0	0	1	1	1	1	0	0	-1
Feb	-1	-1	-1	-1	-1	-1	0	1	1	1	1	0	0	0	0	0	0	1	1	1	1	0	0	-1
Mar	-1	-1	-1	-1	-1	-1	0	1	1	1	1	0	0	0	0	0	0	1	1	1	1	0	0	-1
Apr	-1	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
May	-1	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Jun	-1	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	-1
Jul	-1	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	-1
Aug	-1	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	-1
Sep	-1	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Oct	-1	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Nov	-1	-1	-1	-1	-1	-1	0	1	1	1	1	0	0	0	0	0	0	1	1	1	1	0	0	-1
Dec	-1	-1	-1	-1	-1	-1	0	1	1	1	1	0	0	0	0	0	0	1	1	1	1	0	0	-1

Stakeholders and the Company considered the more complex, targeted peak period structures infeasible, especially for initial phases of TOD rate introduction. “Option 2” from the Company's previous TOD Compliance filing was selected as the preferred TOD peak period design for all TOD rates presented in this filing: "Updated 2019 Option 2", "Alt. 4:1", and "Alt 5:1."

The "Updated 2019 Option 2" and the Alt 4:1 rates are similar, and differ only in their allocation of demand revenue; the 4:1 attributes no demand/capacity revenue to the super off-peak period, while the "Updated 2019 Option 2" does. The "Updated 2019 Option 2" and the Alt 4:1 rates are both supported by the Company's cost of service study, while the Alt 5:1 rate is not. The Alt 5:1 rate was developed in cooperation with stakeholders to artificially feature both: 1) a high on to super-off-peak price differential (5:1), and 2) a simple, un-targeted peak-period schedule (February 19 Filing "Option 2"). These features cannot exist in the same rate and remain consistent with the Company's estimates of cost to serve; i.e. this rate would periodically over and then undercharge customers in a way that's not conducive to overall system savings. A 5:1 rate that's consistent with Minnesota Power's calculated cost to serve if the peak period schedule is the "Highly Targeted, High On/Off Peak Ratio" and there are no capacity/demand costs allocated to the super off-peak period.

4. Calculate final rates by peak period

Once Authorized Revenue for non-discounted energy has been allocated by hour and peak periods defined, rates can be calculated for each peak period. Hourly costs and hourly energy usage are aggregated by peak period, and each period's aggregate costs can be divided by each period's respective usage to produce a distinct price for each peak period. Low-income, usage-qualified discount rates for each period are calculated by applying a constant 3.2 cent discount to the non-discounted rates. Final Alternative TOD rates used in the CUB bill impact analysis are shown in Table 6 below.

Table 6: Final Alternative TOD Rates for 2020 Bill Impact Analysis (cents/kWh)

Standard *(Applicable to all customers not eligible for the Low-Income Usage Qualified Discount)*	**Updated 2019 Option 2 (Ratio ~2:1)**	**Alt. w/ ~4:1 Ratio**	**Alt. w/ ~5:1 Ratio** ***(Bill Impact Analysis Only)***
Peak	14.9	17.3	20.7
Off-peak	10.7	11.0	10.3
Super off-peak	7.6	4.7	4.1
Peak period hours	3:00 PM – 8:00 PM weekdays	3:00 PM – 8:00 PM weekdays	3:00 PM – 8:00 PM weekdays
Off-peak period hours	All other times	All other times	All other times
Super off-peak period hours	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM

Low-Income Usage Qualified *(Applicable to customers eligible for discount)*	**Updated 2019 Option 2**	**Alt. w/ ~4:1 Ratio**	**Alt. w/ ~5:1 Ratio** ***(Bill Impact Analysis Only)***
Peak (0-600 kWh)	11.7	14.1	17.5
Peak (601+ kWh)	14.9	17.3	20.7
Off-peak (0-600 kWh)	7.5	7.8	7.1
Off- Peak (601+ kWh)	10.7	11.0	10.3
Super off (0-600 kWh)	4.3	1.5	0.8
Super off (601+ kWh)	7.6	4.7	4.1

**Rates include cost of fuel and purchased energy*