BELMONT LIGHT
POWERING YOUR COMMUNITY SINCE 1898

Memorandum

To: Municipal Light Board

From: General Manager Craig Spinale, Energy Resources Manager Becca Keane, Energy Specialist Ben Thivierge,

Communications Coordinator Aidan Leary

Date: October 20, 2021

Re: Residential Time of Use Rate Recommendations

1. Summary

This memo provides recommendations for a time-of-use (TOU) rate for residential customers of Belmont Light, along with a summary of Belmont Light's plans for a pilot program. In conjunction with members of the Light Board Advisory Committee (LBAC) and the Municipal Light Board (MLB), Belmont Light staff has investigated the potential benefits, costs, and viability of residential TOU rates since late 2019. LBAC unanimously voted to recommend the proposed rates described here on April 7, 2021.

A set of six goals provides the guiding framework for our TOU efforts[1]. A prospective residential TOU rate will need to meet each of the goals:

- Align customers savings from reduced energy use with savings for Belmont Light
- Support strategic electrification
- Protect low-income customers
- Support energy efficiency and solar
- Ensure Belmont Light revenue sufficiency and stability
- Provide for easy implementation

Following consideration of eight different rate scenarios and over a dozen specific rate structures at 33 committee or board meetings and two public forums, Belmont Light and LBAC have identified a TOU rate option that, we believe, fulfills the suite of goals while also meeting additional criteria regarding customer satisfaction and effective rate design.

The proposed rate would comprise two seasonal on-peak periods: a 6-hour peak window in the "summer" months of June through September and a 4-hour peak window in the "non-summer" months of October through May. Other distinctive features of the rate include that weekends and holidays will follow the on and off-peak sequence and a time-varied buyback rate for ratepayers with solar who enroll in TOU.

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[1] The TOU goals were initially proposed by LBAC Member David Beavers in a memo dated January 2020 and presented to MLB on February 10, 2020.

The rate was designed as revenue neutral relative to Residential Rate A. This means that if all of Belmont Light's Rate A customers were placed on the new TOU rate and did not modify their normal consumption behavior, there would be no revenue impact to Belmont Light. Of course, our intention is to create more efficient consumption behavior via the rate. Modeling analyses that Belmont Light conducted with LBAC Member David Beavers indicate that, assuming a 20% shift from year-round on-peak consumption, an average Belmont Light customer would save approximately 5%, or $73, in annual billing costs. With a 20% shift, top-end users would save about 6% annually, an average EV customer 9%, an average heat pump customer 8%, and an average solar customer 17%. We are not currently recommending that customers on Belmont Light's Residential Low-Income Rate convert to the proposed TOU rate. Though, in pursuit of our goals, we did perform analysis that shows that the rate would not unduly harm lower-income ratepayers[2].

Belmont Light and LBAC recommend that we pilot the TOU rate through a one-year opt-in program so that we may collect data and determine whether the selected rate sufficiently meets the six goals in practice. From the pilot, we expect to yield approximately $10.27 in savings per avoided kW during monthly transmission peaks and $125 per avoided kW during the annual capacity peak. Total costs and/or savings from the pilot are difficult to predict as they will be determined by the number and types of customers enrolled and by their consumption behavior across the 12 months.

A successful pilot could serve as a model for other MLPs contemplating residential TOU structures. Based on our research, there is not an abundance of data available from nearby MLPs that illuminates the impacts of TOU rate design on the residential demographic. With our pilot, we hope to contribute meaningful data to a topic that has not been thoroughly investigated locally.

The remainder of this memo discusses the history of the TOU initiative to date (Section 2); the proposed rate design and potential impacts in more detail (Section 3); and our plans for the pilot program (Section 4). Appendix A provides results from our and LBAC's modeling of potential customer impacts.

2. Background

a) How did we get here?

Belmont Light commenced our exploration of TOU rate design in late 2019 following an introductory discussion with LBAC on October 16, 2019. Though the current conversation officially began at the committee level in 2019, TOU was a topic of interest for Belmont Light for several years prior. For instance, the prospect of TOU partially inspired our transition to advanced metering infrastructure (AMI) and the selection of our current billing system. These projects were completed in 2015 and 2016, respectively, making it feasible for Belmont Light to implement interval-based billing processes needed for TOU. "Innovative Rate Design" is a strategic initiative from our 2021-2026 Strategic Plan and customers have conveyed interest in TOU through emails to staff and customers surveys for several years.

b) Research

Industry-wide, TOU for commercial and industrial rate bases is more common than residential TOU offerings. We therefore found that there was not enough published information on residential TOU programs from nearby and/or comparable utilities to make for a rich literature review. Nonetheless, Belmont Light was able to conduct helpful qualitative research through interviews with other MLPs. In 2020 and 2021, staff spoke to several other

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[2] Our modeling indicates that if the Customer Charge were removed for Rate LI customers joining the proposed TOU rate, an average customer would save around 2% per year. However, a distinct rate design effort would be required for any low-income TOU offering.

public power utilities about their experiences with residential TOU. Insights from utilities that serve the communities of Concord, Groton, and Reading in Massachusetts, along with Glasgow, Kentucky and Fayetteville, North Carolina revealed three important themes to our team:

1) Communication with customers is key- for voluntary programs, uptake and behavior change depends on outreach and tailored education
2) Piloting is crucial- testing the rate and collecting early data helps in the long-term
3) Data analysis is challenging- prepare in advance to ensure data integrity

The literature that we did review, such as articles and studies published by the American Public Power Association[3] and the Brattle Group[4], repeated these themes.

Belmont Light and LBAC have carried these themes into our TOU rate design efforts and into the recommendations provided herein. We have a robust plan to educate and support customers leading up to and throughout a potential one-year pilot, and we have confirmed that the data collection processes of our AMI and billing systems are functioning well.

Other themes that emerged during our research were that any prospective TOU rates should be simple so that customers are attracted—rather than deterred—and the on-to-off peak pricing ratio should be high enough to induce behavior change.

c) What are we hoping to achieve?

A set of six TOU goals has guided Belmont Light's rate design efforts, analyses, discussions, and modeling. These goals encapsulate why Belmont Light is pursuing a TOU program and summarize the high-level benefits we hope to actualize through a new rate. Table 1, excerpted from a January 2020 memo authored by LBAC Member David Beavers, provides rationale for each goal.

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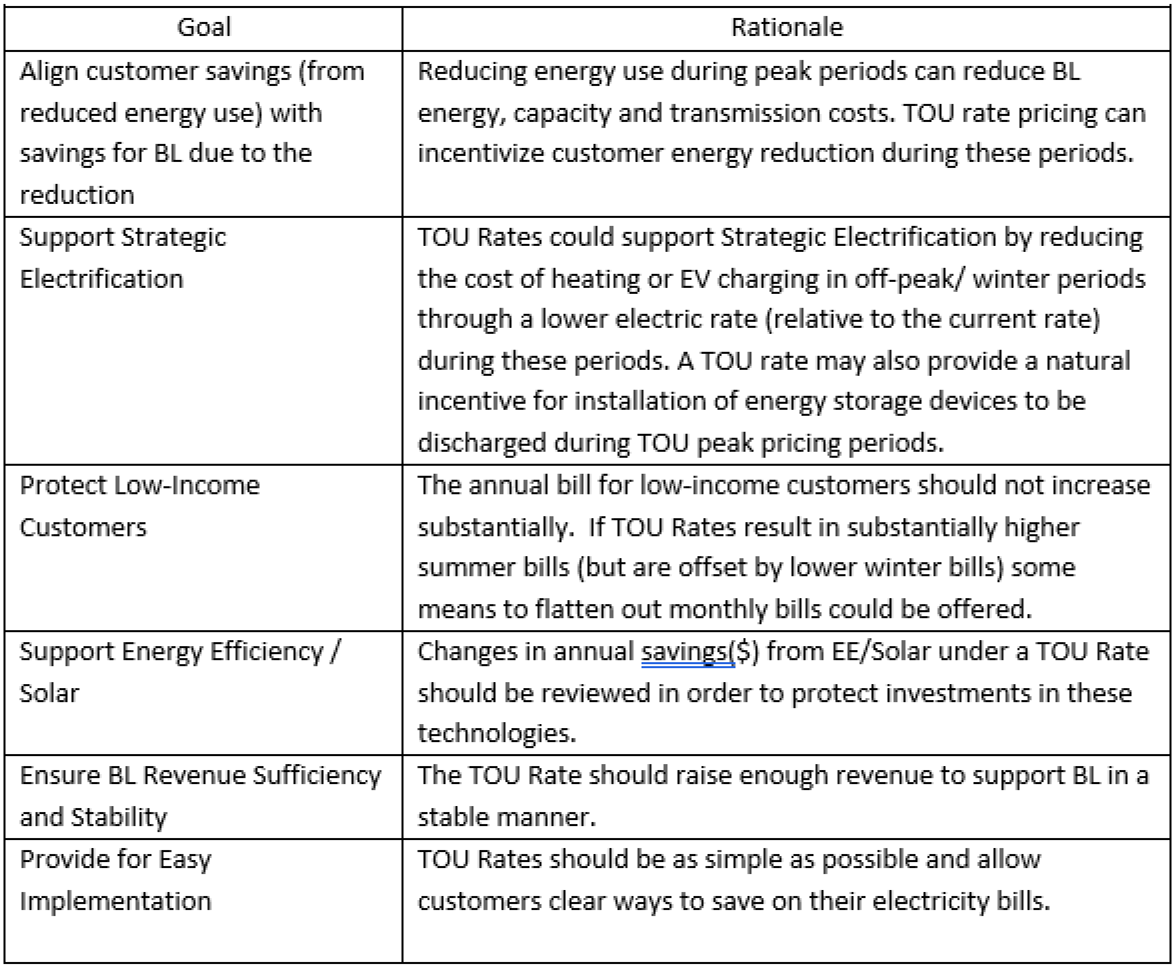
[3] "Moving Ahead with Time of Use Rates". American Public Power Association. 2020. https://www.publicpower.org/resource/moving-ahead-with-time-use-rates

[4] "PC44 Time of Use Pilots: Year One Evaluation". The Brattle Group. September 15, 2020. https://www.brattle.com/wp-content/uploads/2021/05/19973_pc44_time_of_use_pilots_-_year_one_evaluation.pdf

Table 1. Time-of-Use Rate Design Goals



Goal	Rationale
Align customer savings (from reduced energy use) with savings for BL due to the reduction	Reducing energy use during peak periods can reduce BL energy, capacity and transmission costs. TOU rate pricing can incentivize customer energy reduction during these periods.
Support Strategic Electrification	TOU Rates could support Strategic Electrification by reducing the cost of heating or EV charging in off-peak/ winter periods through a lower electric rate (relative to the current rate) during these periods. A TOU rate may also provide a natural incentive for installation of energy storage devices to be discharged during TOU peak pricing periods.
Protect Low-Income Customers	The annual bill for low-income customers should not increase substantially. If TOU Rates result in substantially higher summer bills (but are offset by lower winter bills) some means to flatten out monthly bills could be offered.
Support Energy Efficiency / Solar	Changes in annual savings($) from EE/Solar under a TOU Rate should be reviewed in order to protect investments in these technologies.
Ensure BL Revenue Sufficiency and Stability	The TOU Rate should raise enough revenue to support BL in a stable manner.
Provide for Easy Implementation	TOU Rates should be as simple as possible and allow customers clear ways to save on their electricity bills.

As the 6 goals illustrate, our reasons for embarking on a TOU program include that it might foster benefits for individual customers (bill savings), for our programs and climate initiatives (strategic electrification), for Belmont Light's annual power expenses (avoided peak supply costs), and eventually—if a pilot is successful and there is meaningful TOU adoption—for all of Belmont Light's ratepayers. Perhaps if we succeed locally, data from our pilot could be useful for other utilities in communities that are contemplating residential TOU.

d) Evaluating Rate Options

Light and LBAC commenced the rate design process in late 2019. Utility Financial Services, LLC was hired to conduct a formal rate study and multiple rate scenarios were brought to LBAC for consideration and discussion. Seven candidate rate scenarios were presented to LBAC between December 2019 and March 2020.

Table 2. Rate Scenario History describes the main rate scenarios considered and summarizes the deliberations that occurred by LBAC relative to each one.

Table 2. Rate Scenario History

Scenario #	Scenario Name	Scenario Description	Example On-to-Off Ratio	Reason Eliminated
1	10-Hour	Peak: 10 AM-10 PM, Year-Round	2.48	Peak too long; needs seasonality to better capture peak demand
2	9-Hour	Peak: 12-9 PM, Year-Round	1.25	Peak too long, on-off ratio too low
3	9-Hour with Critical Peak	Critical Peak: 3-7 PM; On-Peak 12-2 PM & 7-9 PM, Year-Round	6.59 / 2.87	Rate design too complicated; peak too long
4	9-Hour with Demand Charge	Peak 12-9 PM, Year-Round with a $0.50/kW distribution demand charge	5.46	Rate design too complicated; peak too long
5	Virtual Peaker	Peak: 5-9 PM with critical peaks based on called events, Year-Round	1.61 / 29.77	Rate design too complicated
6	Summer Peaker	Peak: 1-7 PM, June-September Only	3.61	Peak period could be expanded to target more costs
7	**6 & 4-Hour**	**Peaks: 1-7 PM June-September; 4-8 PM October-May**	**Summer- 3.44 / Non-Summer- 2.17**	**Not eliminated. Recommended scenario**

Our journey through the different rate scenarios started with designs (Scenarios 1-4) that aimed to cover the full, wide span of hours in which any of Belmont Light's peak costs have occurred in the past 10 years. (See Section 3b for more on Belmont Light's historical peaks.) While this type of design would likely perform well from a financial perspective, the resulting on-peak windows in the rate scenario were very long—nine or ten hours in duration. Discussions about these scenarios with LBAC concluded that rate scenarios with very long, daytime peak periods would not appeal to customers, especially during heating season. Additionally, the pricing ratio between the on- and off- peak charges would be too low to create a price signal that ratepayers would respond to.[5] (See Section 3b for more on peak pricing ratios.)

We also considered and ultimately dismissed several scenarios that were deemed by the group as too complicated for real-world implementation: a scenario with critical peak pricing (Scenarios 3 and 5) and a residential demand charge (Scenario 4).

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[5] These ideas mirror rate design recommendations by the Regulatory Assistance Program (RAP). In a 2020 paper, RAP found that that "Customers prefer a shorter peak period (pg. 4)" and that "…the higher the price ratio, the more likely pricing is to elicit a consumer response (pg. 5)."

Latter scenarios comprised shorter peak periods and a simpler rate design. The “Summer Peaker” scenario held up well against the six goals. Preliminary modeling of the scenario showed that it would offer meaningful savings to several customer subgroups. The rate design was simple and would have provided for easy implementation. Despite these strengths, the scenario addressed an incomplete, albeit large, portion of Belmont Light’s peak supply costs since the peak was restricted to summer months only. If Belmont Light were to opt for this scenario, we would compromise targeting 2/3rds of our annual transmission costs—an increasingly expensive budget item that will cost us a total of nearly $5 million in 2026 if we sustain our current demand patterns. Modifying the Summer Peaker scenario to include a winter-time peak would allow us to better capture our full range of peak costs, which are incurred year-round. The resulting scenario is our recommendation that we dubbed the “6 & 4 Hour Scenario”. Section 3 describes the proposed TOU Rate associated with this scenario in detail and how it fares when assessed against the six goals.

3. Proposed Residential TOU Rate: 6 & 4 Hour Scenario with Weekends & Holidays Included

a) Scenario & Rate Description

Belmont Light staff recommends that the Light Board approve a residential TOU rate scenario with the following design elements:

- **Two distinct, season-specific peak periods.** Peak hours in the summer months of June, July, August, and September would be 1:00 PM-7:00 PM. A shorter peak window of 4:00 PM-8:00 PM would apply to the remaining, non-summer months of January through May and October through December.

- **Peak hours would apply to all seven weekdays and holidays.** When thinking of standard TOU rate design, weekends and holidays might be assumed to comprise wholly off-peak hours. However, exempting weekends from the on-peak period has the impact of driving the on-to-off peak ratio to a level that, to Belmont Light and LBAC, might be intolerably high for prospective enrollees.

- **A TOU solar buyback rate.** For TOU customers, we propose to credit the applicable Generation and Transmission rates from the main TOU rate structure for the hour at which excess energy is sent back to Belmont Light’s distribution system. Our current buyback rate would remain applicable to customers on Residential Rate A.

- **The customer charge for the proposed rate should remain the same as that of Residential Rate A, currently $10.60 per month.** If the Rate A customer charge changes, the TOU customer charge should be adjusted as well.

The rate charges created by this rate design scenario are detailed in Table 3. Proposed Residential TOU Rates below.

Table 3. Proposed Residential TOU Rates[6]

Customer Charge: $10.60 per month

Non-Summer TOU Charges (Per kWh)		
Applicable January-May & October-December		
Generation		
On-Peak (4-8 PM Daily)	$	0.09513
Off-Peak	$	0.06041
Transmission		
On-Peak (4-8 PM Daily)	$	0.12686
Off-Peak	$	-
Distribution/Conservation	$	0.07745
TOTAL ENERGY WINTER		
On-Peak (4-8 PM)	**$**	**0.29944**
Off-Peak	**$**	**0.13786**
Ratio		2.17

Summer TOU Charges (Per kWh)		
Applicable June-September		
Generation		
On-Peak (1-7 PM Daily)	$	0.27819
Off-Peak	$	0.05538
Transmission		
On-Peak (1-7 PM Daily)	$	0.10152
Off-Peak	$	-
Distribution/Conservation	$	0.07745
TOTAL ENERGY SUMMER		
On-Peak (1-7 PM Daily)	**$**	**0.45716**
Off-Peak	**$**	**0.13283**
Ratio		3.44

Solar Buyback Credits (Per kWh)		
Non-Summer (January-May & October-December)		
On-Peak (4-8 PM Daily)	$	0.22199
Off-Peak	$	0.06041
Summer (June-September)		
On-Peak (1-7 PM Daily)	$	0.37971
Off-Peak	$	0.05538

Subsection “b” summarizes the rationale for the rate’s key design features. Subsection “c” provides an assessment of the rate against the six TOU goals and quantify some of benefits we expect to see from the rate.

b) Design Rationale

While the six main goals provided the framework for Belmont Light and LBAC’s rate design discussions, more detailed discussions occurred around specific design features. Here we highlight some of the philosophies and discussions that informed certain design elements of the 6 & 4 hour scenario.

Revenue Impacts

The rate was designed to be revenue neutral relative to Residential Rate A, meaning that—absent behavior change—a wholesale adoption of the rate among Rate A customers would have negligible impact on Belmont Light’s finances. Also, an average residential customer converted to TOU would not experience bill changes

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[6] There is no off-peak transmission charge in the recommended scenario as Belmont Light’s transmission costs are fully generated by on-peak consumption.

without modifying usual consumption behavior. Hence, the proposed rate is not designed to create additional revenue for Belmont Light. As a not-for-profit public power utility, our rates are always designed to reflect cost of service. Rather, in line with the TOU goals, Belmont Light seeks rate efficiency and cost avoidance through TOU. If Belmont Light is able to create long-term changes to our system-wide peak demand, all ratepayers will ultimately benefit through stable rates.

Peak Hours & Seasonality

The peak windows for the scenario were chosen after careful analysis of the hours that have driven Belmont Light's transmission and capacity costs since 2013. As shown in Figure 1 below, these peak hours tended to occur during the on-peak periods encapsulated by the rate 6 & 4 Hour scenario: 4:00-8:00 PM in all months except for the cooling months of June through September and the more erratic (yet less expensive) shoulder months of April and October. In warmer summer months, regional air-conditioning loads have driven peaks to happen as early as between 1:00 and 2:00 PM, but not later than 7:00 PM. Differentiating between summer and non-summer months allows Belmont Light to align the rate structure with our actual seasonal costs while ensuring a level of customer satisfaction by not having a long peak period year-round.

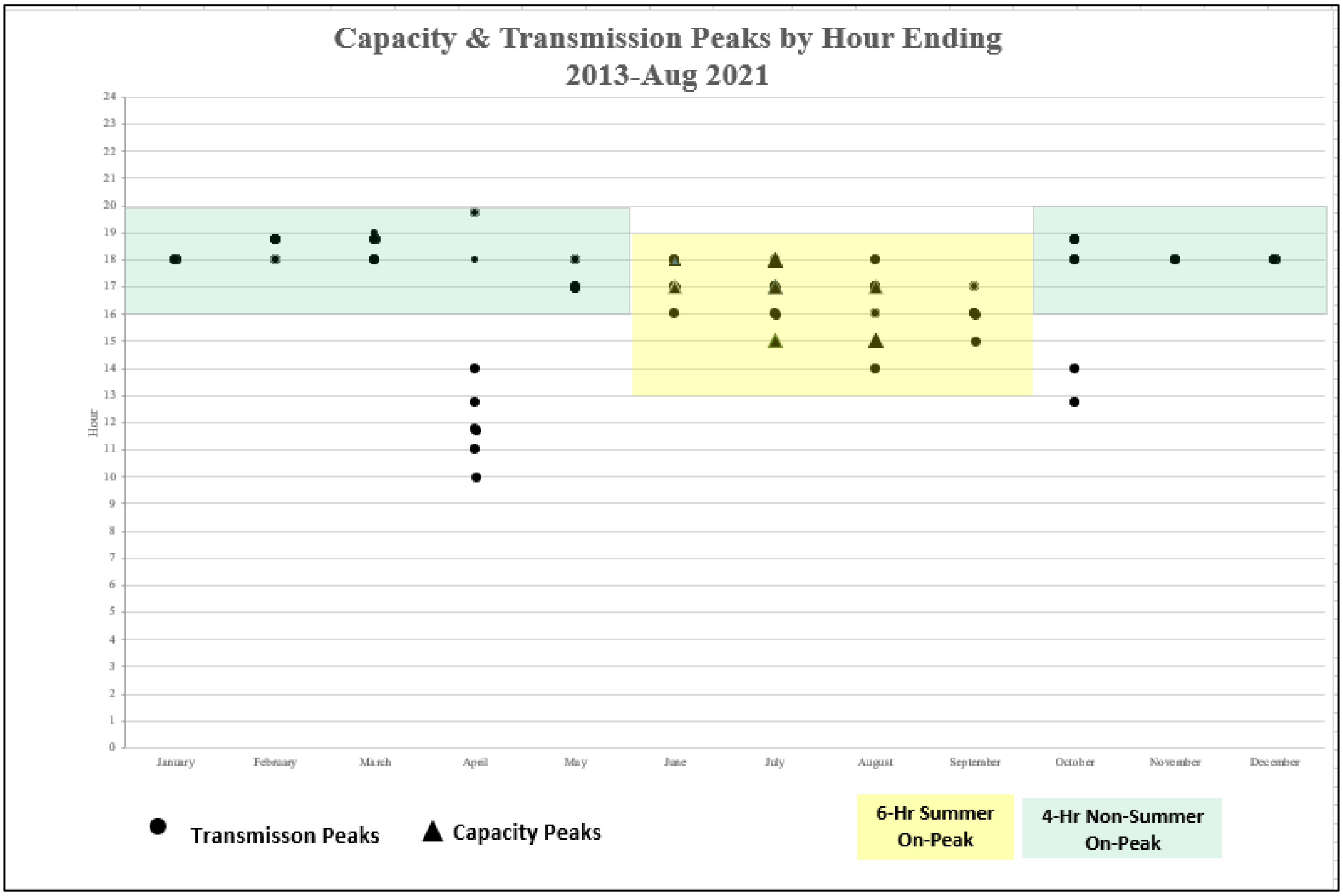
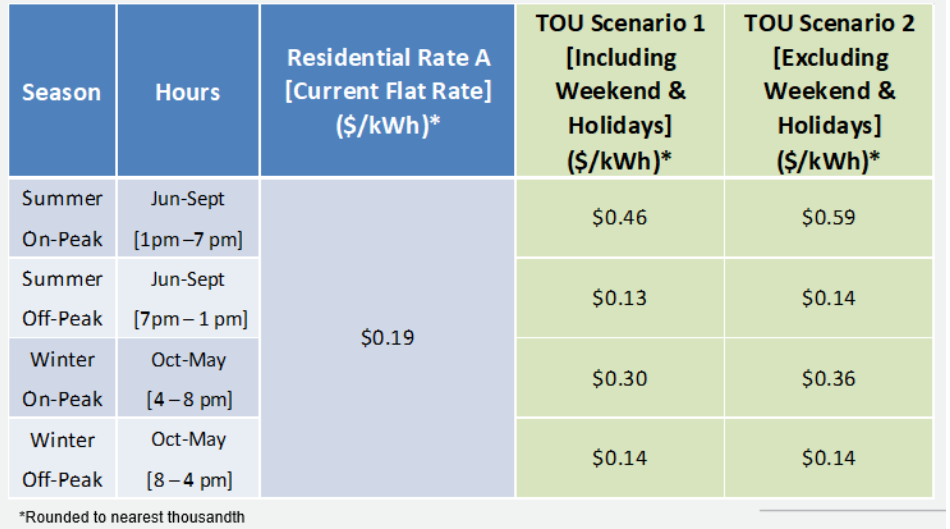


Figure 1. Historic Peak Hours and the 6 & 4 Hour Scenario

The proposed scenario is, admittedly, less likely to capture peaks in April and October. Generally, though, peak costs generated by these two months are the lowest of the year. Peak supply costs attached to summer months are much higher because of their propensity for the capacity peak—a single hour that causes millions of dollars in costs. Summer months likewise incur more transmission costs because of higher loads. For example, our budgeted transmission costs for April 2021 were $209k versus $403k for July 2021. To our group, it is a reasonable choice to chance a missed transmission peak in a lower-cost month in favor of a customer-friendly rate design.

Weekends & Holidays

Our group debated including weekends and holidays in the peak sequence or excluding them. The reasons to treat weekends and holidays as fully off-peak initially seemed obvious: 1) Belmont Light does not *typically* incur peak usage on weekends, and 2) customers familiar with the TOU concept may expect weekends to be less restrictive and entirely off-peak. However, removing weekends from the on-peak designation considerably increases the scenario's on-peak rate charges. In the proposed scenario, where the on-peak period spans all seven weekdays, the on-peak summer price is $0.46/kWh. In the scenario that treats weekends as exclusively off-peak, the on-peak summer price is $0.59/kWh, or $0.13/28% higher.



Season	Hours	Residential Rate A [Current Flat Rate] ($/kWh)*	TOU Scenario 1 [Including Weekend & Holidays] ($/kWh)*	TOU Scenario 2 [Excluding Weekend & Holidays] ($/kWh)*
Summer On-Peak	Jun-Sept [1pm –7 pm]	$0.19	$0.46	$0.59
Summer Off-Peak	Jun-Sept [7pm – 1 pm]		$0.13	$0.14
Winter On-Peak	Oct-May [4 – 8 pm]		$0.30	$0.36
Winter Off-Peak	Oct-May [8 – 4 pm]		$0.14	$0.14

*Rounded to nearest thousandth

Figure 2. Rate Comparison - Weekends Designated as On & Off Peak Versus Fully Off Peak

Although rare, weekend transmission peaks have occurred twice in the past five years, once in 2016 and once in 2020. A weekend capacity peak also nearly held as recently as 2019, when the third and fourth highest peak demands happened on a Saturday and Sunday, respectively[7]. To Belmont Light, missing a capacity peak could render a TOU program largely ineffective.

On-to-Off Peak Pricing Ratio

Several conversations with LBAC focused on finding the right ratio between on- and off-peak charges. Available literature on TOU suggests that a ratio higher than 3.0 creates a strong enough price signal to incent ratepayers to move usage off-peak[8]. Though studies also show that the higher the ratio, the more effective the rate is at stimulating off-peak consumption, our group was wary of on-peak charges (i.e. those that approached or exceeded $0.60/kWh) or ratios that might be perceived as too severe and dampen customer interest in the pilot program.

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[7] ISO-NE 2019 SMD Hourly Data accessed October 11, 2021. https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info

[8] "Time-Varying Rates in New England: Opportunities for Reform," Regulatory Assistance Program, 2020. https://www.raponline.org/knowledge-center/time-varying-rates-in-new-england-opportunities-for-reform/; "A Survey of Residential Time-of-Use (TOU) Rates," The Brattle Group, 2019. https://www.brattle.com/wp-content/uploads/2021/05/17904_a_survey_of_residential_time-of-use_tou_rates.pdf

The recommended 6 & 4 Hour scenario achieves an on-to-off peak pricing ratio of 3.44 in the summer and 2.17 in non-summer months. We feel these are suitable ratios that will induce shifting among ratepayers without creating sticker shock for potential enrollees.[9]

Solar Buyback Rate

Part of our proposal is to create a time-varied buyback rate for solar and battery customers enrolled in the pilot. The per kWh credit for the proposed buyback rate would depend on when Belmont Light receives the electricity and would be equivalent to the Generation and Transmission charges applicable under the main TOU rate. This would differ from our current buyback tariff, Rate EFR, under which Belmont Light pays a flat $0.11 for all kWh sent to Belmont Light by a solar facility irrespective of when the electricity passes from the host site to our distribution system.

Our group considered two main options regarding the buyback rate for customers with solar on TOU: leave TOU enrollees on the current Rate EFR for the buyback only or create a time-varied buyback credit based on the main TOU rate design. We are recommending the latter approach for three reasons:

1) As one of our 6 goals aims to support solar, LBAC agreed that including the buyback rate in the TOU pilot is necessary;

2) Our TOU rate design involved identifying what Belmont Light's power costs are on an hourly basis and then determining TOU charges based on those costs. Since we know the time-varied market costs we pay to ISO-NE for generation, capacity, and transmission, we are able to place a value on locally produced energy in a similar manner.

3) A main point of our TOU venture is to implement more visibly cost-based rates to help reduce customers' peak demand. We can leverage TOU to influence behavior of customers who sell us electricity as well. Solar electricity is more valuable to Belmont Light during peak times than other times of the year when our energy costs are lower. Our buyback rate should reflect this.

Implementing the proposed TOU buyback rate will likely have a small impact on the total annual amount Belmont Light pays for locally produced solar electricity each year. (i.e. The proposed TOU buyback rate will not be revenue neutral relative to Rate EFR.) If all our solar customers were on the proposed TOU rate in 2019, we would have paid an additional $21,000 for electricity from Belmont's residents and businesses. This would have increased our power supply expenses by a mere 0.1% that year. Moreover, as we are expecting to enroll a maximum of 50 solar hosts in the pilot, we expect the cost impact of the updated buyback rate to be negligible for the first year.

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[9] Designating weekends as entirely off-peak brings the summertime ratio to 4.24, which seemed too far from our 3.0 target.

Table 4

Belmont Light PV Buyback Comparison			
Results			
	System-Wide Buyback		
	2019 kWh	1,177,416	
	Scenarios	**BL Power Supply Cost**	**$ Change from Rate EFR**
	Current Rate EFR	$129,516	-
	Proposed Rate - On-Peak Includes Wk & H, Generation & Transmission Credited	$150,366	$20,850
	Alternative Rate - On-Peak Excludes Wk & H, Generation & Transmission Credited	$147,227	$17,711

Analysis also shows that if the TOU rate was effective in 2019 rather than Rate EFR, we would have paid an average price of $0.12770 per solar kWh, an increase of $0.0177 above the $0.11 we actually paid under Rate EFR.

Table 5

TOU Buyback Cost Impact				
Based on 2019 Usage, No Behavior Change				
	kWh Returned	**% Total Buyback**	**Applicable TOU Credit (per kWh)**	**BL Payout ($)**
Non-Summer On-Peak	31,441	3%	$0.22199	$ 6,980
Non-Summer Off-Peak	596,679	51%	$0.06042	$ 36,051
Summer On-Peak	237,140	20%	$0.37971	$ 90,044
Summer Off-Peak	312,156	27%	$0.05539	$ 17,290
Full Year	1,177,416		$0.12771	$ 150,366
Average Rate- Non-Summer	628,120		**$0.0685**	
Average Rate- Summer	549,296		**$0.1954**	

Modeled Customer Impacts

Much of our work on the TOU initiative focused on evaluating the potential impacts of the different scenarios on customer subgroups. LBAC Member David Beavers created a model that enabled us to compare average annual costs that customers from each group might pay under a given TOU rate scenario compared to their actual costs under Residential Rate A. We analyzed impacts for the groups based on no behavior change and also with varying levels of load shifting. The specific customer groups we evaluated were: average residential customers, top 10% kWh consumers, top 25% kWh consumers, customers on Rate LI, known electric vehicle (EV) customers, all known heat pump customers, known whole home heat pump customers, solar PV customers, and EV + solar PV customers.

Our modeling and analyses indicate that, in line with expectations, the proposed rate will have no real impact to the average customer group absent behavior change. Modeling indicates that this is true for our top-end electricity consumers as well. The rate will bring noticeable savings to all the other customer subgroups we examined. A summary of the results is in Table 6 below. We discuss these results further in Section A and provide more detailed excerpts from the model in Appendix A.

Table 6. Summary of Subgroup Impacts

Rate	Rate A	Top kWh Consumers *	Low-Income**	Electric Vehicle	Heat Pump	Whole Home Heat Pump	Solar PV	Solar & Electric Vehicle
W & H Included	0.0%	0.0%	-2.0%	-4.9%	-3.3%	-6.2%	-12.7%	-15.7%

*10th and 25th percentile residential customers by kWh consumption.
**Assumes no fixed charge for LI customers moved to TOU.

Thus, our modeling exercise purports that the proposed rate would not clearly harm any of the examined customer groups. Further, the model demonstrates that the rate would help achieve several our six goals, including those pertaining to electrification and solar. We also found that the rate would not appear to disproportionately harm our lower-income customers, though we are not recommending them for the pilot at this time as savings are not guaranteed and the proposed rate was not designed as an alternative to Rate LI.

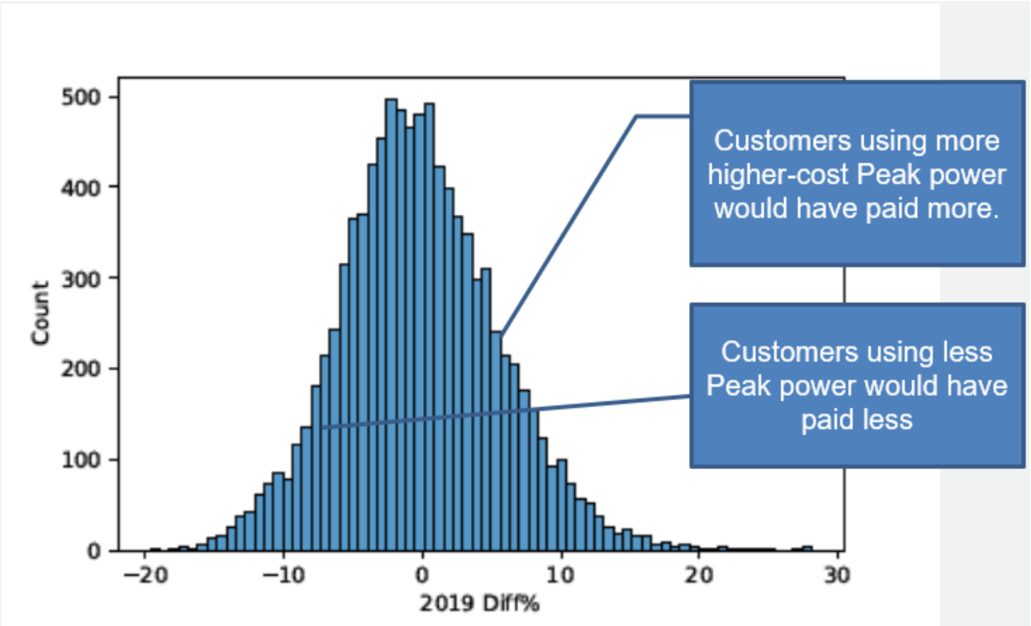


Figure 3. Impacts Histogram - Rate A Customers (source: David Beavers)

Despite indications that the recommended rate will not cause bill increases for groups of customers, it is inevitable that certain individual customers will not benefit from TOU. Figure 3 above illustrates that approximately 5% of our residential base would have endured bill increases of more than 10% if they were on the proposed rate in 2019 instead of Rate A. Customers with a historically high proportion of on-peak consumption that they cannot easily shift or reduce will see their bills increase if moved from Residential Rate A to the 6 & 4 Hour Scenario. For example, Customer A highlighted in the Figures below would have experienced bill increases of $115 in 2019 and $196 in 2020 if they were on TOU and did not adapt their consumption patterns in those two years. At this time, we are not recommending customers with load profiles like this join the TOU pilot. For comparison purposes, Customer B is an average Rate A customer that would make a good candidate for the TOU pilot. This customer would have saved $166 in 2019 and $158 in 2020 via TOU.

Figure 4. Individual Customer Results

Calculator Results - Customer A – <u>Not</u> Recommended for Pilot

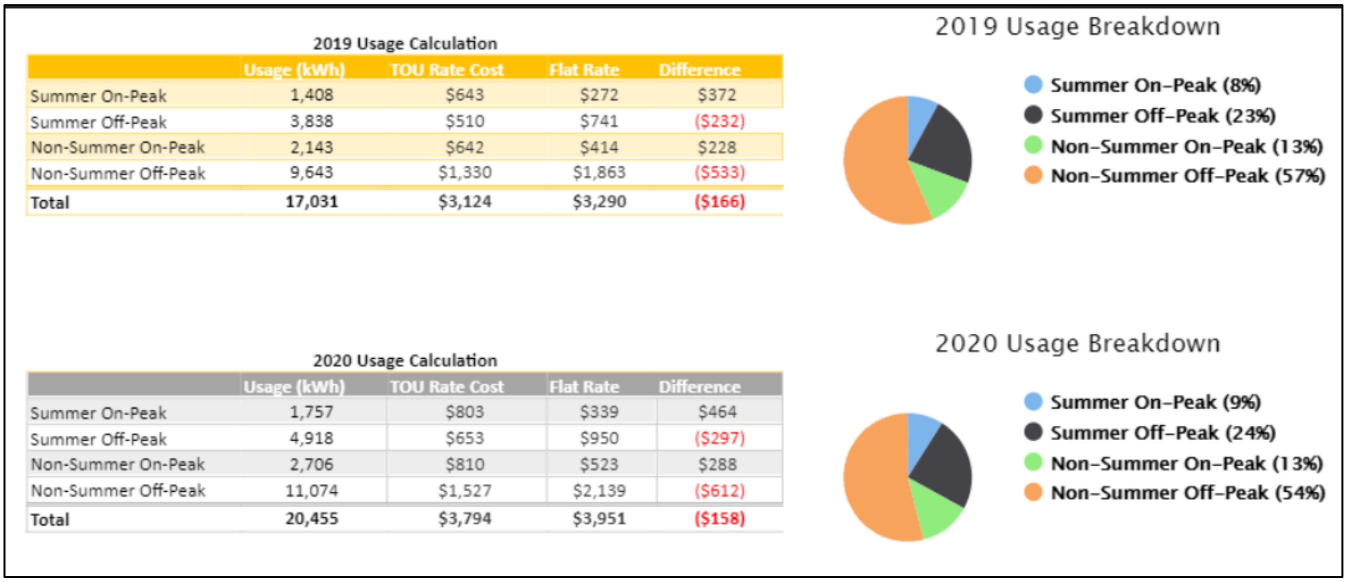
2019 Usage Calculation

	Usage (kWh)	TOU Rate Cost	Flat Rate	Difference
Summer On-Peak	1,097	$502	$212	$290
Summer Off-Peak	1,678	$223	$324	($101)
Non-Summer On-Peak	1,093	$327	$211	$116
Non-Summer Off-Peak	3,421	$472	$661	($189)
Total	**7,290**	**$1,524**	**$1,408**	**$115**

2020 Usage Calculation

	Usage (kWh)	TOU Rate Cost	Flat Rate	Difference
Summer On-Peak	1,514	$692	$292	$400
Summer Off-Peak	2,213	$294	$427	($133)
Non-Summer On-Peak	1,118	$335	$216	$119
Non-Summer Off-Peak	3,418	$471	$660	($189)
Total	**8,262**	**$1,792**	**$1,596**	**$196**

Calculator Results- Customer B- Recommended for Pilot



2019 Usage Calculation

	Usage (kWh)	TOU Rate Cost	Flat Rate	Difference
Summer On-Peak	1,408	$643	$272	$372
Summer Off-Peak	3,838	$510	$741	($232)
Non-Summer On-Peak	2,143	$642	$414	$228
Non-Summer Off-Peak	9,643	$1,330	$1,863	($533)
Total	**17,031**	**$3,124**	**$3,290**	**($166)**

2020 Usage Calculation

	Usage (kWh)	TOU Rate Cost	Flat Rate	Difference
Summer On-Peak	1,757	$803	$339	$464
Summer Off-Peak	4,918	$653	$950	($297)
Non-Summer On-Peak	2,706	$810	$523	$288
Non-Summer Off-Peak	11,074	$1,527	$2,139	($612)
Total	**20,455**	**$3,794**	**$3,951**	**($158)**

c) Customer Feedback

Starting in mid-2021, Belmont Light conducted outreach to customers to create awareness and education around TOU. Methods of outreach included multiple mass emails, messages on customer bills, and face-to-face contact at Belmont Town Day and Belmont Farmers' Markets. We formally collected customer feedback in customer emails, through our website feedback from, in-person at community events, and through two public forums. We also added calculators to our website for customers to compare their actual, individual bill costs for 2019 and 2020 to prospective costs under the proposed TOU rate.

Overall, customer response to the TOU initiative has been positive. Staff has noticed enthusiasm for TOU rates, including from many customers we have never engaged with before. Many customers were drawn to the prospect of saving money under TOU rates. Belmont Light staff has sought to ensure that each customer is aware of the real-world nature of a TOU pilot, along with the effects a switch to TOU might have on an individual's electricity costs.

Of the detracting comments and inquiries, the majority revolve around social equity and making sure that fixed-income households will not be negatively impacted by any TOU program. Limiting the participation of Rate LI customers in the pilot while we collect real customer data will, we believe, address many of these concerns. We can address other concerns via specific education and marketing campaigns showcasing the benefits of TOU rates and impacts to all customers. Overall, positive comments, ones that support and encourage adoption of TOU rates by Belmont Light, are higher in number.

The feedback form on Belmont Light's website garnered 43 responses from customers. In addition to gathering open-ended input from customers, the form provides staff with useful insights into customer demographics for TOU outreach. The results are presented in Figure 4 below.

Figure 5. Example Customer Feedback

Customers' self-rated level of knowledge on TOU:

How would you rate your level of knowledge about Time of Use Rates?	% Response
Very Knowledgeable	42%
Somewhat Knowledgeable	51%
Somewhat Unknowledgeable	7%
Very Unknowledgeable	0%

Customers' interest in TOU for themselves:

How would you rate your level of interest in Time of Use Rates for your own account?	% Response
Very Interested	77%
Need More Information	19%
Not Interested	4%

Customers' interest in joining the TOU pilot:

Would You Like to Be Considered for the TOU Pilot Program?	% Response

Yes	85%
No	4%
Need More Information	11%

And the types of distributed energy resource technologies, including electric vehicles (EVs) customers

Do you have any of these technologies at home?	Count
No Distributed Energy Resources	10
EV Only	8
ASHP Only	3
Solar Only	4
Battery Storage Only	1
Solar & ASHP	4
EV & ASHP	2
EV & Solar	7
Solar & Battery Storage	1
EV, Solar, & ASHP	1
EV, Solar, & Battery Storage	2

d) Goals Assessment & Expected Benefits

Our group believes that the proposed 6 & 4 Hour Scenario is the strongest TOU rate contender we considered. Our months of research, analysis, and discussions with MLB and customers indicate that this rate will help meet all of our formal goals while offering a high level of customer satisfaction and rate efficiency. In Table 7, we summarize how we see the rate fulfilling each of the six goals and quantify expected savings where applicable.

Approximating results from the one-year pilot is challenging since they will depend on the type of customers enrolled and how each customers responds to the TOU rate design through the duration of the pilot. Belmont Light will report actual results from the pilot when they are available.

Table 7. Goals Assessment

Goal	Expected Outcomes of Proposed 4 & 6 Hour Scenario	Assessment Method	Goal Achievable?
1. Align customer savings with savings for Belmont Light	•Average Rate A customers with 20% load shifting: -**$6/mo (-5%)**	Beavers model, customer calculators	Yes
	•Peak savings to BL: If pilot occurred in 2020, **$124 per avoided kW** during annual FCM peak, **$10.27 per avoided kW** during monthly RNS peaks (1 MW avoided peak load= ~$134k)	BL analysis	
	•High likelihood of capturing annual FCM peak and RNS peaks in 10/12 months. Chances for April and October RNS lower, but these are our cheapest months	BL analysis	
2. Support strategic electrification	•Average EV customer w/no behavior change: **-$7.50/mo (-5%)**	Beavers model & UFS	Yes
	w/ 20% load shift: **-$15/mo (-9%)**		
	•Average HP Customer w/ no behavior change: **-$5/mo (-3%)**	Beavers model & UFS	
	w/ 20% load shift: **-$11.75/mo (-8%)**		
3. Protect low-income customers	•Average LI customer w/ no behavior change: **-$1/mo (-2%)**	Beavers model	Yes*
	w/ 20% load shift: **-$5.75/mo (-10%)**		
4. Support energy efficiency and solar	•Energy efficiency: **1-3% aggregate kWh reductions**	Literature & MLP interviews	Yes
	•Energy efficiency: **3-8% aggregate kWh shift to off-peak usage**	Literature, MLP interviews, UFS	
	•Solar: Average solar customer w/buyback and no behavior change: -**$10.50/mo (-13%)**	Beavers model	
	w/buyback & 20% load shift: **-$20/mo (-17%)**		
5. Ensure BL revenue sufficiency and stability	•Rate designed to be revenue neutral	UFS	Yes
	•Expect pilot to cost some money if only obvious "winners" are enrolled. Enrollee cap will help address this	Literature	
	•Minimal budget increase for BL from buyback rate change	Beavers & BL analysis	
6. Provide for easy implementation	•Rate structure compatible with BL's meter and billing systems	BL	Yes
	•Rate design not too complicated for ratepayers	LBAC, customer feedback forms, 2 public forums	

*Though modeling suggests the proposed rate would not harm an average Rate LI customer, we are not recommending that Rate LI customers convert to TOU at this time.

4. Pilot Program

We plan to run the TOU pilot from January 1, 2022 through December 31, 2022. This time frame gives Belmont Light data from one full year of usage from the participating customers and will show how customers adapt to the peak periods during the various seasons.

Belmont Light will require interested residents to fill out an application to enroll in the TOU pilot. The information included in the application will allow Belmont Light to verify customer information against our records. Beyond basic account and contact information, Belmont Light is asking for customers to supply information about their homes and how they utilize electricity, such as heating source and whether they have installed central air, air source heat pumps, or solar. These factors will help Belmont Light analyze electric load before, during, and after the pilot.

During the pilot program, participants will have access to Belmont Light staff to discuss their bills in detail. Using customer-accessible tools such as SmartHub and internal tools via the MDM, Belmont Light staff will help customers talk through their electric bill and see if there are changes that can be made to optimize their usage on the TOU rate. It is the hope of Belmont Light that we will be able to help customers achieve savings and encourage better habits to help their own energy use and the energy use of Belmont.

While researching TOU offerings of other MLPs, Belmont Light gathered information on pilot programs. Many of the MLPs that we spoke to or reviewed enrolled around 1% of their residential customer base in their pilots.[10] In relating these findings to Belmont Light, we considered what number of participants would provide quality data, while also remaining realistic about what level of enrollees would be manageable administratively. With these concerns in mind, Belmont Light developed a target of 150 customers total enrollees, which would represent approximately 1.5% of our residential customers.

To ensure that this pilot properly evaluates all of the six goals, we also developed targets for specific sub-groups. These groups include customers that have no distributed energy resources (DERs), such as air source heat pumps, electric vehicles, solar and battery storage, and customers that have them. The full breakdown of the categories is supplied in Table 8. The plans described here are not st. Depending on customer interest, final pilot enrollment may change.

Table 8. Planned Pilot Enrollment by Subgroup

Customer Group	Number of Customers	Percent of Pilot Customers
No DERs	45	30%
Air Source Heat Pump (ASHP)	20	13%
Electric Vehicle (EV)	30	20%
Solar	30	20%
ASHP & EV	5	3%
ASHP & Solar	6	4%
EV & Solar	6	4%
ASHP, EV, & Solar	8	5%
Total	**150**	**100%**

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[10] Fort Collins, CO 3 enrolled 3.15% of their residential customer base. This was higher-than-expected enrollment and, according to staff, a smaller pilot would still have yielded useful results.

APPENDIX A. Modeled Customer Impacts

Table 9. Summary of Impacts to Average Customer Groups - Recommended Rate & Runner-Up Rate

Monthly Bill Impacts- No Change in Consumption, 2019 Distribution Charges														
Rate Scenario	All Residential Customers (ARC)		Low Income Customers (LI)		Customers with EV (EV)		Customers With Heat Pumps (HP)		Customers With Whole-Home Heat Pumps (WHHP)		Customers With PV (PV)		Customers With EV & PV (EVPV)	
	Cost	$ Change	Cost	$ Change	Cost	$ Change	Cost	$ Change	Cost	$ Change	Cost	$ Change	Cost	$ Change
Current Rate	$112.75		$55.98		$162.64		$145.94		$264.52		$82.98		$115.60	
Recommendation: Weekends & Holidays Included	$112.73	-$0.03	$54.87	-$1.11	$155.18	-$7.46	$141.07	-$4.87	$247.99	-$16.53	$72.42	-$10.56	$97.50	-$18.11
Weekends & Holidays Excluded	$112.41	-$0.34	$54.85	-$1.13	$154.61	-$8.03	$141.24	-$4.70	$248.94	-$15.58	$72.28	-$10.70	$96.90	-$18.70

Table 10. Impacts to Average Residential Customer Group

	Recommended Rate - Peak Includes Weekends & Holidays				
	Energy Usage (kWh)	Current Rate (Cust. Cost)	1A Customer Cost	1A Change (%)	1A Change $/month
Winter On-Peak	862	$181	$272	51%	$11.43
Winter Off-Peak	3,173	$684	$508	-26%	-$22.01
Winter Subtotal	4,035	$865	$780	-10%	-$10.59
Summer On-Peak	690	$144	$326	126%	$45.52
Summer Off-Peak	1,614	$344	$246	-28%	-$24.43
Summer Subtotal	2,305	$488	$572	17%	$21.09
Annual Total	6,339	$1,353	$1,353	0%	-$0.03

With Rate Change	
Winter Cost Change	-$85
Summer Cost Change	$84
Annual	$0

Bill Reduction With Load Shifting: Scenario 1A - Peak Includes Weekends & Holidays

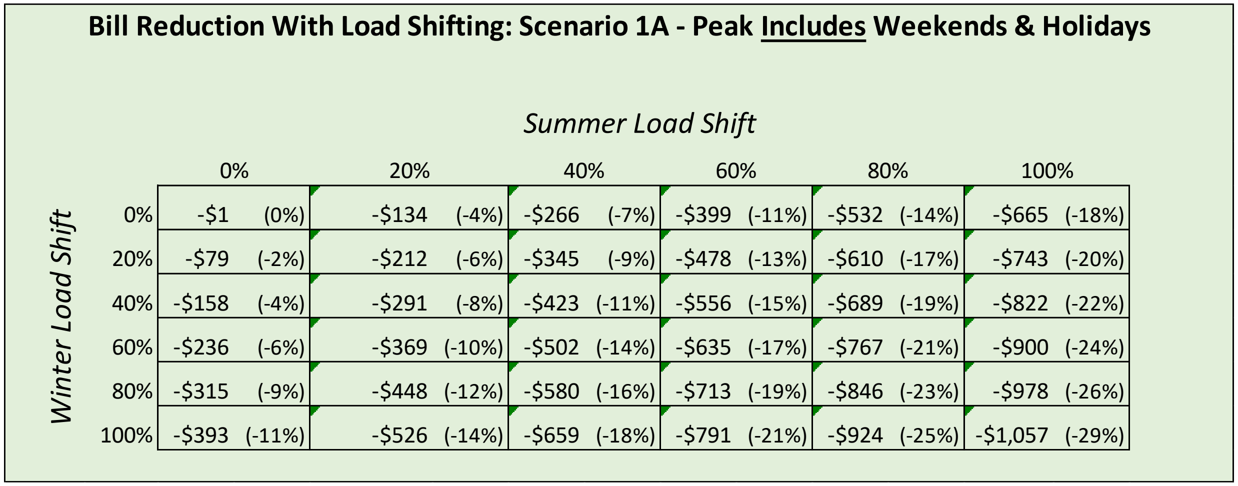
Summer Load Shift

Winter Load Shift		0%	20%	40%	60%	80%	100%
	0%	$0 (0%)	-$45 (-3%)	-$90 (-7%)	-$135 (-10%)	-$179 (-13%)	-$224 (-17%)
	20%	-$28 (-2%)	-$73 (-5%)	-$118 (-9%)	-$163 (-12%)	-$207 (-15%)	-$252 (-19%)
	40%	-$56 (-4%)	-$101 (-7%)	-$146 (-11%)	-$190 (-14%)	-$235 (-17%)	-$280 (-21%)
	60%	-$84 (-6%)	-$129 (-10%)	-$173 (-13%)	-$218 (-16%)	-$263 (-19%)	-$308 (-23%)
	80%	-$112 (-8%)	-$157 (-12%)	-$201 (-15%)	-$246 (-18%)	-$291 (-21%)	-$336 (-25%)
	100%	-$140 (-10%)	-$184 (-14%)	-$229 (-17%)	-$274 (-20%)	-$319 (-24%)	-$363 (-27%)

Table 11. Impacts to Top 10% Residential Customers by KWH Consumption

	Recommended Rate - Peak Includes Weekends & Holidays				
	Energy Usage (kWh)	Current Rate (Cust. Cost)	1A Customer Cost	1A Change (%)	1A Change $/month
Winter On-Peak	2,428	$484	$741	53%	$32.19
Winter Off-Peak	9,498	$1,907	$1,380	-28%	-$65.90
Winter Subtotal	11,926	$2,391	$2,121	-11%	-$33.71
Summer On-Peak	2,046	$406	$946	133%	$134.94
Summer Off-Peak	4,478	$898	$627	-30%	-$67.77
Summer Subtotal	6,524	$1,304	$1,573	21%	$67.17
Annual Total	18,450	$3,695	$3,694	0%	-$0.08

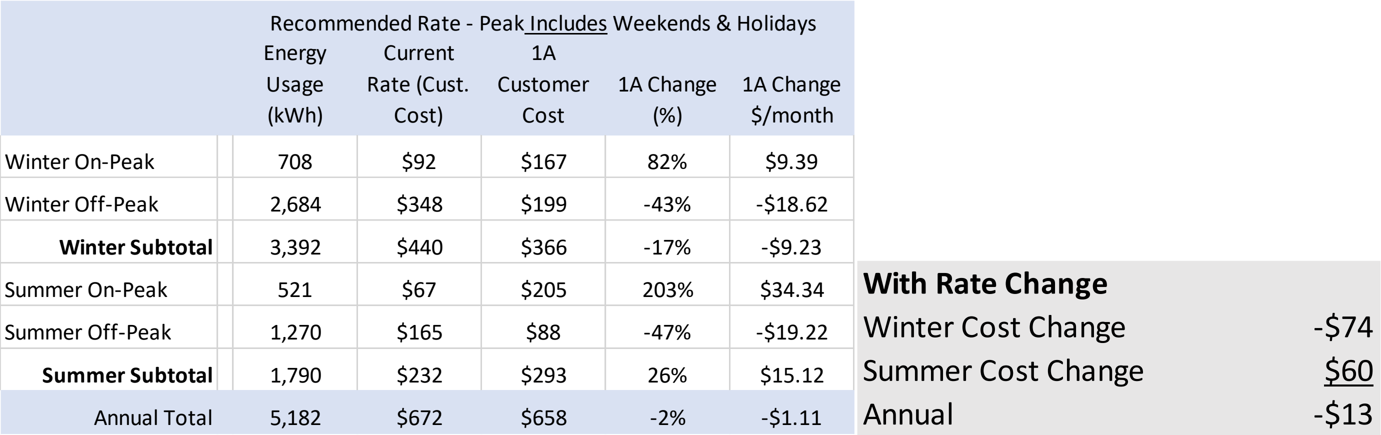
With Rate Change	
Winter Cost Change	-$270
Summer Cost Change	$269
Annual	-$1



Bill Reduction With Load Shifting: Scenario 1A - Peak Includes Weekends & Holidays

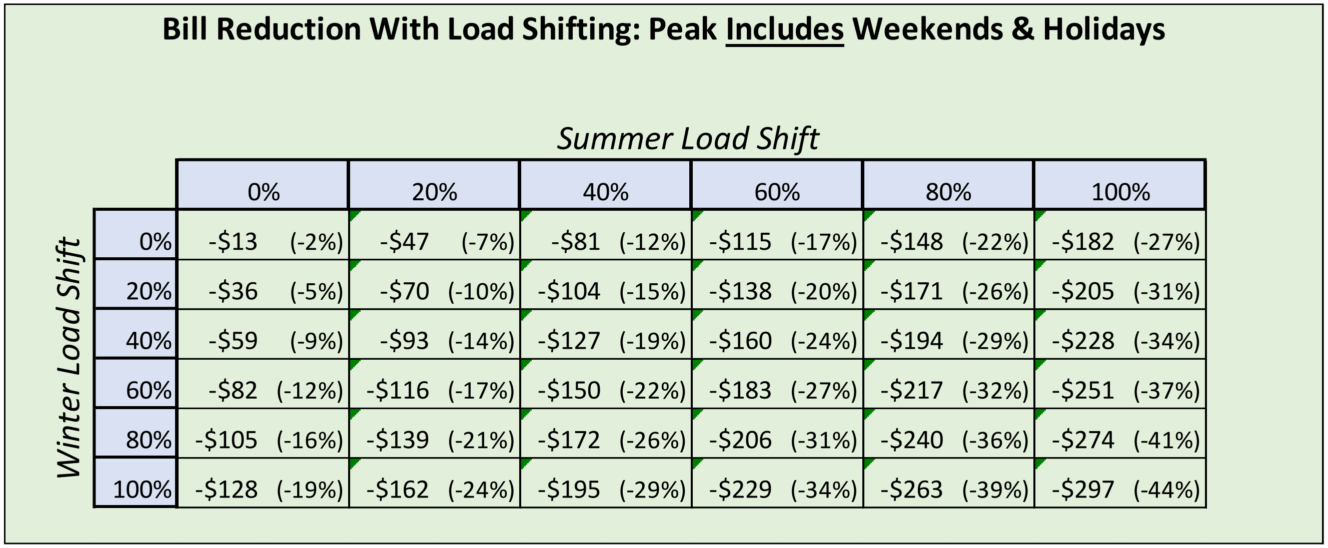
		Summer Load Shift					
		0%	20%	40%	60%	80%	100%
Winter Load Shift	0%	-$1 (0%)	-$134 (-4%)	-$266 (-7%)	-$399 (-11%)	-$532 (-14%)	-$665 (-18%)
	20%	-$79 (-2%)	-$212 (-6%)	-$345 (-9%)	-$478 (-13%)	-$610 (-17%)	-$743 (-20%)
	40%	-$158 (-4%)	-$291 (-8%)	-$423 (-11%)	-$556 (-15%)	-$689 (-19%)	-$822 (-22%)
	60%	-$236 (-6%)	-$369 (-10%)	-$502 (-14%)	-$635 (-17%)	-$767 (-21%)	-$900 (-24%)
	80%	-$315 (-9%)	-$448 (-12%)	-$580 (-16%)	-$713 (-19%)	-$846 (-23%)	-$978 (-26%)
	100%	-$393 (-11%)	-$526 (-14%)	-$659 (-18%)	-$791 (-21%)	-$924 (-25%)	-$1,057 (-29%)

Table 12. Estimated Impacts to Average Low-Income Rate Group



	Recommended Rate - Peak Includes Weekends & Holidays				
	Energy Usage (kWh)	Current Rate (Cust. Cost)	1A Customer Cost	1A Change (%)	1A Change $/month
Winter On-Peak	708	$92	$167	82%	$9.39
Winter Off-Peak	2,684	$348	$199	-43%	-$18.62
Winter Subtotal	3,392	$440	$366	-17%	-$9.23
Summer On-Peak	521	$67	$205	203%	$34.34
Summer Off-Peak	1,270	$165	$88	-47%	-$19.22
Summer Subtotal	1,790	$232	$293	26%	$15.12
Annual Total	5,182	$672	$658	-2%	-$1.11

With Rate Change	
Winter Cost Change	-$74
Summer Cost Change	$60
Annual	-$13



Bill Reduction With Load Shifting: Peak Includes Weekends & Holidays

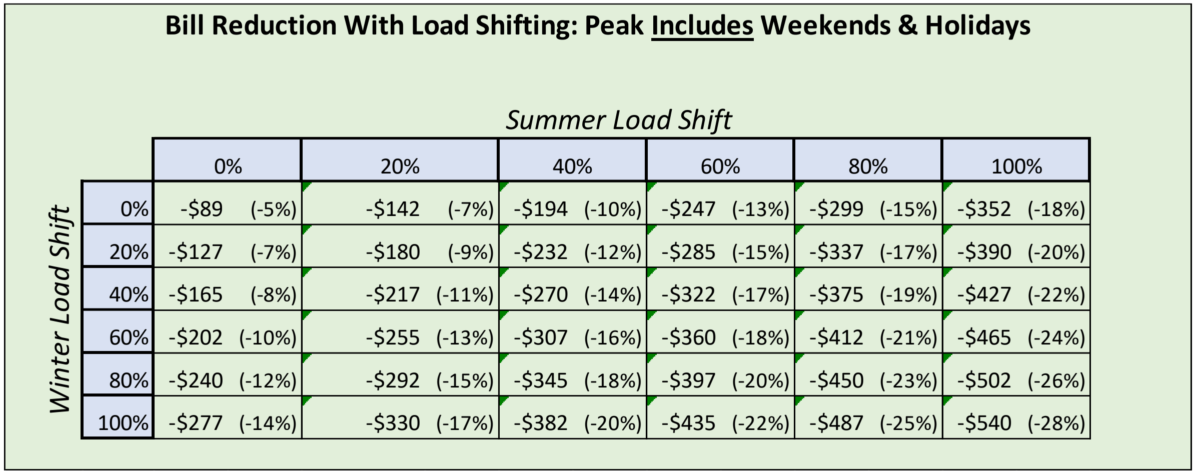
Summer Load Shift

Winter Load Shift	0%	20%	40%	60%	80%	100%
0%	-$13 (-2%)	-$47 (-7%)	-$81 (-12%)	-$115 (-17%)	-$148 (-22%)	-$182 (-27%)
20%	-$36 (-5%)	-$70 (-10%)	-$104 (-15%)	-$138 (-20%)	-$171 (-26%)	-$205 (-31%)
40%	-$59 (-9%)	-$93 (-14%)	-$127 (-19%)	-$160 (-24%)	-$194 (-29%)	-$228 (-34%)
60%	-$82 (-12%)	-$116 (-17%)	-$150 (-22%)	-$183 (-27%)	-$217 (-32%)	-$251 (-37%)
80%	-$105 (-16%)	-$139 (-21%)	-$172 (-26%)	-$206 (-31%)	-$240 (-36%)	-$274 (-41%)
100%	-$128 (-19%)	-$162 (-24%)	-$195 (-29%)	-$229 (-34%)	-$263 (-39%)	-$297 (-44%)

Table 13. Estimated Impacts for Average EV Customer Group

	Recommended Rate - Peak Includes Weekends & Holidays				
	Energy Usage (kWh)	Current Rate (Cust. Cost)	1A Customer Cost	1A Change (%)	1A Change $/month
Winter On-Peak	1,163	$239	$362	52%	$15.42
Winter Off-Peak	5,054	$1,048	$767	-27%	-$35.07
Winter Subtotal	6,217	$1,287	$1,130	-12%	-$19.65
Summer On-Peak	809	$167	$381	128%	$53.38
Summer Off-Peak	2,409	$498	$352	-29%	-$36.45
Summer Subtotal	3,218	$665	$732	10%	$16.93
Annual Total	9,435	$1,952	$1,862	-5%	-$7.46

With Rate Change	
Winter Cost Change	-$157
Summer Cost Change	$68
Annual	-$89



Bill Reduction With Load Shifting: Peak Includes Weekends & Holidays

		Summer Load Shift					
		0%	20%	40%	60%	80%	100%
Winter Load Shift	0%	-$89 (-5%)	-$142 (-7%)	-$194 (-10%)	-$247 (-13%)	-$299 (-15%)	-$352 (-18%)
	20%	-$127 (-7%)	-$180 (-9%)	-$232 (-12%)	-$285 (-15%)	-$337 (-17%)	-$390 (-20%)
	40%	-$165 (-8%)	-$217 (-11%)	-$270 (-14%)	-$322 (-17%)	-$375 (-19%)	-$427 (-22%)
	60%	-$202 (-10%)	-$255 (-13%)	-$307 (-16%)	-$360 (-18%)	-$412 (-21%)	-$465 (-24%)
	80%	-$240 (-12%)	-$292 (-15%)	-$345 (-18%)	-$397 (-20%)	-$450 (-23%)	-$502 (-26%)
	100%	-$277 (-14%)	-$330 (-17%)	-$382 (-20%)	-$435 (-22%)	-$487 (-25%)	-$540 (-28%)

Table 14. Estimated Impacts for Average Heat Pump Group (Includes Partial & Whole Home Systems)

	Recommended Rate - Peak Includes Weekends & Holidays				
	Energy Usage (kWh)	Current Rate (Cust. Cost)	1A Customer Cost	1A Change (%)	1A Change $/month
Winter On-Peak	1,209	$248	$376	52%	$16.03
Winter Off-Peak	4,764	$992	$727	-27%	-$33.05
Winter Subtotal	5,973	$1,240	$1,104	-11%	-$17.02
Summer On-Peak	692	$145	$327	126%	$45.67
Summer Off-Peak	1,733	$367	$262	-29%	-$26.23
Summer Subtotal	2,425	$511	$589	15%	$19.44
Annual Total	8,399	$1,751	$1,693	-3%	-$4.87

With Rate Change	
Winter Cost Change	-$136
Summer Cost Change	$78
Annual	-$58

Bill Reduction With Load Shifting: Peak Includes Weekends & Holidays

	Summer Load Shift					
Winter Load Shift	0%	20%	40%	60%	80%	100%
0%	-$58 (-3%)	-$103 (-6%)	-$148 (-8%)	-$193 (-11%)	-$238 (-14%)	-$283 (-16%)
20%	-$97 (-6%)	-$142 (-8%)	-$187 (-11%)	-$232 (-13%)	-$277 (-16%)	-$322 (-18%)
40%	-$137 (-8%)	-$181 (-10%)	-$226 (-13%)	-$271 (-15%)	-$316 (-18%)	-$361 (-21%)
60%	-$176 (-10%)	-$221 (-13%)	-$265 (-15%)	-$310 (-18%)	-$355 (-20%)	-$400 (-23%)
80%	-$215 (-12%)	-$260 (-15%)	-$305 (-17%)	-$349 (-20%)	-$394 (-23%)	-$439 (-25%)
100%	-$254 (-14%)	-$299 (-17%)	-$344 (-20%)	-$389 (-22%)	-$433 (-25%)	-$478 (-27%)

Table 15. Estimated Impacts to Average Whole Home Heat Pump Group

	Recommended Rate - Peak Includes Weekends & Holidays				
	Energy Usage (kWh)	Current Rate (Cust. Cost)	1A Customer Cost	1A Change (%)	1A Change $/month
Winter On-Peak	2,319	$463	$709	53%	$30.75
Winter Off-Peak	10,094	$2,023	$1,462	-28%	-$70.03
Winter Subtotal	12,413	$2,485	$2,171	-13%	-$39.28
Summer On-Peak	981	$200	$459	129%	$64.72
Summer Off-Peak	2,362	$489	$346	-29%	-$35.75
Summer Subtotal	3,344	$689	$805	17%	$28.97
Annual Total	15,757	$3,174	$2,976	-6%	-$16.53

With Rate Change	
Winter Cost Change	-$314
Summer Cost Change	$116
Annual	-$198

Bill Reduction With Load Shifting: Peak Includes Weekends & Holidays

Summer Load Shift

Winter Load Shift	0%	20%	40%	60%	80%	100%
0%	-$198 (-6%)	-$262 (-8%)	-$326 (-10%)	-$389 (-12%)	-$453 (-14%)	-$517 (-16%)
20%	-$273 (-9%)	-$337 (-11%)	-$401 (-13%)	-$464 (-15%)	-$528 (-17%)	-$592 (-19%)
40%	-$348 (-11%)	-$412 (-13%)	-$476 (-15%)	-$539 (-17%)	-$603 (-19%)	-$667 (-21%)
60%	-$423 (-13%)	-$487 (-15%)	-$551 (-17%)	-$614 (-19%)	-$678 (-21%)	-$742 (-23%)
80%	-$498 (-16%)	-$562 (-18%)	-$625 (-20%)	-$689 (-22%)	-$753 (-24%)	-$816 (-26%)
100%	-$573 (-18%)	-$637 (-20%)	-$700 (-22%)	-$764 (-24%)	-$828 (-26%)	-$891 (-28%)

Table 16. Estimated Impacts for Average Solar PV Group

	Recommended Rate - Peak Includes Weekends & Holidays									
	Energy Usage (kWh)	BuyBack Energy (kWh)	Current Rate (Cust. Cost)	Current BuyBack (Cust Value)	Current Total	1A Customer Cost	1A BuyBack	1A Total	1A Change (%)	1A Change $/month
Winter On-Peak	1,064	98	$220	$11	$209	$333	$22	$311	49%	$12.75
Winter Off-Peak	3,504	1,859	$748	$204	$544	$554	$111	$442	-19%	-$12.67
Winter Subtotal	4,568	1,957	$968	$215	$753	$887	$133	$754	0%	$0.07
Summer On-Peak	431	739	$94	$81	$13	$207	$280	-$73	-676%	-$21.32
Summer Off-Peak	1,579	972	$337	$107	$230	$242	$53	$188	-18%	-$10.50
Summer Subtotal	2,010	1,711	$431	$188	$243	$449	$334	$116	-52%	-$31.82
Annual Total	6,578	3,668	$1,399	$403	$996	$1,336	$467	$869	-13%	-$10.56

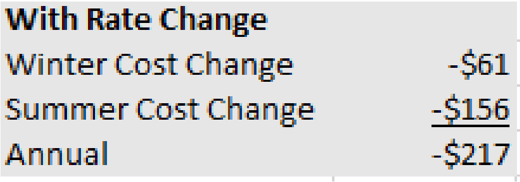
With Rate Change	
Winter Cost Change	$1
Summer Cost Change	-$127
Annual	-$127

Bill Reduction With Load Shifting: Peak <u>Includes</u> Weekends & Holidays

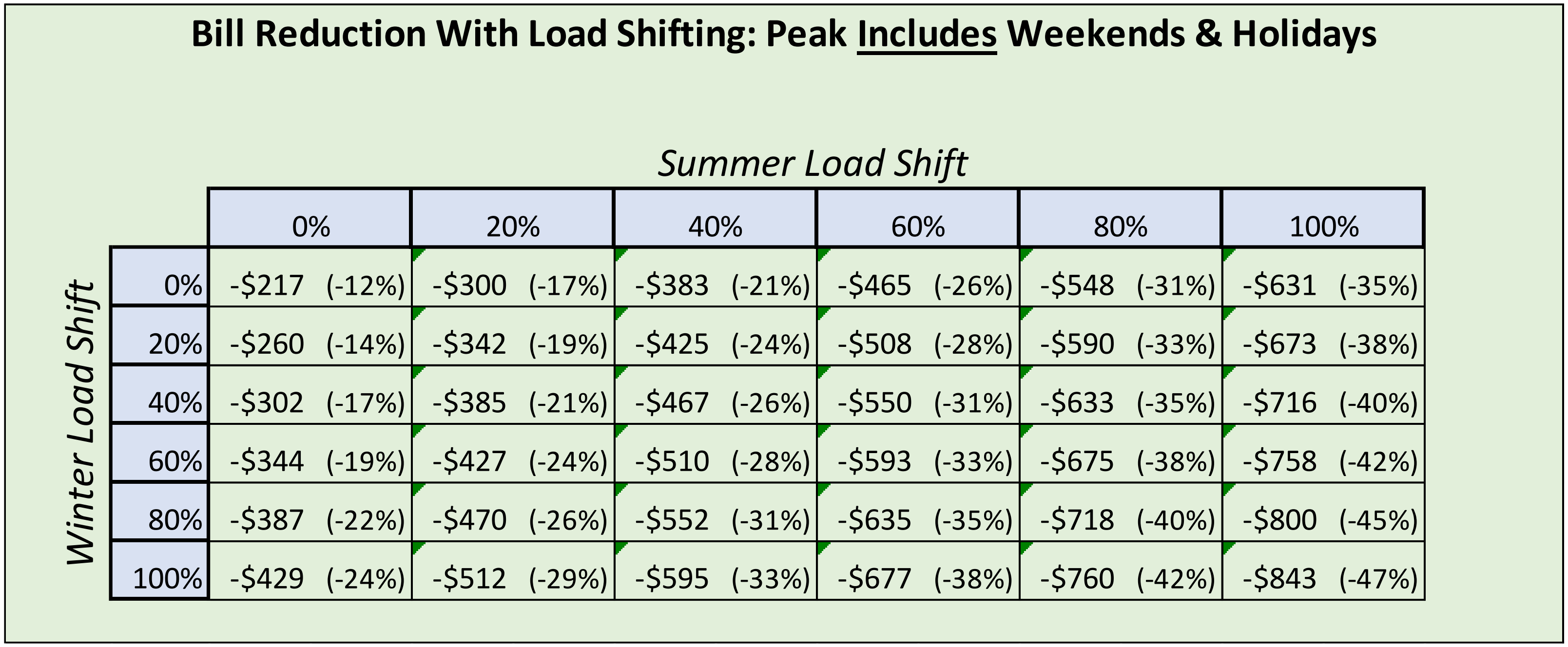
		Summer Load Shift					
		0%	20%	40%	60%	80%	100%
Winter Load Shift	0%	-$127 (-9%)	-$203 (-14%)	-$278 (-20%)	-$354 (-25%)	-$430 (-31%)	-$506 (-36%)
	20%	-$164 (-12%)	-$240 (-17%)	-$316 (-23%)	-$392 (-28%)	-$468 (-33%)	-$544 (-39%)
	40%	-$202 (-14%)	-$278 (-20%)	-$354 (-25%)	-$429 (-31%)	-$505 (-36%)	-$581 (-42%)
	60%	-$239 (-17%)	-$315 (-23%)	-$391 (-28%)	-$467 (-33%)	-$543 (-39%)	-$619 (-44%)
	80%	-$277 (-20%)	-$353 (-25%)	-$429 (-31%)	-$505 (-36%)	-$580 (-41%)	-$656 (-47%)
	100%	-$315 (-22%)	-$390 (-28%)	-$466 (-33%)	-$542 (-39%)	-$618 (-44%)	-$694 (-50%)

Table 17. Estimated Impacts for Average EV + Solar PV Group

	Recommended Rate - Peak <u>Includes</u> Weekends & Holidays									
	Energy Usage (kWh)	BuyBack Energy (kWh)	Current Rate (Cust. Cost)	Current BuyBack (Cust Value)	Current Total	1A Customer Cost	1A BuyBack	1A Total	1A Change (%)	1A Change $/month
Winter On-Peak	1,208	104	$248	$11	$236	$376	$23	$353	49%	$14.58
Winter Off-Peak	4,860	1,831	$1,010	$201	$809	$741	$110	$631	-22%	-$22.26
Winter Subtotal	6,068	1,935	$1,258	$213	$1,045	$1,117	$133	$984	-6%	-$7.68
Summer On-Peak	485	789	$104	$87	$18	$233	$299	-$67	-479%	-$21.12
Summer Off-Peak	2,067	975	$431	$107	$324	$306	$54	$253	-22%	-$17.84
Summer Subtotal	2,552	1,765	$536	$194	$342	$539	$353	$186	-46%	-$38.96
Annual Total	8,620	3,700	$1,794	$407	$1,387	$1,656	$486	$1,170	-16%	-$18.11



With Rate Change	
Winter Cost Change	-$61
Summer Cost Change	-$156
Annual	-$217



Bill Reduction With Load Shifting: Peak Includes Weekends & Holidays

		Summer Load Shift					
		0%	20%	40%	60%	80%	100%
Winter Load Shift	0%	-$217 (-12%)	-$300 (-17%)	-$383 (-21%)	-$465 (-26%)	-$548 (-31%)	-$631 (-35%)
	20%	-$260 (-14%)	-$342 (-19%)	-$425 (-24%)	-$508 (-28%)	-$590 (-33%)	-$673 (-38%)
	40%	-$302 (-17%)	-$385 (-21%)	-$467 (-26%)	-$550 (-31%)	-$633 (-35%)	-$716 (-40%)
	60%	-$344 (-19%)	-$427 (-24%)	-$510 (-28%)	-$593 (-33%)	-$675 (-38%)	-$758 (-42%)
	80%	-$387 (-22%)	-$470 (-26%)	-$552 (-31%)	-$635 (-35%)	-$718 (-40%)	-$800 (-45%)
	100%	-$429 (-24%)	-$512 (-29%)	-$595 (-33%)	-$677 (-38%)	-$760 (-42%)	-$843 (-47%)