Implications of Rate Design for the Customer-Economics of Behind-the-Meter Storage

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Major factors motivating retail rate reforms

- Utilities are deploying advanced metering infrastructure (AMI)
- Distributed energy resource (DER) cost declines and technological innovations
- Utilities are reaching net energy metering (NEM) caps
- Concerns about utility fixed cost recovery and revenue sufficiency
- Desire for fair and equitable compensation for DER electricity generation
- Variable renewable energy (VRE) integration issues (e.g., over-generation and net load shape impacts)

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Recent retail rate design trends

Increased pursuit of residential time-varying pricing

- Default (Sacramento Municipal Utility District, CA IOUs)
- Voluntary (Oklahoma Gas & Electric)

Introduction of energy pricing and programs for midday load building

- Matinee pricing (California investor-owned utilities)
- Reverse demand response pilot (Arizona Public Service)

Increased application of residential three-part rates

- All residential customers (Arizona Public Service)
- DG-customers only (Salt River Project)

Reforms to DG compensation

- Net billing (New York Value of Distributed Energy, VDER, Michigan)
- Buy-all/sell-all rates (Minnesota value-of-solar tariff)

Development of electric-vehicle specific rates

- Private charging - “whole home” (Georgia Power)
- Private/public charging – EV only (Austin Energy)
- Multi-unit dwelling charging – EV only (San Diego Gas & Electric)

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Rate design and the customer-economics of BTM storage: An essential piece of the rate reform puzzle

- Electricity bill savings from behind-the-meter (BTM) storage are intrinsically linked to retail electricity rate design
- Proposed changes in rate design → impact the customer economics of storage will be essential
- Previous work (e.g., McKinsey & Co. 2018, NREL 2017) has focused primarily on the nominal $/kW demand charge rate as the key driver for bill savings from BTM storage

  → Other aspects of demand charge design + details of time-varying energy rates and net billing rates for PV customers may also be critical to BTM storage economics

- This work aims to **fill in these gaps** and **provide additional insights** into which rate design elements are most important to the customer-economics and market potential of BTM storage

Project overview

This analysis explores how the details of retail electricity rate design can impact customer bill savings from behind-the-meter (BTM) storage

Scope

- Focus is on the *customer*-economics
- Addresses just one aspect of the customer-economics: utility bill savings

Approach: Compute/compare utility bill savings from BTM storage across a range of rate structures and load shapes

Key rate design features impacting bill savings from BTM storage

Demand-charge savings depend on:

- Size of the demand charge rate ($/kW)
- Non-coincident vs. peak-period demand charges
- Timing and duration of peak period
- Averaging interval for measuring billing demand
- Seasonal variation in demand charge rates
- Ratchets

The analysis characterizes the *relative significance* and *manner* in which these rate design features impact BTM storage economics

Energy-charge arbitrage savings depend on:

- Price differential between high/low price periods
- Daily/monthly structure of price variability
- Duration of high/low price periods

Vary among: Time-of-Use (TOU), Critical Peak Pricing (CPP), Real-Time Pricing (RTP), and Net Billing rate structures

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Load data for demand charge analysis

- Demand charge analysis → commercial customers
- 5-minute interval load data (Enel X, formerly EnerNOC)
- Selected three representative customer loads: (1) a shopping center, (2) a shopping center with a PV system, and (3) a manufacturing plant—see next slide
  - Solar profile constructed from the National Renewable Energy Laboratory (NREL)’s National Solar Resource Database converted to solar generation data using NREL’s System Advisor Model
  - PV system sized to generate 50% of the building’s annual energy consumption

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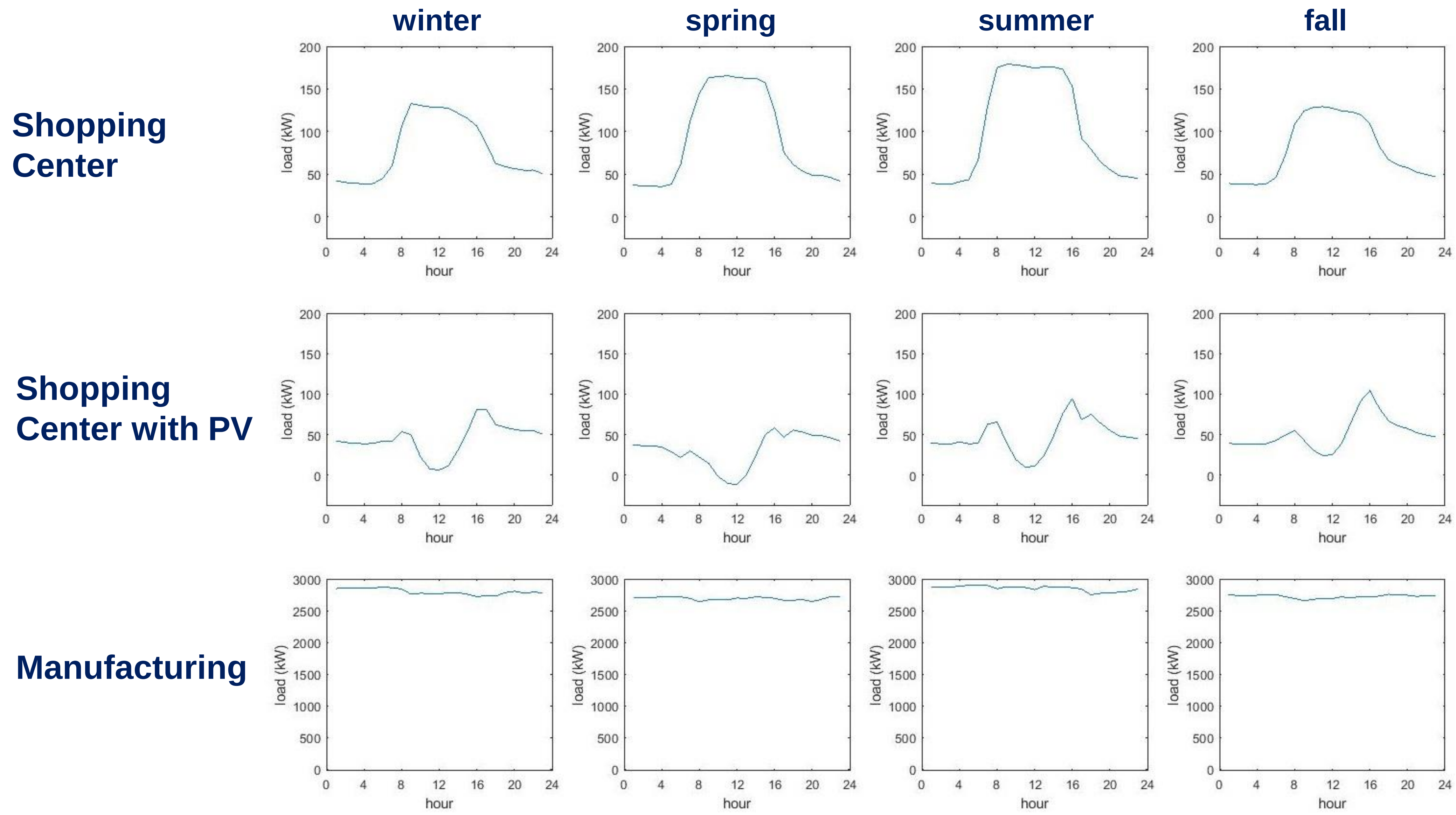
Selected customer types span range of customer characteristics and bill savings from storage



The three building loads selected for analysis capture the relevant range of load-shape attributes

Rate design and analytical methods

Demand charge modeling

Rate Design

- Demand charges calculated with and without storage
- Reference demand charge: $7/kW, non-coincident, 15 minute averaging window
  - Based on median demand charge level in the OpenEI Utility Rate Database (URDB)
- We also consider alternative demand charge rate designs:
  - Demand charge levels
  - Varying peak period definitions
  - Averaging intervals
  - Seasonal demand charge
  - Ratchets

Storage Modeling

- Perfect foresight using HOMER
- Dispatch optimized for demand charge reduction
- Storage capacity (in kW) sized to meet 20% of customer's peak annual load
- Various hours of storage modeled
- Metric: *Annual bill savings per kW of storage capacity ($/kW-yr)*

Rate design and analytical methods
Energy charge arbitrage

Rate Design

- Time-of-use (TOU)
- Critical Peak Pricing (CPP)
- Real-time pricing (RTP)
- Net billing

Storage Modeling

- Storage dispatch optimized for energy arbitrage
- 85% round-trip efficiency
- **Net billing:** Assume that storage can be fully charged from PV generation each day that would otherwise be exported to the grid
- Energy charge savings are largely independent of the underlying customer load shape; results are not specific to either residential or commercial customers
- Compare energy charge savings across rate designs primarily in terms of *annual bill savings per kWh of storage capacity ($/kWh-yr)*

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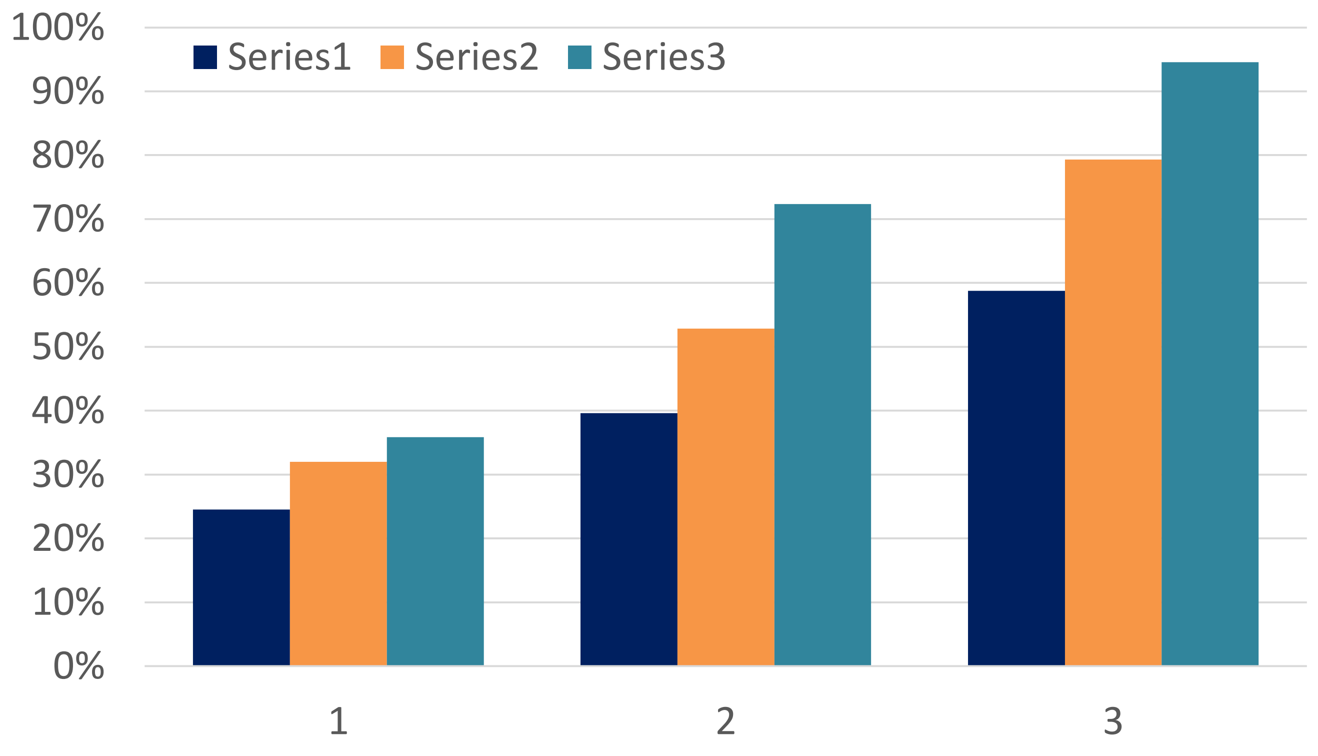
Demand charge savings from storage vary by load shape and storage duration

Demand Charge Reduction Efficiency*
Reference demand charge design

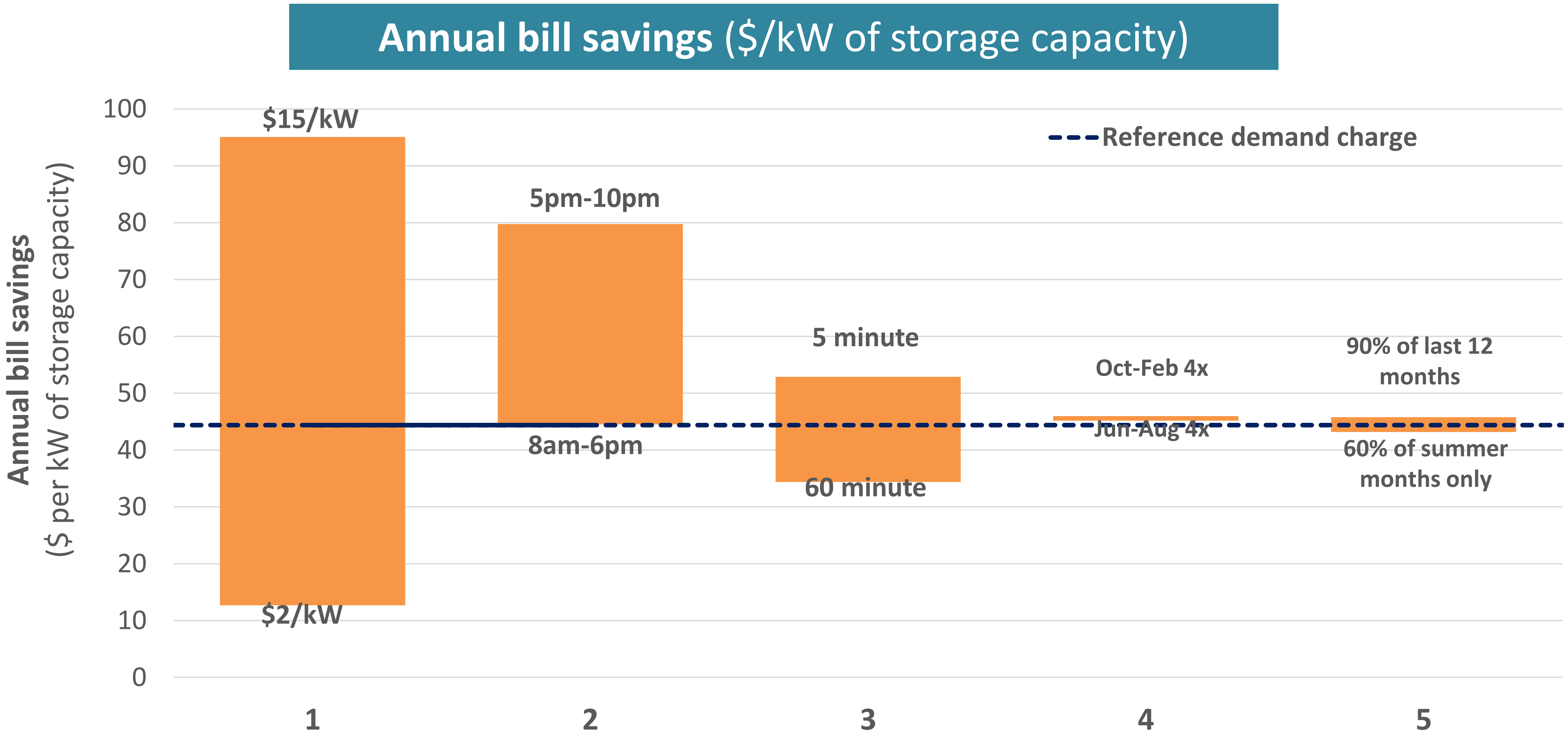


$$\text{* Demand Charge Reduction Efficiency} = \frac{\text{Demand Charge Reduction (kW)}}{\text{Storage System Size (kW)}}$$

- Storage is most effective at reducing demand charges for customers with narrow peaky loads
- Longer duration storage can more effectively reduce demand charges than systems with shorter durations
- Cross-customer differences in demand charge reduction efficiency hold across most demand charge rate designs

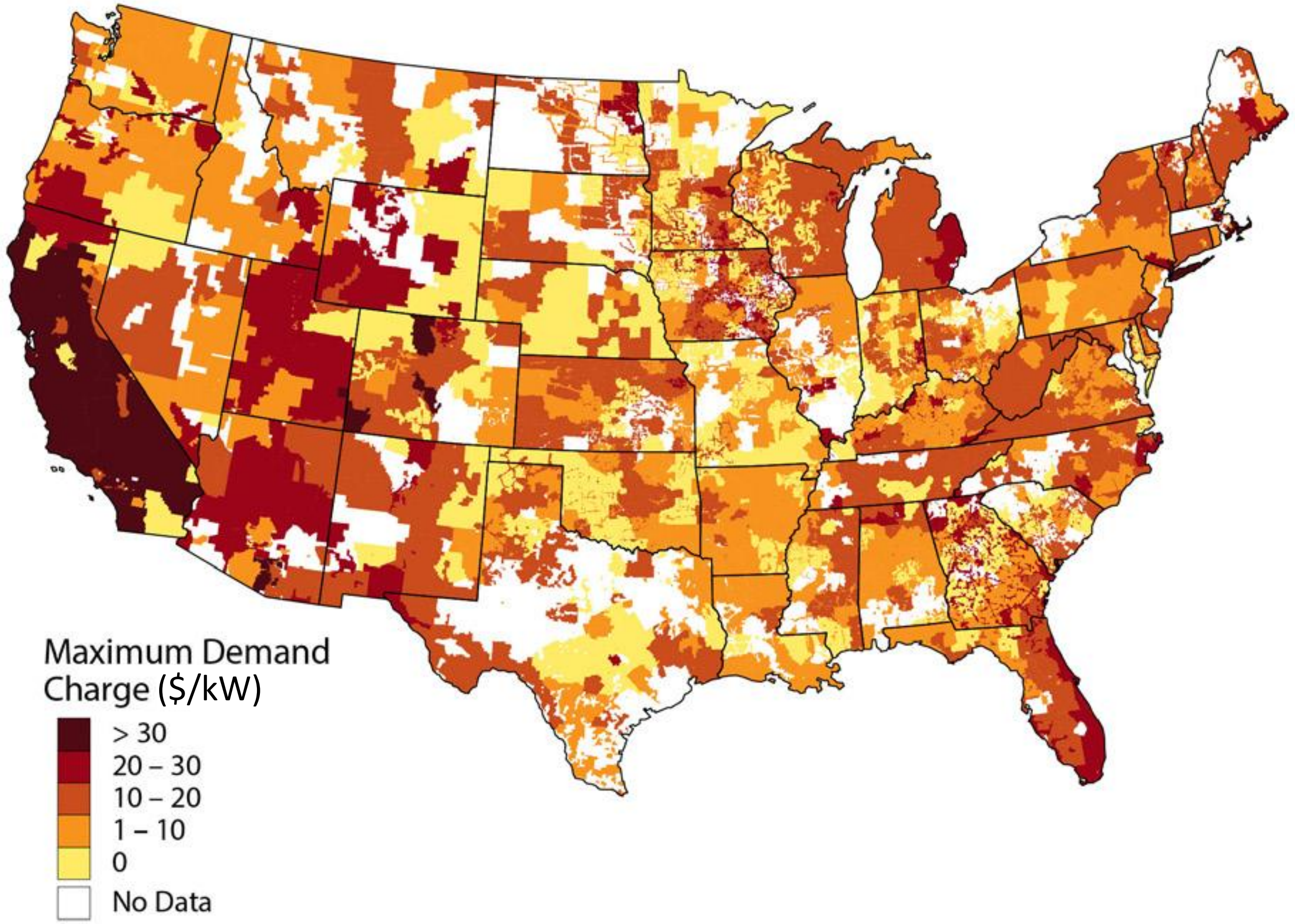
Impact of demand charge design on bill savings from BTM storage

Example: Shopping center, 2-hour storage



Demand charge levels vary widely across the US

Maximum C&I Demand Charge Rate by Utility



Source: NREL. 2017. *Identifying Potential Markets for Behind-the-Meter Battery Energy Storage: A Survey of U.S. Demand Charges*. Golden, CO: National Renewable Energy Laboratory.

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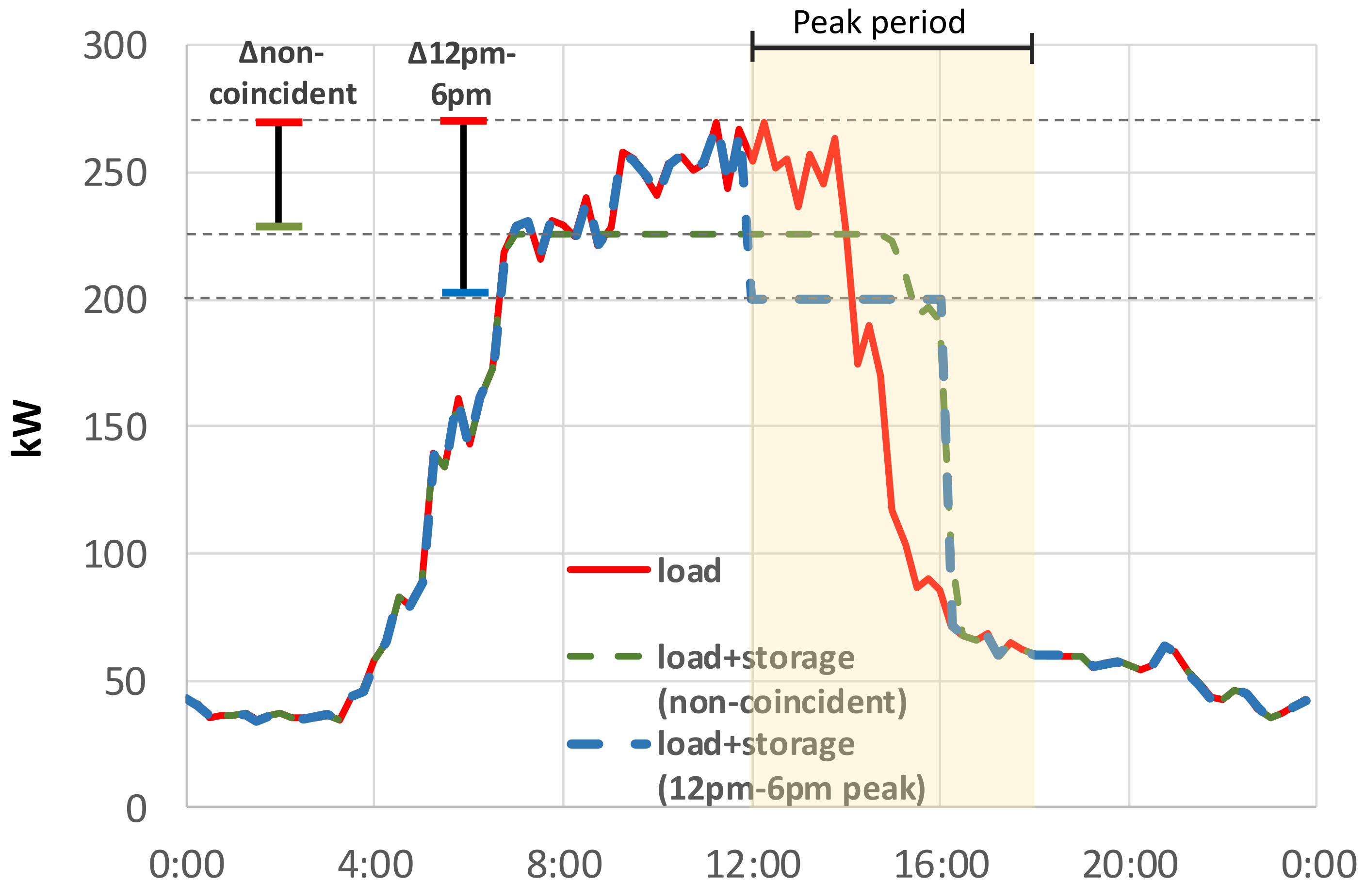
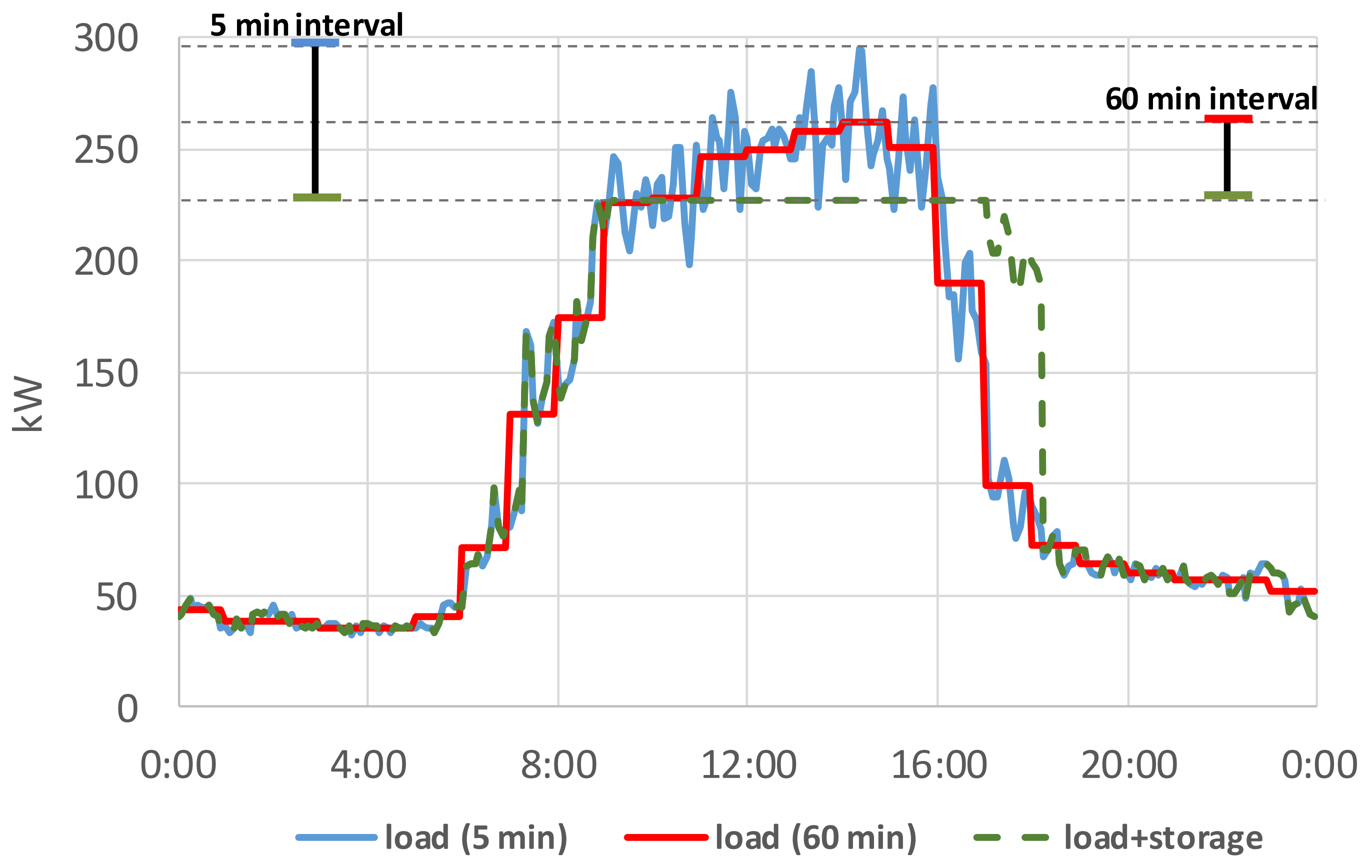
Storage is generally more effective at reducing demand charges when based on “peak period” demand

Billing demand reduction from storage with peak period demand charges



Demand charge savings from storage are greater under demand charges with short averaging intervals

Billing demand reduction from storage for 5 min and 60 min averaging intervals



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- Project Overview
- Data and Methods
- Demand Charge Savings from BTM Storage
- **Energy Charge Savings from BTM Storage**
- Conclusions
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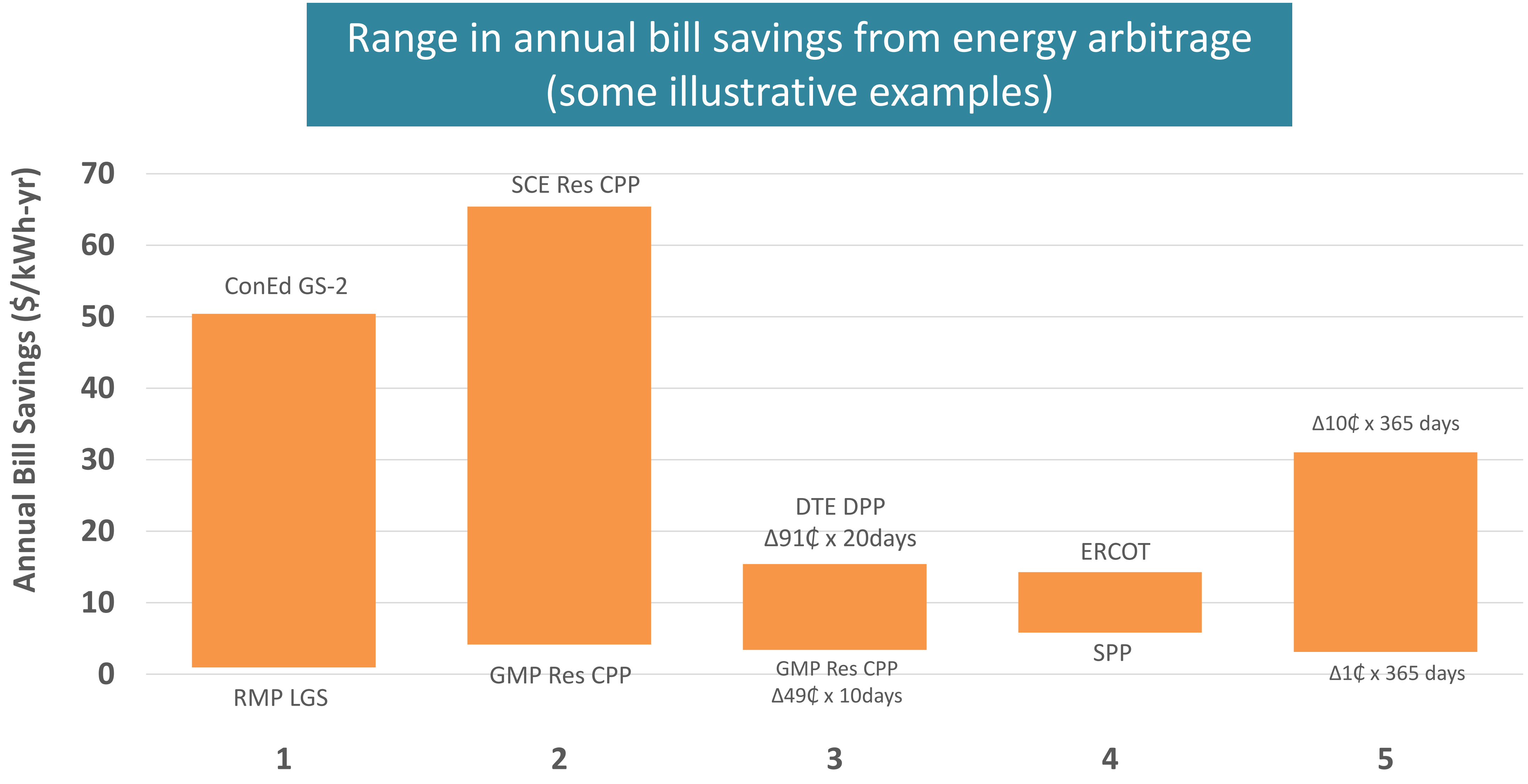
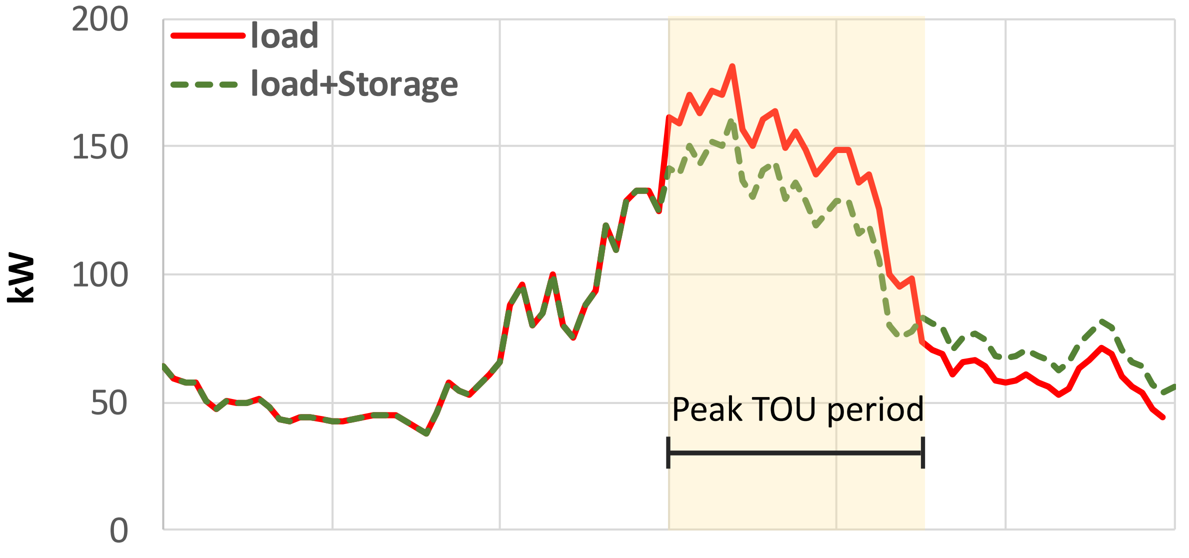
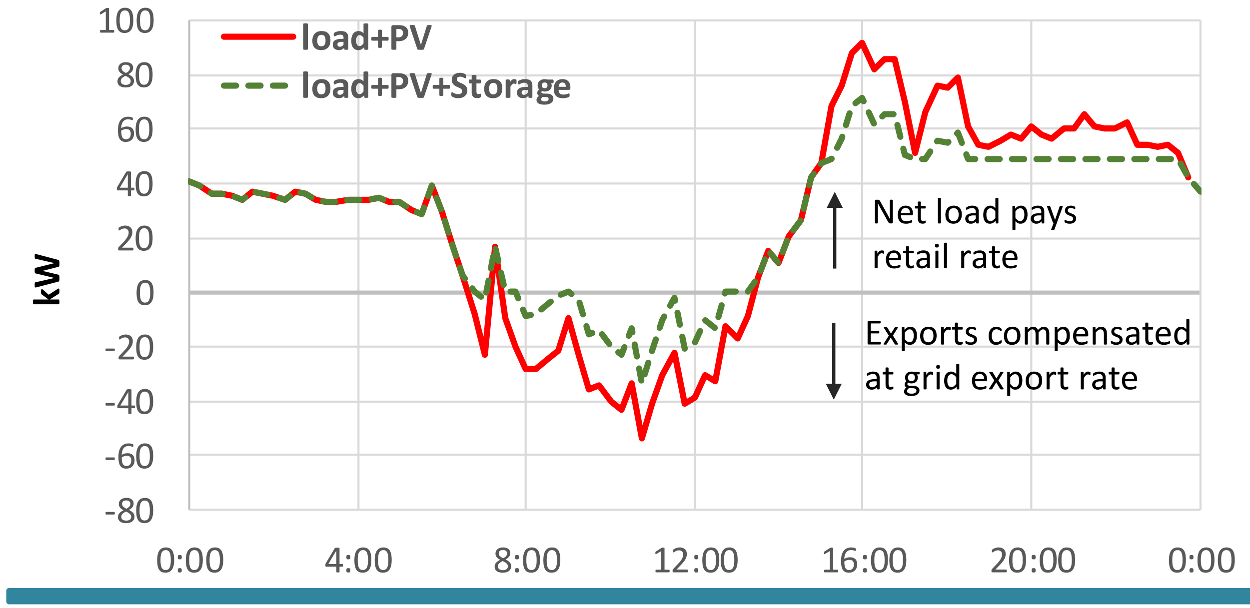
Energy-charge arbitrage savings from BTM storage



Energy price differences enable storage to reduce electricity bills through arbitrage





TOU, CPP, and RTP: Bill savings from storage achieved by charging during low priced hours and discharging during high priced hours

Net billing: Storage manages PV exports to the grid, arbitraging between retail rates and the PV grid export rate

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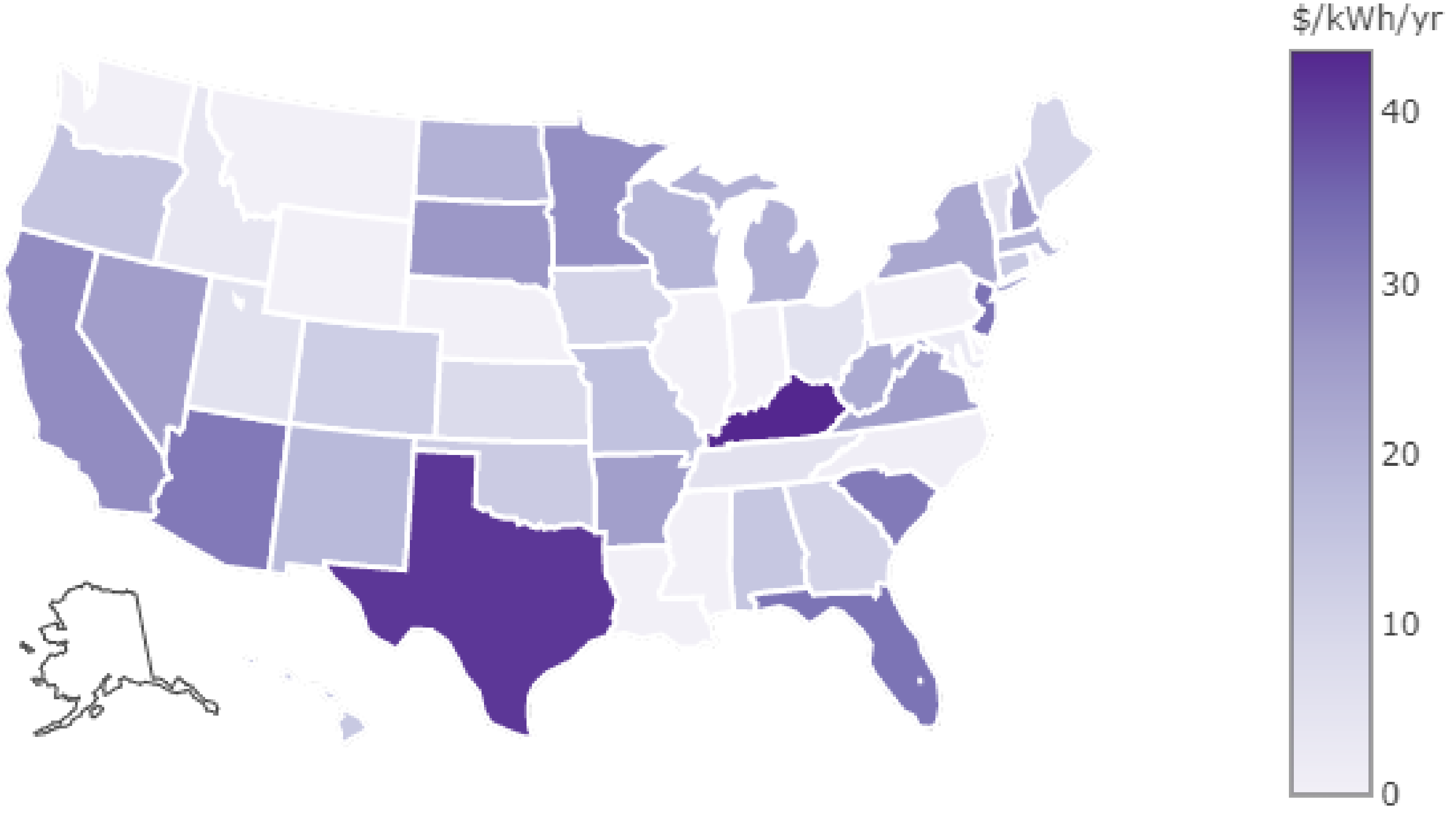
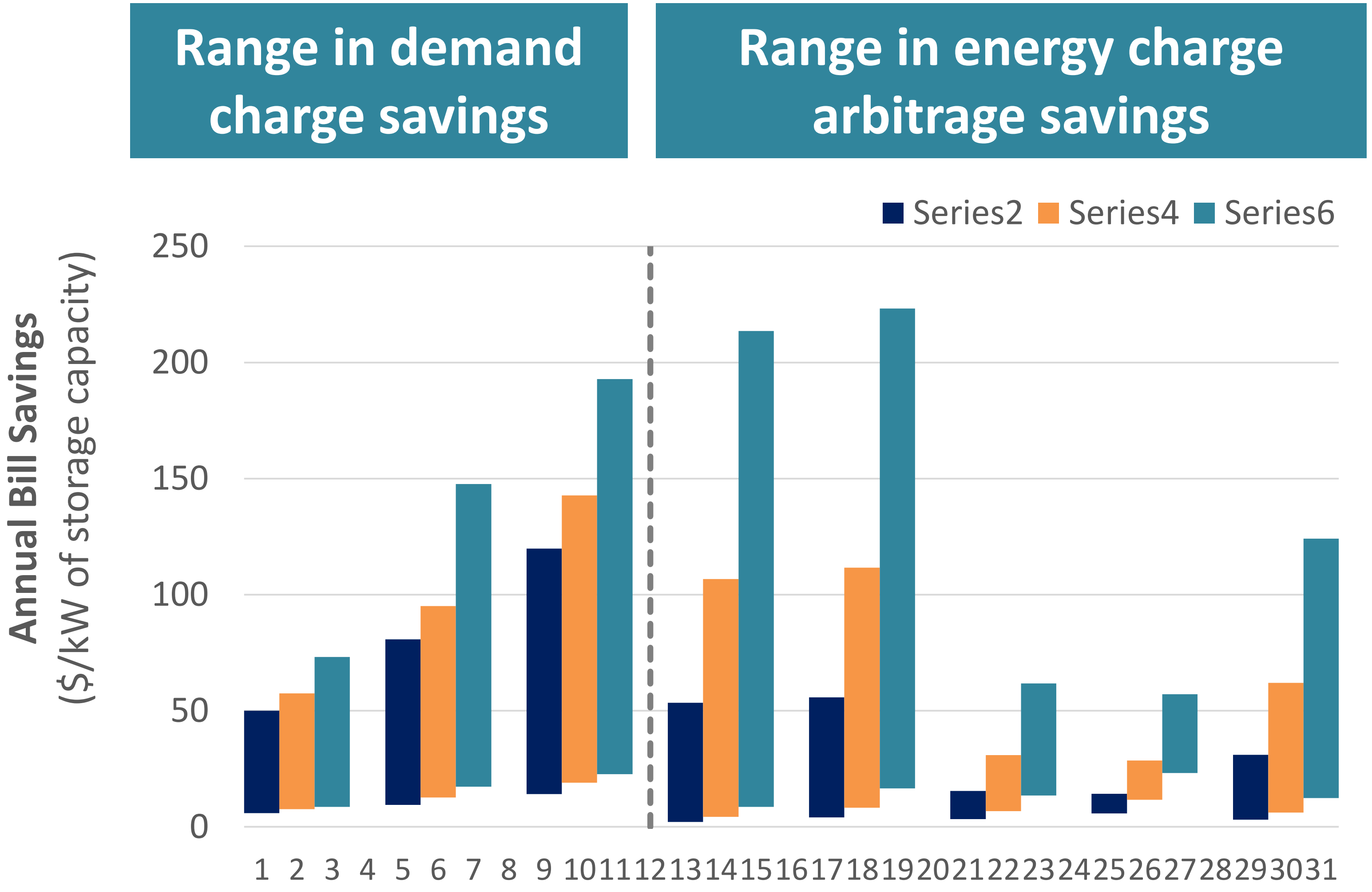
TOU arbitrage opportunities vary by state and utility, primarily reflecting retail rate design choices

Annual value of bill savings from residential TOU arbitrage for the largest utility of each state



Energy arbitrage savings can rival demand charge savings, especially with longer-duration storage



- Some TOU rates and net billing rates offer bill savings on par with, or greater than, demand charge savings—depending on the details of the rate design
- The relative importance of demand vs. energy charge savings also depends on storage duration

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Conclusions

- It's not just about the size of the demand charge: other rate design features are also key to understanding the customer-economics of BTM storage
- Among the rate design elements and customer types considered, demand charge savings range from $8-$143 per kW of storage capacity per year whereas arbitrage savings can range from $4-$112 per kW of storage capacity per year (for a 2 hour duration storage system)
- With longer duration storage, energy arbitrage savings can be (sometimes substantially) larger than demand charge savings

Implications for ratepayers

Time varying rates and demand charges are designed to better align rates with utility costs …

- Price signals designed for demand side management without storage
- A variety of rates, a variety of tools
- Storage dispatched to maximize customer value could theoretically lead to increase in utility costs

… but do they send the "correct" cost-reflective price signals for customer-sited storage?

- As we've seen, the annual bill savings can vary significantly depending on the rate design features chosen and the exact rate definitions
- As always, the challenge will be to strike the balance between cost-reflective rates, simplicity, and fairness

Discussion questions

If customer savings from behind-the-meter storage are greater than utility savings, is there a risk of creating another problem with under-recovery of costs or increases in retail rates?

- Similar issue than for behind-the-meter PV

What strategies could be used to provide value to the customer that approximates the value to the utility for behind-the-meter storage dispatch?

- Could utilities "control" behind-the-meter storage? How would the customer be compensated? Or "what happens behind the meter stays behind the meter"?
- Are there pilots running or in the planning for storage rate design

What research questions related to behind-the-meter storage are you most interested in?

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Utility and rate abbreviations (slides 23 and 25)

			utility	rate
Time-of-use rates	*commercial*	*RMP*	Rocky Montain Power - Utah	Large General Service (No. 8)
		SRP	Salt River Project	Time-of-Use General Service (E-32)
		ConEd	Consolidated Edison Company of NY	General - Small - Time-of-Day (No. 2, Rate II)
	residential	*AEP*	AEP Ohio (Ohio Power Co)	Residential Service - Time-of-Day (RS-TOD)
		ConEd	Consolidated Edison Company of NY	Residential and Religious - Voluntary Time-of-Day (No. 1, Rate III)
		APS	Arizona Public Service	Optional Residential Time-Of-Use (RT)
Critical Peak Pricing	*commercial*	*GMP*	Green Mountain Power	Critical Peak Rider for Commercial and Industrial
		OG&E	Oklahoma Gas and Electric	General Service Variable Peak Pricing
		SCE	Southern California Edison	Critical Peak Pricing
		PG&E	Pacific Gas and Electric	Peak Day Pricing
		DTE	DTE Energy	Dynamic Peak Pricing Rate
	residential	*GMP*	Green Mountain Power	Residential Critical Peak Pricing
		MN Power	Minnesota Power	Critical Peak Pricing
		PG&E	Pacific Gas and Electric	Time-of-Use Rate + Smart Rate
		DTE	DTE Energy	Dynamic Peak Pricing Rate
		SCE	Southern California Edison	Time-of-Use Domestic + Critical Peak Pricing

Utility and rate abbreviations (slide 24)

State	utility	rate
AL	Alabama Power Co	Residential Time Advantage (RTA)
AR	Entergy Arkansas Inc	Optional Residential Time-Of-Use (RT)
AZ	Arizona Public Service Co	Residential Time-of-Use Service, Saver Choice (TOU-E)
CA	Southern California Edison Co	Time-of-Use Domestic (TOU-D)
CO	Public Service Company of Colorado (Xcel Colorado)	Residential Time-of-Use Service (RE-TOU)
CT	Eversource CT	Residential Time-of-Day Electric Service (Rate 7)
DC	Pepco (Exelon)	none
DE	City of Dover - (DE)	none
FL	Florida Power & Light Co	Residential Service (RS-1) + Residential Time-of-Use Rider (RTR-1)
GA	Georgia Power Co	Time of Use - Residential Energy Only (TOU-REO-10)
HI	Hawaiian Electric Co Inc	Residential Time-of-Use Service (TOU-R)
IA	MidAmerican Energy Co	Residential Time-of-Use Service (RST)
ID	Idaho Power Co	Time-of-Day Pilot Plan (schedule 5)
IL	Commonwealth Edison Co	none
IN	Duke Energy Indiana, LLC	none
KS	Westar Energy Inc	Time of Use Pilot
KY	Kentucky Utilities Co	Residential Time-of-Day Energy Service (RTOD-Energy)
LA	Entergy Louisiana LLC	none
MA	National Grid (MA)	Time-of-Use (R-4)
MD	Baltimore Gas & Electric Co	Residential Optional Time-of-Use (schedule RL)
ME	Central Maine Power Co	Residential Service - Optional Time-of-Use
MI	DTE Electric Company	Residential Time-of-Day Service Rate (D1.2)
MN	Northern States Power Co (Xcel)	Residential Time of Day Service (A02)
MO	Union Electric Co - (MO)	Residential Service Rate (No 1(M))
MS	Entergy Mississippi Inc	none

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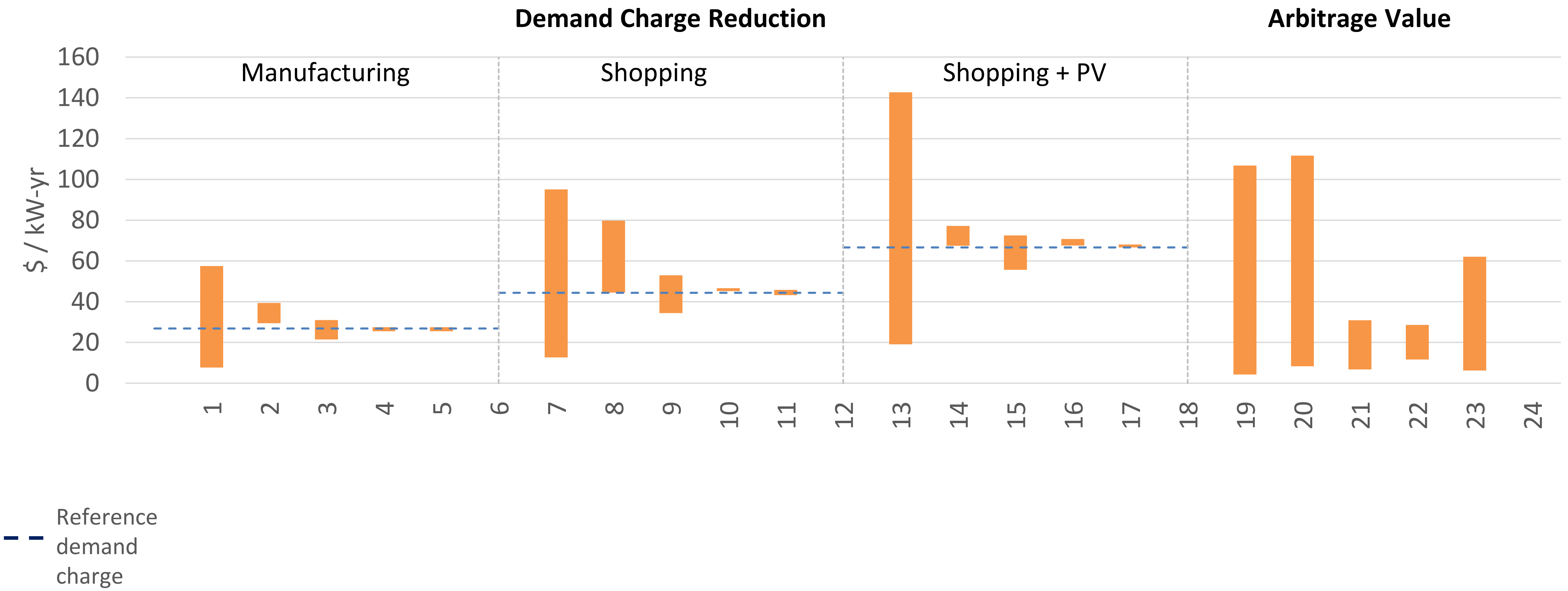
Utility and rate abbreviations (slide 24, continued)

State	utility	rate
MT	NorthWestern Energy LLC - (MT)	none
NC	Duke Energy Carolinas, LLC	Residential Service, Time of Use (RT)
ND	Northern States Power Co - (Xcel Minnesota)	Residential Time of Day Service (D02)
NE	Omaha Public Power District	none
NH	New Hampshire Elec Coop Inc	Residential Time of Day (TOD)
NJ	Public Service Elec & Gas Co	Residential Load Management Service (RLM)
NM	Public Service Co of NM	Residential Service Time-of-Use Rate
NV	Nevada Power Co (NVEnergy)	Optional Residential Service, Time-of-Use (OD-1-TOU)
NY	Consolidated Edison Co-NY Inc	Residential and Religious - Voluntary Time-of-Day (Rate III)
OH	Ohio Power Co (AEP Ohio)	Residential Service - Time-of-Day (RS-TOD)
OK	Oklahoma Gas & Electric Co	Residential Time-of-Use (R-TOU)
OR	Portland General Electric Co	Residential Service (Time-of-Use Portfolio)
PA	PECO Energy Co	none
RI	The Narragansett Electric Co	none
SC	South Carolina Electric&Gas Company	Residential Service Time of Use (Rate 5)
SD	Northern States Power Co (Xcel South Dakota)	Residential Time of Day Electric Service
TN	City of Memphis - (TN)	Time-of-Use Residential Rate (RS-TOU)
TX	TXU Energy Retail Co, LLC	Free Nights and Solar Days 12
UT	PacifiCorp (Rocky Mountain Power)	Residential Service + Optional Time-of-Day Rider -Experimental
VA	Virginia Electric & Power Co (Dominion Power)	Residential Service (1T)
VT	Vermont Electric Cooperative, Inc.	Residential Time of Use
WA	Puget Sound Energy Inc	none
WI	Wisconsin Electric Power Co	Residential Service - Time-of-Use
WV	Appalachian Power Co	Residential Service Time-of-Day (R.S.-T.O.D.)
WY	PacifiCorp	none

Results summary: Comparing demand charge reduction and energy arbitrage value for three customer types

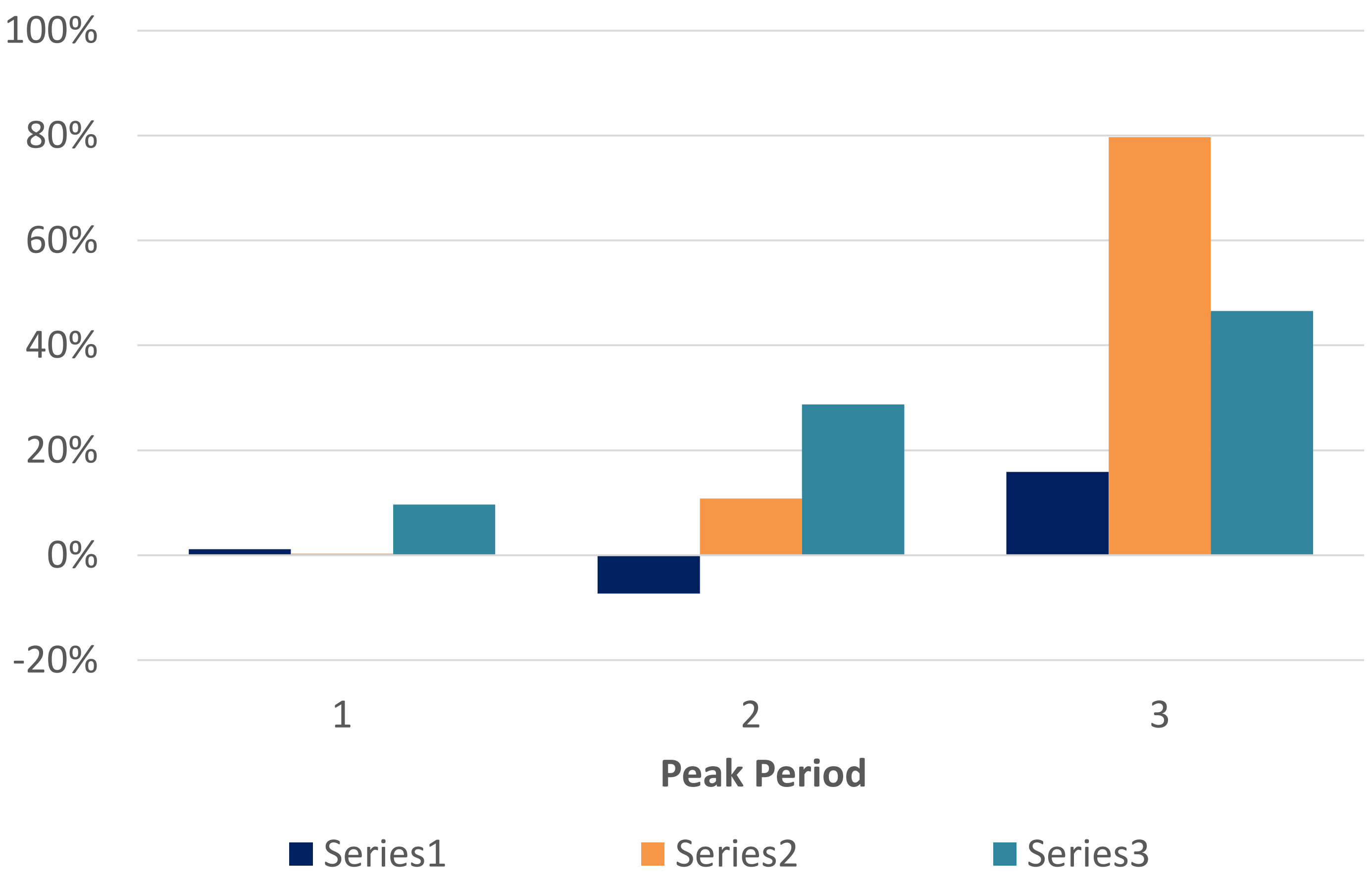
Annual value of bill savings from BTM storage

2-hour storage, storage capacity = 20% of peak demand



An illustration of how peak period timing and duration can impact demand charge savings from storage

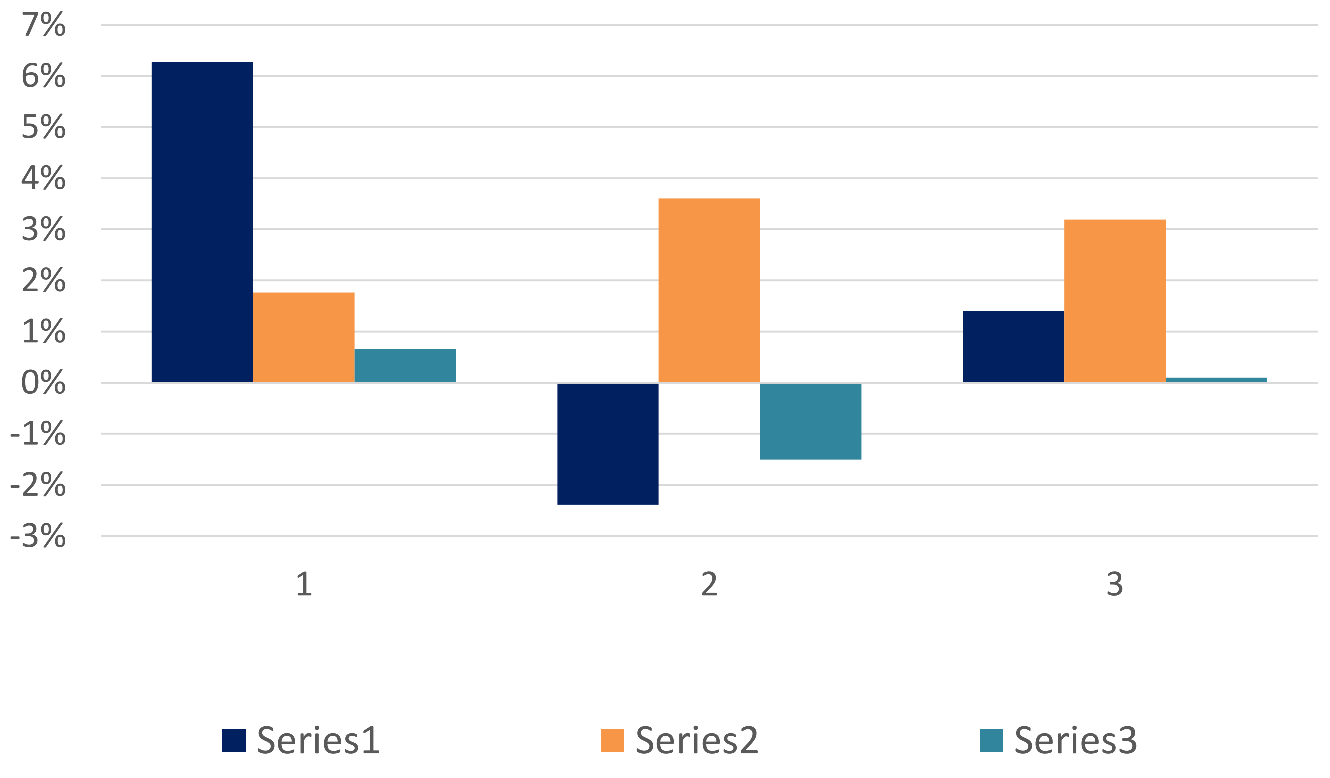
Change in demand charge reduction relative to the reference (non-coincident) demand charge design



- **Shopping center:** the 5pm-10pm window coincides with the down-ramp of the load profile, leading to a steep peak within the window that storage can effectively reduce
- **Shopping center with PV:** net load profile has a skinny peak (and hence greater demand charge saving under a non-coincident design), so the incremental savings from moving to a peak period design are much smaller
- **Manufacturing:** Demand charge savings from storage depend primarily on the duration of the peak period window

Seasonal demand charge rates and ratchets have little impact on demand charge savings from storage

Change in demand charge reduction relative to the reference demand charge design

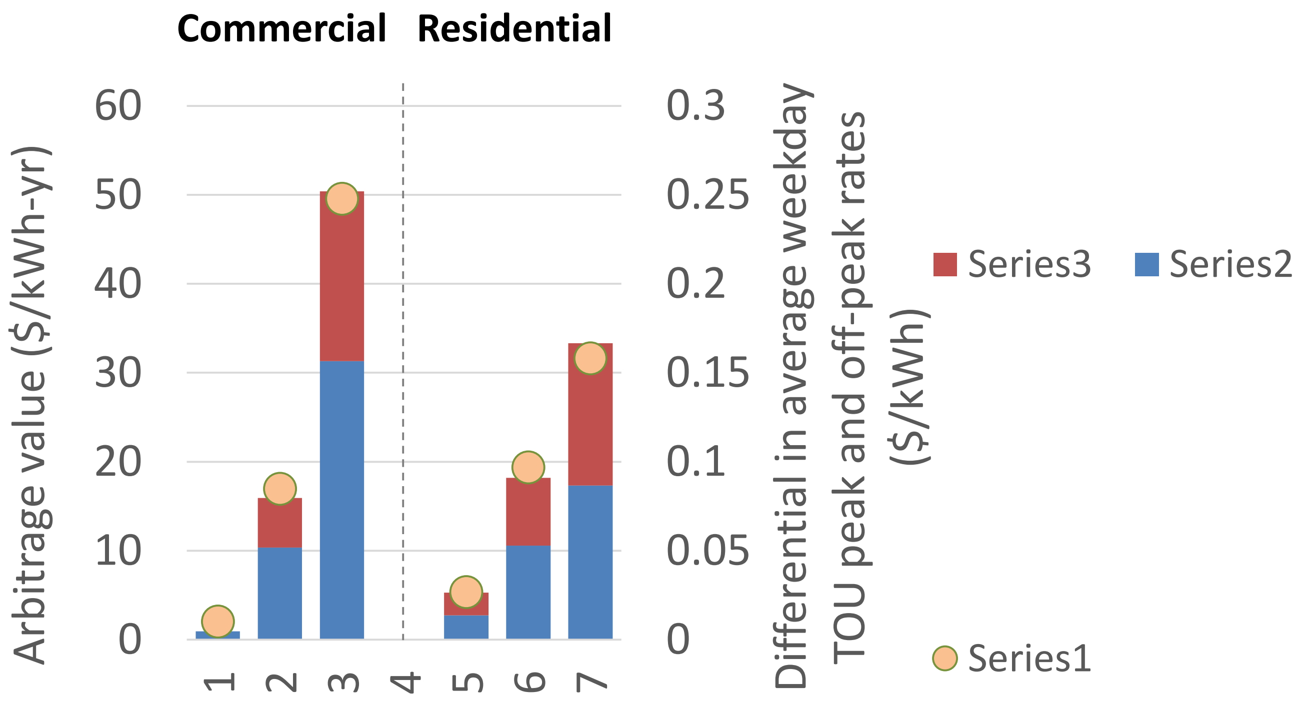


Notes: Summer and winter peaks have demand charge level increased fourfold from June through August and November through February, respectively.

- Seasonal demand charge and ratchet definitions are diverse among utilities
  - Seasonal demand charges can either have higher priced summer or winter peak seasons
- For seasonal demand charges, impacts of storage on demand reduction is small regardless of seasonal definition
  - For customers with PV, storage is more effective at reducing the demand charge in the summer months, when PV is most reliable at creating the “skinny peaks”
  - Though the change in demand charge reduction efficiency can be positive or negative depending on the load profile, the overall impact remains small
- Ratchets can slightly increase the average demand charge reduction efficiency of storage for loads with large month-to-month variation in peak load
  - We also considered a less-binding ratchet (with a 60% threshold) but this had no impact on demand charge reduction efficiency relative to the reference design

Under TOU rates, arbitrage value varies widely depending on differential between peak-period and off-peak rates

Annual value of bill savings from TOU arbitrage for commercial and residential rates

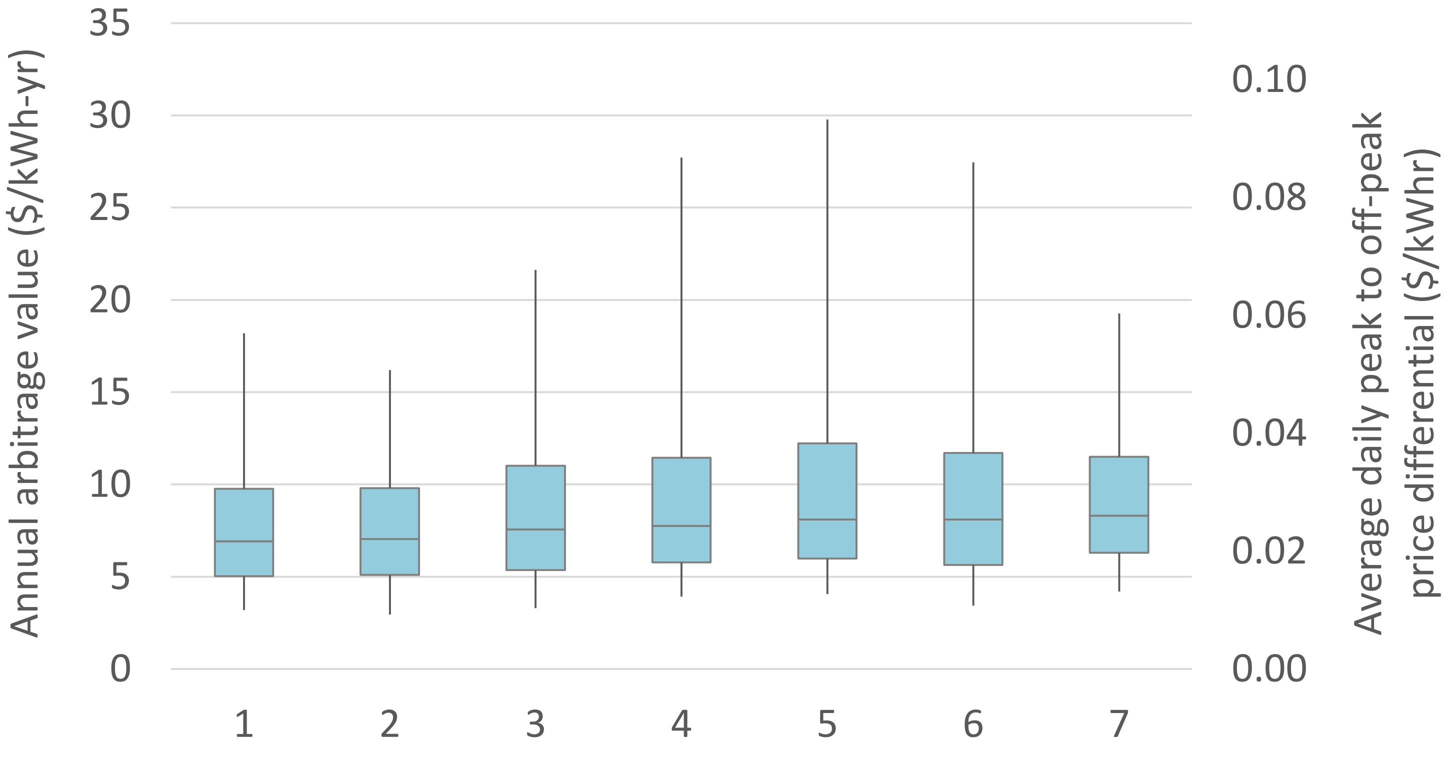


Notes: See Appendix for utility abbreviations and tariff names.

- Computed value of energy arbitrage from storage across large number of TOU rates
- Specific examples shown here illustrate the range in arbitrage-value (~$2-$53/kWh of storage capacity per year)
- Greater bill savings driven by peak-to-off-peak TOU rate differential
  – Differential varies widely across utilities and tariff schedules (<2 cents to >20 cents per kWh)
- Bill savings value from TOU arbitrage can occur disproportionately during May-October
  – Peak period rates may only apply (or are much higher) during these months

Arbitrage value under RTP rates is relatively low compared to the other time-varying rates

Annual value of bill savings from RTP arbitrage
Based on historical day-head hourly prices

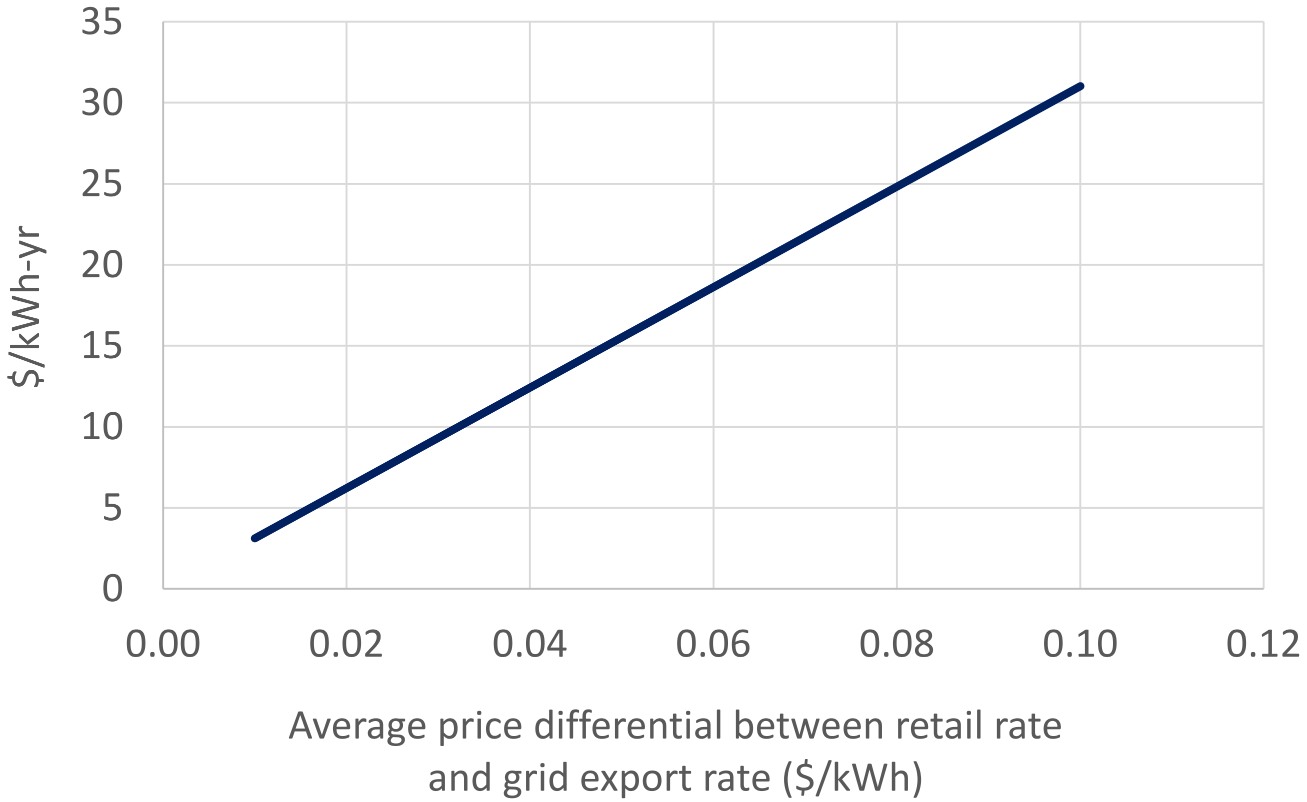


Notes: Based on prices from 100 randomly selected price nodes for each ISO from 2009 or latest market redesign (whichever is later) through August 2018. Storage assumed to be able to charge and discharge fully in the two lowest and highest priced hours of each day, respectively. Box plots represent 5th, 25th, 50th, 75th, and 95th percentiles.

- RTP most common among industrial customers though overall number of customers small compared to TOU (Nezamoddini and Wang 2017)
- RTP arbitrage value has relatively low range and variability across years and markets
  - Typically $6-$14 per kWh of storage per year, though some nodes experience higher price volatility
- Reflects fairly limited differential between average peak and off-peak prices
- Greater hourly variability and arbitrage value possible if:
  - Retail RTP also reflects temporal variability in marginal transmission and distribution costs
  - Growing PV penetration leads to greater price volatility

Arbitrage value under net billing is driven by differential between retail rate and grid export rate

Annual value of bill savings from net billing arbitrage

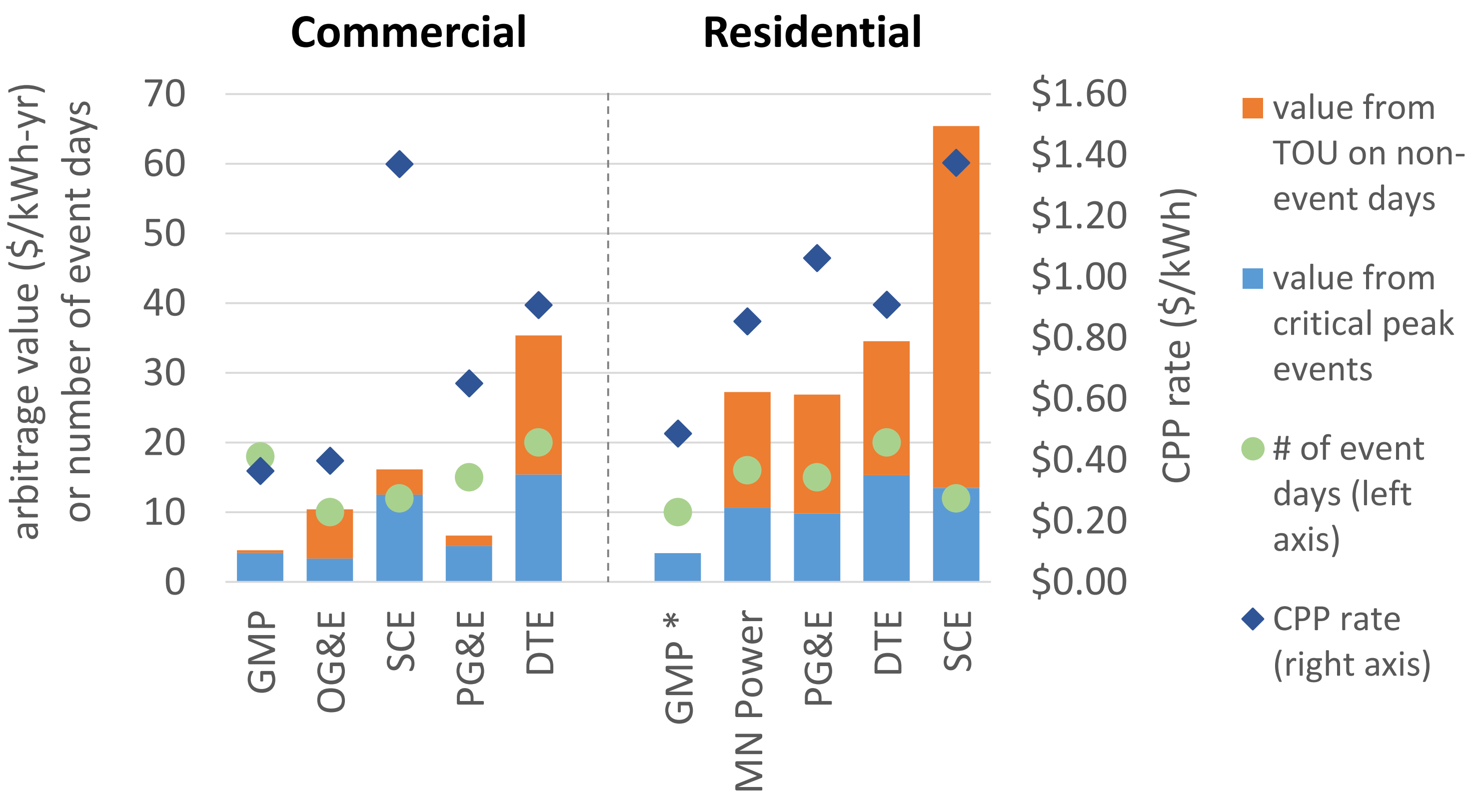


Notes: Assumes enough PV grid exports every day to fully charge storage.

- Net billing has become the successor to NEM in some states: PV exports to the grid are compensated at some designated grid export rate (rather than at retail rates)
- Grid export rates may be based on avoided cost value or in some cases may be more of a political compromise (e.g., during transitional periods away from NEM)
- Differentials between retail rate and grid export rate vary
  - CA Net Metering 2.0: ~$0.02-0.03/kWh differential
  - Rocky Mountain Power: ~$0.02-0.04/kWh differential
  - Arizona Public Service: ~$0.10/kWh differential
- Linear relationship between arbitrage value and retail-to-grid-export price differential (assuming enough grid exports every day to fully charge storage)—see figure
- More applicable to residential customers, which *tend* to have proportionally greater grid exports than commercial customers with PV

Arbitrage value under CPP rates derives mostly from underlying TOU structure, but also depends on level and frequency of critical peak prices

Annual value of bill savings from CPP arbitrage for residential and commercial customers



Notes: See Appendix for utility abbreviations and tariff names. *GMP residential CPP rate has no TOU component.

- Relatively few CPP rates are currently available
- Large range in critical peak price levels and event days per year
- Arbitrage value from storage varies from ~$4-56 per kWh of storage per year