10411 Meeting Street Prospect, KY 40059
502.326.3085
cmta.com

UNDERSTANDING ENERGY PROCUREMENT TO OPTIMIZE DESIGN

WHITEPAPER | SEPTEMBER 2018

Infrastructure Ownership

Customers served by a primary electrical service own and maintain the electrical transformer while the utility meter is located upstream of the transformer. There is typically a lower cost per unit of electricity associated with primary services. On a secondary service, the electrical transformer is owned and maintained by the utility company and the utility meter is located downstream of the transformer. There is generally a higher cost per unit of electricity associated with secondary services but the Owner is not burdened with maintaining the transformer.

Penalties

Electricity providers have numerous means of placing additional charges on consumers based on how electricity is consumed. If not carefully monitored, penalty charges can account for a significant percentage of a customer's total charges. Similar to rate options, the potential severity of these penalties will vary based on HVAC system type and should be carefully considered. One example is a "ratchet" penalty which refers to a minimum demand level that is set and billed for in future months regardless of the actual metered demand (it is like a ratchet tool in that once it is turned, can never go backwards). Consequently, a brief spike in electrical demand of a facility can have major billing ramifications for future months. The severity of penalties varies across electricity providers and can even vary between different rate options offered by a single provider. Common examples include the following:

- Contract capacity demand ratchet
- Previous 11-month peak demand ratchet
- Power factor penalties

Understanding how electricity is procured is an essential part of an optimal HVAC design. The nuances of these utility costs are a significant driver in how buildings should be designed and operated. Several case studies are presented to demonstrate the importance of understanding these details.

CASE STUDY
MORE ENERGY EFFICIENT DOES NOT NECESSARILY CORRESPOND TO LOWER ENERGY COSTS

Energy Usage Index (EUI), measured in thousands of BTU's of energy consumed per square foot in a year (kbtu/sf-yr), is a common metric used to compare the energy efficiency of buildings. However, buildings operating at a lower EUI do not necessarily have lower energy costs. In some cases, the rate structure by which the energy is billed can have an equally significant effect as the system type itself. This concept can be demonstrated by comparing the annual energy consumption and cost for an air-cooled Variable Refrigerant Flow (VRF) system (operating at a 35 EUI with average monthly demand of 3.6 W/sf) versus a natural gas boiler and cooling tower water source heat pump system (operating at a 40 EUI with average monthly demand of 3.7 W/sf). From a pure energy perspective, the VRF system operates at a lower EUI making it more energy efficient. Now consider applying two different electrical rate structures to demonstrate how annual energy costs are affected.

Electrical Rate 1 (ER1) – Consumption Charges Only: $0.12/kWh

Electrical Rate 2 (ER2) – Consumption & Demand Charges: $0.045/kWh & $18/KW. Minimum demand ratchet equal to 50% of the maximum demand occurring over the last 11 months.

Natural Gas Rate: $1.20/therm

	Air Cooled VRF (35 EUI)	WSHP (40 EUI)
ER1	$61,440	**$53,880**
ER2	**$64,980**	$65,160

Table 1 – Annual Energy Cost Comparison

Electrical Rate 1 (ER1) Considerations:
It is clear from Table 1 that when billed on ER1, the 14% more energy intensive Boiler/Tower WSHP system will spend 12% less in annual energy costs than the VRF system. This is directly related to the fact that natural gas is typically less expensive per unit of energy than electricity and ER1 costs are based exclusively on energy consumption while demand charges are out of the equation.

Electrical Rate 2 (ER2) Considerations:
The more efficient VRF system results in slightly lower annual energy costs when comparing the two systems on ER2. This is a consequence of the demand loads and resulting demand charges of the two systems. The lower annual energy cost of the VRF system on ER2 could be more significant, however, it is penalized by the 11-month peak demand ratchet. This can be clearly seen in the following monthly energy breakdown of the two systems.

	VRF System - 35 EUI				Boiler Tower WSHP - 40 EUI				
	Consumption (kWh)	Metered Demand (kW)	Billed Demand (kW)	Total Charges	Consumption (kWh)	Metered Demand (kW)	Billed Demand (kW)	Natural Gas (therms)	Total Charges
January	52,000	320	320	$8,100	41,000	235	235	1,700	$8,115
February	46,000	215	215	$5,940	35,000	210	210	1,500	$7,155
March	43,000	195	195	$5,445	32,000	175	175	900	$5,670
April	38,000	145	160	$4,590	27,000	170	170	500	$4,875
May	37,000	135	160	$4,545	26,000	135	135	200	$3,840
June	28,000	100	160	$4,140	17,000	130	130	10	$3,117
July	29,000	110	160	$4,185	18,000	145	145	15	$3,438
August	53,000	205	205	$6,075	42,000	225	225	20	$5,964
September	47,000	180	180	$5,355	36,000	210	210	55	$5,466
October	41,000	165	165	$4,815	30,000	190	190	100	$4,890
November	44,000	190	190	$5,400	33,000	195	195	500	$5,595
December	54,000	220	220	$6,390	43,000	190	190	1,400	$7,035
Total	512,000	2,180	2,330	**$64,980**	380,000	2,210	2,210	6,900	**$65,160**

Table 2 – 12-Month Energy and Cost Comparison for ER2

Table 2 illustrates that the excessive peak demand in January of 320 kW for the VRF system causes the 50% minimum demand billing ratchet to be applied for the months of April through July (shown in red). This results in the total annual billed demand to be 150 kW higher than the actual metered demand of the system resulting in a $2,700 penalty for the year. In contrast, the Boiler/Tower WSHP system has a smoother demand profile throughout the year resulting in no demand ratchet penalties.

CASE STUDY
INCREASED EMPHASIS
ON ELECTRICAL DEMAND

As electric infrastructure costs out pace fuel costs, electricity providers have utilized demand charges to recover the cost of providing capacity in their system to each user. Commercial electric rates have changed significantly to be driven by this demand component as shown in the Figure 1 below.

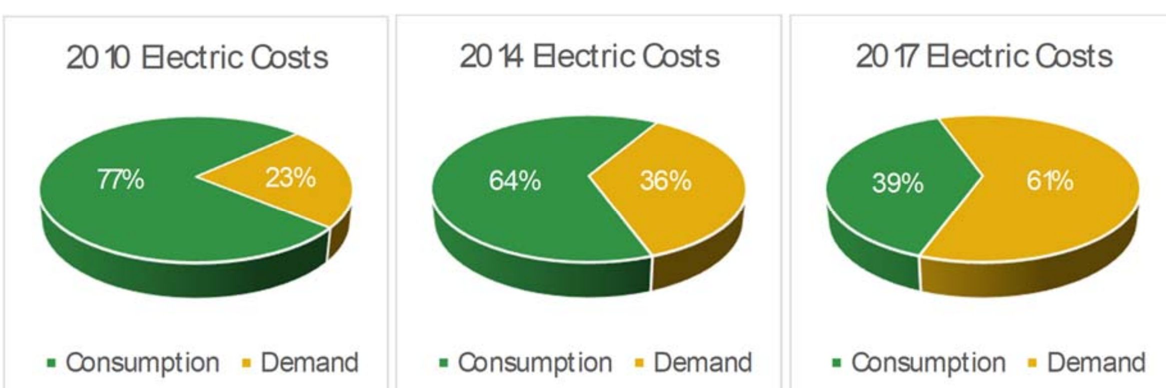

Figure 1. Representative commercial rate change in electric cost breakdown between 2010 and 2017.

For example, a recently opened new college classroom building is operating at an extremely efficient 27 electric EUI. However, it can be seen in Table 3 that 68% of the total electrical charges are associated with the demand component of the bill.

	Annual Billed Charges	% of Bill
Consumption	$10,202	23%
Demand	$30,592	68%
Surcharges	$4,012	9%

Table 3 – Annual Billed Charges Breakdown

Thus, lower EUI will certainly result in lower energy costs for buildings that are billed exclusively on $/kWh consumption charges. However, the average demand per square foot (W/sf) metric can be equally or more important than EUI for buildings that are billed based on both $/kWh consumption charges and $/kW demand charges. Obviously in this sample building, retro-commissioning with a focus on demand reduction strategies (rather than exclusively energy reduction) would be a prudent course of action.

Case Study
Rate Options

One example that demonstrates electrical procurement affecting design decisions is a recent office building HVAC renovation project. This facility qualified for multiple electrical rate options offered by the electricity provider. A favorable rate option was a time-of-day schedule where demand costs were 38% less than the existing rate but required an average monthly demand of greater than 250 kW to qualify. Coincidently, the building was heated with a condensing natural gas boiler and a 160 kW electric back-up boiler. Existing errors in the control sequence were causing the chiller and electric boiler to energize simultaneously for extended periods of time. As a consequence, the system performed poorly from an energy efficiency standpoint but this control sequence error actually allowed the building to qualify for the more attractive rate structure due to the high demand profile.

With no consideration for energy procurement optimization, traditional design principles would have likely replaced the back-up electric boiler with a natural gas condensing boiler, to match the other "new" boiler in place. This is a reasonable decision as it would have standardized equipment and switched heating fuel from electric to gas which is normally recommended. However, this design decision would not have considered the electrical energy procurement for the building. The resulting system would have dropped the average building demand below the 250 kW threshold required to qualify for the more attractive rate option, and missed an opportunity to realize significant cost savings.

It was decided to add a backup gas boiler but leave the 160 kW electric boiler and incorporate it into the new building automation system. A new run schedule was created to operate the electric boiler once a month, with pumps and air handler fans also running at the same time, to meet the minimum 250 kW demand threshold of the more favorable time-of-day rate. The sequence operates the electric boiler at night, during non-peak hours, to minimize the demand cost (on the time-of-day rate option the demand at night costs 80% less than the peak daytime period). Ultimately, the Owner spends $4,000/yr to strategically use the electric boiler to save $20,000/yr by qualifying for the more favorable rate option. Table 4 displays the utility demand data for this facility. The base period kW is intentionally set above the 250 kW threshold.

	Base kW	Interm kW	Peak kW
January	260	112	109
February	256	174	173
March	251	117	112
April	262	127	122
May	260	116	115
June	254	149	149
July	251	126	126
August	251	126	125
September	251	162	156
October	254	118	118
November	247	133	115
December	255	124	106
Average	254	132	127

Table 4 – Monthly Demand Data

CASE STUDY
CONTRACT CAPACITY PENALTIES

Electric companies assign contract capacities to each account (sometimes these are referred to by other names such as "service capacity" or "service agreement"). This capacity is typically set at the maximum amount of demand that the utility company expects a facility to need during the year. A minimum monthly charge will be based on this contracted amount. If the expected load for a facility is not properly coordinated with the utility provider or renovations to the facility have significantly impacted the load, this can result in an improper contract capacity assignment.

Consider a recent LEED certified high-performance facility that was discovered to have significant penalty charges due to an improper contract capacity assignment. The issue was discovered 12 months after substantial completion, but substantial penalties had already been accrued. The building owner had been charged $54,058 (38% of their annual electric costs) more than they should have if they had been set up with the correct contract capacity as shown in Table 5 below.

	Consumption (kWh)	Metered Demand (kW)	Minimum Contract Capacity (kW)	Actual Billed Costs	Cost Based on Electrical Usage	Contract Capacity Penalty	Penalty % of Bill
January	61,632	159	1,250	$12,133	$5,532	$6,601	54%
February	55,872	205	1,250	$11,841	$5,429	$6,412	54%
March	62,496	205	1,250	$12,124	$5,682	$6,442	53%
April	108,288	242	1,250	$11,387	$9,228	$2,158	19%
May	115,776	309	1,250	$11,580	$10,358	$1,222	11%
June	120,384	224	1,250	$11,922	$9,937	$1,986	17%
July	129,600	282	1,250	$11,535	$11,088	$446	4%
August	105,120	268	1,250	$11,829	$9,399	$2,429	21%
September	59,328	250	1,250	$11,980	$6,287	$5,693	48%
October	59,616	270	1,250	$11,974	$6,560	$5,414	45%
November	51,552	168	1,250	$12,446	$5,145	$7,301	59%
December	42,048	156	1,250	$12,289	$4,335	$7,954	65%
Total	971,712	2,737	15,000	$143,040	$88,980	$54,058	38%

Table 5 – Contract Capacity Penalties

CASE STUDY
MULTIPLE ELECTRICAL SERVICES

It is common for all new buildings and major unplanned additions to existing buildings to be given new dedicated electrical services. Consider for example a high school campus consisting of an original building, a major classroom addition, a football field, a fieldhouse and a greenhouse. It is likely that this campus would have five electrical services each with its own monthly meter charges, energy charges and demand charges with associated penalties and ratchets. Without careful optimization there are several scenarios where the annual electrical costs could be excessively high. Below are two common examples of such scenarios:

Scenario 1:
The original building is billed on a consumption only rate with a low blended $/kWh charge which the electricity provider no longer offers to new accounts. When the classroom addition was constructed a new electrical service was designed to serve this added square footage. The new service consists of a consumption and demand charge resulting in a high blended $/kWh charge because there is very little diversity of electrical load in the addition resulting in a high peak (watt per square foot) every month. It would have been more beneficial to the Owner to utilize the existing electrical infrastructure of the original building, assuming it was adequately sized, to serve the classroom addition keeping all square footage on the low blended $/kWh rate.

Scenario 2:
The electrical load for the football field is heavily driven by the field lights which only burn in the fall months at night during games. It is likely that the electrical service for the field has a demand component with a minimum demand ratchet based on a given percentage of the previous 11-month demand peak. Thus, the Owner "pays" for the use of those fixtures all year long even though they only burn during the fall months.

A better solution would be to serve this ballfield from the main building electrical service where the load of these field lights would not affect the billed demand. Not only would this solve the 11-month demand ratchet, it would essentially eliminate the demand charge from the field completely (if the building is on a typical electric rate consisting of charges for consumption and demand). To demonstrate this concept, consider a recent project where the majority of the school building HVAC systems are set to unoccupied by 4:30 pm (leaving only office or after-school activity areas scheduled occupied), and the Owner implemented a policy of not turning on the football field lights before 5 pm. Therefore, the demand peak of the building never occurs at the same time the field lights peak. As a result, the only charge for the field lights is the electrical consumption charge. The demand for the football field therefore is "free" since it does not contribute to the overall demand of the electrical service.

The following data illustrates the financial impact of having the two electrical services billed separately (Table 6) versus servicing the football field from the existing high school electrical service (Table 7). The combined service option results in $10,840 annual savings. This represents a significant 13% cost reduction simply by optimizing the means by which electricity is provided to the site.

	High School Service				Football Field Service				
	Service Charge	Usage	Metered Demand	Billed Demand	Service Charge	Usage	Metered Demand	Billed Demand	Total Cost
January	$240	57,989	208	208	$35	192	1	55	$5,636
February	$240	74,153	213	213	$35	192	1	55	$6,310
March	$240	59,379	208	208	$35	288	105	105	$6,295
April	$240	63,703	337	337	$35	1,872	109	109	$8,122
May	$240	89,578	305	305	$35	1,968	109	109	$8,721
June	$240	53,069	269	269	$35	1,536	109	109	$6,882
July	$240	57,162	226	226	$35	432	2	55	$5,825
August	$240	102,851	322	322	$35	48	0	55	$8,702
September	$240	114,831	337	337	$35	96	0	55	$9,340
October	$240	87,859	274	274	$35	288	2	55	$7,569
November	$240	61,841	249	249	$35	192	1	55	$6,278
December	$240	70,295	207	207	$35	192	1	55	$6,088
Total	$2,880	892,710	3,154	3,154	$420	7,296	438	868	**$85,768**

Table 6 – Annual Electricity Charges Billed as Separate Services

	Combined Service				
	Service Charge	Usage	Metered Demand	Billed Demand	Total Cost
January	$240	58,181	208	208	$4,947
February	$240	74,345	213	213	$5,621
March	$240	59,667	208	208	$5,000
April	$240	65,575	337	337	$6,777
May	$240	91,546	305	305	$7,379
June	$240	54,605	269	269	$5,537
July	$240	57,594	226	226	$5,136
August	$240	102,899	322	322	$8,013
September	$240	114,927	337	337	$8,651
October	$240	88,147	274	274	$6,880
November	$240	62,033	249	249	$5,589
December	$240	70,487	207	207	$5,399
Total	$2,880	900,006	3,154	3,154	**$74,928**

Table 7 – Annual Electricity Charges Billed as a Combined Service

Conclusion

Optimizing high performance mechanical and electrical designs is a science of balancing many variables to deliver the most value to the Owner. Traditionally, considerations such as first cost, ease of maintenance, space requirements, and thermal comfort were given highest priority. As energy costs continue to escalate, high-performing energy efficient systems are of greater importance. As engineers and owners work together to develop and implement high-performance designs it is critical to acknowledge that optimizing energy procurement is equally important and should be heavily considered. Simply stated, in order to optimize both energy efficiency AND energy cost, engineers and designers must be experts with regards to system energy efficiency AND energy procurement.

About the Author

Jonathan Gasser, PE, LEED AP, CxA, CEM

Jonathan is mechanical engineer with the Energy Solutions group at CMTA. He graduated Summa Cum Laude from the University of Kentucky College of Engineering and has worked in the energy efficiency field for the last five years. His most proud accomplishment of his young career is delivering a perfect ENERGY STAR score of 100 to a school in West Liberty, Kentucky (Morgan County School District) through a guaranteed energy savings contract. He is passionate about bringing the most value possible to clients and helping them achieve their energy goals.