



Austin Energy Affordability Benchmarking Study Evaluation of Electricity Rates and Bills

Commercial and Industrial Rate Classes Comparisons Final Report

November 5, 2010



An SAIC Company

Austin Energy Affordability Benchmarking Study Evaluation of Electricity Rates and Bills

Commercial and Industrial Rate Classes Comparisons Report

This report has been prepared for the use of the client for the specific purposes identified in the report. The conclusions and observations contained herein attributed to R. W. Beck, Inc., (“R. W. Beck”) constitute the opinions of R. W. Beck. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report.

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Executive Summary

In support of the Austin City Council’s directive to determine the affordability of Austin Energy’s (“AE”) fully bundled retail rates for residential, commercial, and industrial customers, AE retained R. W. Beck, an SAIC Company and R. J. Covington Consulting, LLC (“R. W. Beck Team”) to publish a study and assist in developing a method for which future changes in AE rates can be fairly evaluated against the financial impact on AE’s customers. In this study, the measure of affordability is defined as the comparison of AE customers’ electricity bills with those of customers of other utilities serving similar loads or demand in similar metropolitan areas within Texas.

Data Availability and Limitations

R. W. Beck’s mission for this study was to compare AE customer electricity bills with customer electricity bills in selected cities across the state. Major challenges exist in comparing electricity bills in different regions. In the competitive areas of Texas, energy service is provided by competitive firms via private contracts between the supplier and the customer. The terms of these contracts are typically confidential. For this reason, it is extremely difficult to collect actual bills and contract provisions for the competitive areas of the state. There is no available collected data set or survey that can be used to compare electricity bills. Since each individual customer may be served under unique terms, knowing the terms and prices of a few customers may not be representative of actual energy prices in the broader market. Therefore, R. W. Beck used several different approaches to estimate representative electricity bills across the state.

In the regulated portions of the state—those served by municipal utilities like AE, by cooperative utilities, and the non-Electric Reliability Council Of Texas (“ERCOT”) portions of the state—utility rates are based on tariffs adopted by regulating authorities, for example city councils. These tariffs include all the costs of providing electric service. However, many factors come into play for these utilities in setting rates and tariffs. These factors include the service territory location within ERCOT, the type and characteristics of the mix of customers in the territory, the strategic aspirations of the utility owners, power supply characteristics including fuel mix and age of assets, and others. The reader should also recognize this comparison is a snapshot of a point in time or period of time and some utilities are in the process of changing tariffs which could change their comparative position within this group. For example, Centerpoint is currently before the Public Utility Commission of Texas (“PUCT”) for a tariff change¹.

R. W. Beck also calculated monthly representative electricity bills for AE’s commercial and industrial customer bills. R. W. Beck used AE rates schedules specified by AE to calculate the representative monthly bills at numerous demand and load factors and our calculations validate AE’s prices reported to the PUCT.

¹ See PUCT Docket No. 38339

Characterizing Commercial and Industrial Retail Market Segments

The charter for R. W. Beck was to compare AE customer electricity bills with customer bills in selected cities across the state. Electricity customer bills consist of two components: (1) electric energy used by the customer—priced by Retail Electric Providers (“REPs”) (which includes the cost to generate electricity, congestion, risk adjustments, and ERCOT fees), and (2) electricity delivery to the customer—priced by Transmission and Distribution Service Providers (“TDSPs”) (which includes the costs of the infrastructure and maintenance to deliver electricity to end use customers). Regional pricing differences will be seen according to the TDSP service territory and the ERCOT congestion zone in which the service is received. Each TDSP has unique delivery charges—reviewed and approved by the PUCT. Energy charges will differ from one congestion zone to another based on the congestion costs incurred across the ERCOT system. Of course, energy charges can vary as well depending on what costs the REP incurs in obtaining energy from generators, as well as marketing costs and other costs unique to each REP.

Utilities and REPs typically classify customers into groups with similar electric service characteristics such as²:

1. Residential customers: Includes private households that utilize energy for such needs as heating, cooling, cooking, lighting and small appliances.
2. Small commercial customers: Includes businesses whose peak electric demand during any twelve-month period is less than 50 kilowatt (“kW”).
3. Commercial customers: Includes businesses such as retail stores, restaurants and educational institutions with a peak demand of 50 kW or more during any twelve month period.
4. Industrial customers: Includes factories or manufacturing plants and typically have the highest demand for electricity.

Definitions of residential, commercial and industrial customers vary slightly from one electric provider to the next. For example, AE typically classifies its *small* commercial customers as those customers with 100 kW load or less. These customer classifications provide a general description of what is commonly used in the industry, and pricing terms for a particular type of customer in one region are appropriately compared to similar customers in other regions or territories. Of these four classifications of customers, electric providers generally view commercial and industrial customers considerably differently than residential customers. This study addresses the commercial and industrial (“C-I”) electricity market segment. The residential electricity market segment is described in a separate companion study within this report. Characteristics of commercial and industrial customers that set them apart from residential customers include greater electricity usage (higher loads), more sophistication in knowledge of electricity markets and physical equipment, additional requirements such as power quality, and the need for varying commercial terms in power supply contracts. Table ES-1,

² Descriptions based on the “Power to Choose” website:
http://www.powertochoose.org/_content/_resources/glossary.asp. Information provided by the PUCT.

provided by AE, shows how AE's C-I customers can be grouped by load size and the typical types of businesses or organizations that fall into each category.

Electricity load groups such as those shown in Table ES-1 help to determine what rate a C-I customer will be charged for electricity. For the regulated utilities, like municipally-owned utilities, these rates are published as tariffs. Tariff terms are typically fixed and the same terms are available to any comparable customer. For AE, the base tariff has been fixed for nearly 17 years, while the fuel factor is typically adjusted annually. However, AE's fuel charge has remained the same since 2008. Thus, the best comparisons against AE's rates are offers of a fixed price and term.

R. W. Beck has chosen to classify customers using 16 load/size factor combinations. This classification protocol was developed by AE and R. W. Beck to provide a diverse and representative sample of AE's different customer types. The variety of customer load sizes range from as small as a 10 kilowatt commercial load to an extremely large 25 megawatt ("MW") customer. Prices for two different load factors for each load level were also estimated. These different load factors are important because the load factor differentiates one dimension in the costs of providing service to a customer—whether the customer has predictable, steady load level, or whether the customer has a highly variable load level and is therefore more expensive to serve. Though we report comparative results for each of these 16 combinations of load and load factor, R. W. Beck cannot emphasize enough that the particular characteristics of each customer will dictate what type of service contract is appropriate for a customer.

**Table ES-1
Austin Energy Commercial and Industrial Examples by kW**

COMMERCIAL SEGMENTATION					INDUSTRIAL
SMALL 10 – 100 kW	SMALL – MEDIUM 100 – 300 kW	MEDIUM 300 – 500 kW	MEDIUM – LARGE 500 – 1MW	LARGE 1 < 3MW	INDUSTRIAL 3MW & OVER
<ul style="list-style-type: none"> ▪ Office condos ▪ Small restaurant ▪ Auto repair ▪ Small retail ▪ Hair/nail salon ▪ Florist ▪ Day care ▪ Dentist office ▪ Gas station ▪ Fast food ▪ Bank ▪ Medium church ▪ Large pharmacy ▪ Large liquor store ▪ Day spa ▪ Auto parts 	<ul style="list-style-type: none"> ▪ Medium-large restaurant ▪ Private school ▪ Small hotel ▪ Small-medium office campus ▪ Radiological office ▪ Bakery ▪ Auto dealer ▪ Cabinet shop ▪ Distribution center ▪ Soup kitchen ▪ Fitness center ▪ Medium hotel ▪ Book store ▪ Elementary school 	<ul style="list-style-type: none"> ▪ Big box retail ▪ Large movie theater ▪ Large sporting goods ▪ Office complex ▪ Large electronics ▪ Large church ▪ Bio technology manufacturing ▪ Medium department store 	<ul style="list-style-type: none"> ▪ Large hotel ▪ Large grocery ▪ Residential high rise ▪ Retirement community ▪ High school ▪ Large department store ▪ Golf/country club 	<ul style="list-style-type: none"> ▪ Hospitals ▪ Medium manufacturing ▪ Regional HQ ▪ High rise office ▪ Large Commercial laundry 	<ul style="list-style-type: none"> ▪ Large data center ▪ Semi-conductor

Source: Austin Energy

Benchmarked Service Providers

R. W. Beck conducted a comparison of calculated AE customer electricity bills with calculated customer electricity bills in selected non-competitive communities across the state and estimated customer electricity bills for the four largest TDSP service territories where REPs compete to serve customers. In the non-competitive areas, the electric utilities serving the selected cities included municipally owned utilities, cooperative utilities, and one investor-owned utility.

Table ES-2 displays the city/metropolitan areas included in our analysis and the corresponding utility provider or TDSP in competitive market areas of Texas. TDSP's provide transmission and distribution service in specific geographic territories while REPs tend to serve a much larger area than one city and/or geographic market and may serve customers in numerous geographic areas. Thus an offer of a REP in one area may not be indicative of an offer from that same REP in a different TDSP territory.

**Table ES-2
Electric Service Providers by City**

City	Electric Service Provider or Territory
Abilene	AEP Texas North [formerly West Texas Utilities]
Austin	Austin Energy (AE)
Beaumont	Entergy Texas
Brownsville	Brownsville Public Utility Board (BPUB)
Cedar Park	Pedernales Electric Cooperative (PEC)
Corpus Christi	AEP Texas Central [formerly Central Power & Light]
Dallas	Oncor [formerly TXU]
Elgin	Bluebonnet Electric Cooperative (BEC)
Houston	Center Point Energy [formerly Reliant Energy Houston Light & Power]
New Braunfels	New Braunfels Utilities (NBU)
San Antonio	CPS Energy
San Marcos	City of San Marcos Utility Service (San Marcos)

Alternative Methods of Estimating Energy Charges

Two methods were used to estimate electricity bills in competitive areas of the state;

1. Heat Rate Method
2. Market Clearing Price of Energy (“MCPE”) Method

AE’s calculated electricity bills based on published tariffs were compared with results from electricity bills estimated using both methods.

Heat Rate factors were estimated for the 16 customer size and usage levels using the R. W. Beck team’s historic knowledge of market pricing for customers in the various competitive zonal sub-markets in ERCOT. For this analysis the range of heat rate factors used varied between a low of 9.4 to a high of 12.0. It is important to remember that these heat rate factors are for retail energy delivered to the distribution utility and include all potential energy charges including ancillary services, losses, ERCOT fees, load following costs, and all REP charges. The assumed heat rate was multiplied by the average natural gas futures prices for 2009 delivery to determine a cost of energy. When appropriate, zonal energy price differentials were also accounted for using annual average historic differences in MCPE zonal energy prices. Once the energy rates were estimated, TDSP charges were calculated for the assumed demand and energy usage of the customer and these costs were added to the calculated energy charges to achieve an estimated total bill.

For the MCPE method, R. W. Beck used historic MCPE data obtained from ERCOT to compute average daily On-peak and Off-peak prices. Average daily pricing was then used to calculate average monthly energy pricing. Sometimes an additional adder is applied by the retail electricity provider to the market price. In this analysis we included a \$0.012 per kilowatt-hours (“kWh”) adder to the reported market price. Once the energy rates were estimated, TDSP charges at the assumed demand and load factor were added to the calculated energy charges to achieve an estimated total monthly bill. Finally, a yearly average bill was calculated at both On-peak and Off-peak pricing levels.

In regulated areas, one comparison method was used. AE’s calculated electricity bills based on published tariffs were compared across the 16 demand and load factor levels with electricity bills calculated for seven electric utility providers in non-competitive areas of Texas. Published tariff rates for these utilities were used to calculate a representative bill for each of the 16 demand and load factor levels. This bill calculation included fixed charges such as a monthly service fee and all applicable variable costs, based on data availability.

R. W. Beck also presented comparisons between AE tariff-calculated electricity bills with information published by the Electric Division of the PUCT. This information provides a commercial monthly electric bill comparison based on data collected from various utilities in markets within Texas that are not yet open to competition. The data is limited to utilities who participate in the survey and computations are provided by each participating utility; hence this analysis was limited to available data. Each utility calculates a typical customer's bill for a total of eight demand/load factor usage levels based on their internal rate tariff.

This study also presents Department Of Energy Information Administration (“DOE-EIA”) based data. This DOE-EIA cannot be used to estimate electricity bills for specific customer classifications of load and load factor. This data is self-reported by utilities at an aggregated level, so only provider-by-provider averages can be used, and even those comparisons should be conducted carefully.

AE Comparative Results

Table ES-3 provides an overview of AE estimated electricity bills compared to the average of electricity bills estimated for other city/metropolitan areas included in our analysis using the Heat Rate and Published Tariffs Methodologies. Table ES-3 does not include MCPE results because this method exhibits considerable volatility in price and higher levels of risk for the customer. Therefore, the MCPE method does not compare well with AE’s approach to pricing electricity. The information provided in the report related to DOE-EIA rate comparisons and the PUCT bill comparison survey was not included because the data provided by the utilities is self-reported and cannot be validated.

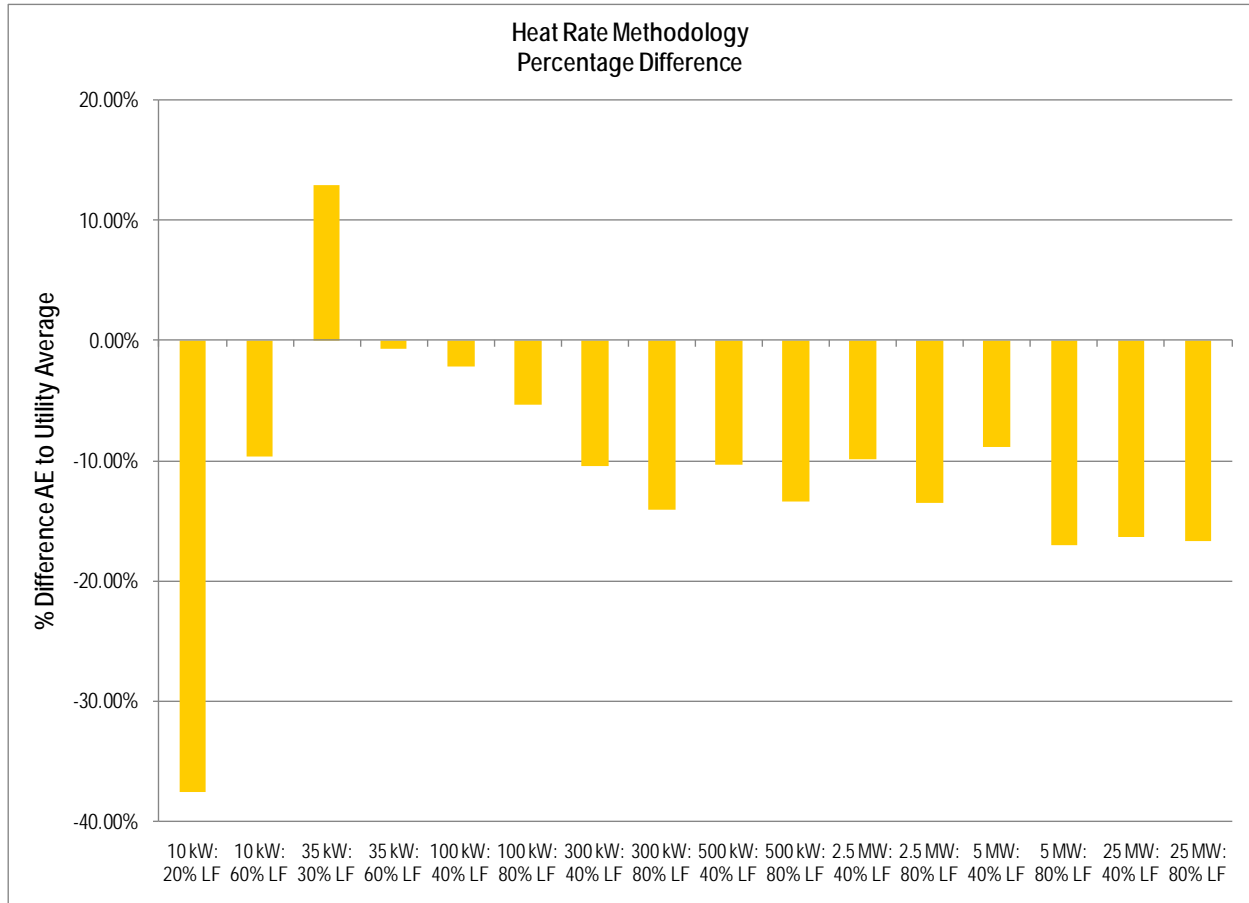
**Table ES-3
AE Bills and Utility Monthly Electricity Bill Averages Summary Comparison**

	Heat Rate Methodology – 2009			Published Tariffs Methodology – Through July 2010		
	Austin Energy (per Tariff)	Utility Average	Percentage Difference	Austin Energy Summer	Utility Average	Percentage Difference
10 kW						
20% Load Factor	\$140	\$193	-37.50%	\$153	\$156	-2.05%
60% Load Factor	409	449	-9.66	448	407	9.22
35 kW*						
7,500 kWh	876	763	12.93	900	713	20.81
15,000 kWh	1,285	1294	-0.68	1,309	1,357	-2.05
100 kW						
40% Load Factor	2,926	2,990	-2.17	2,995	2,526	15.66
80% Load Factor	4,519	4,760	-5.33	4,588	4,580	0.17
300 kW*						
87,000 kWh	7,878	8,669	-10.42	8,027	7,481	6.80
174,000 kWh	12,275	14,007	-14.11	12,424	13,334	-7.32
500 kW*						
145,000 kWh	13,131	14,494	-10.38	13,378	12,405	7.28
290,000 kWh	20,459	23,208	-13.44	20,707	21,857	-5.55
2.50 MW*						
720,000 kWh	65,401	71,837	-9.84	66,639	59,932	10.06
1,440,000 kWh	101,790	115,485	-13.45	103,028	104,239	-1.18
5 MW						
40% Load Factor	125,229	136,242	-8.79	129,447	121,090	6.46
80% Load Factor	190,608	223,154	-17.07	196,193	210,264	-7.17
25 MW						
40% Load Factor	616,978	717,954	-16.33	637,891	573,277	10.13
80% Load Factor	988,539	1,153,502	-16.69	1,062,947	1,007,131	5.25

*Pricing at four demand levels (35 kW, 300 kW, 500 kW, and 2.5 MW) was calculated at the following kWh's rather than at specific load factors to match data provided to the PUCT: 35 kW at 7,500 kWh and 15,000 kWh; 300 kW at 87,000 kWh and 174,000 kWh; 500 kW at 145,000 kWh and 290,000 kWh; 2.5 MW at 720,000 kWh and 1,440,000 kWh.

As illustrated in Figure ES-3 AE's estimated electricity bills compared to bills estimated using the Heat Rate Methodology tend to be lower than the estimated average electricity bills for other city/metropolitan areas at different size and load factors. The only exception where AE is higher than then utility average is at 35kW with a 30 percent load factor.

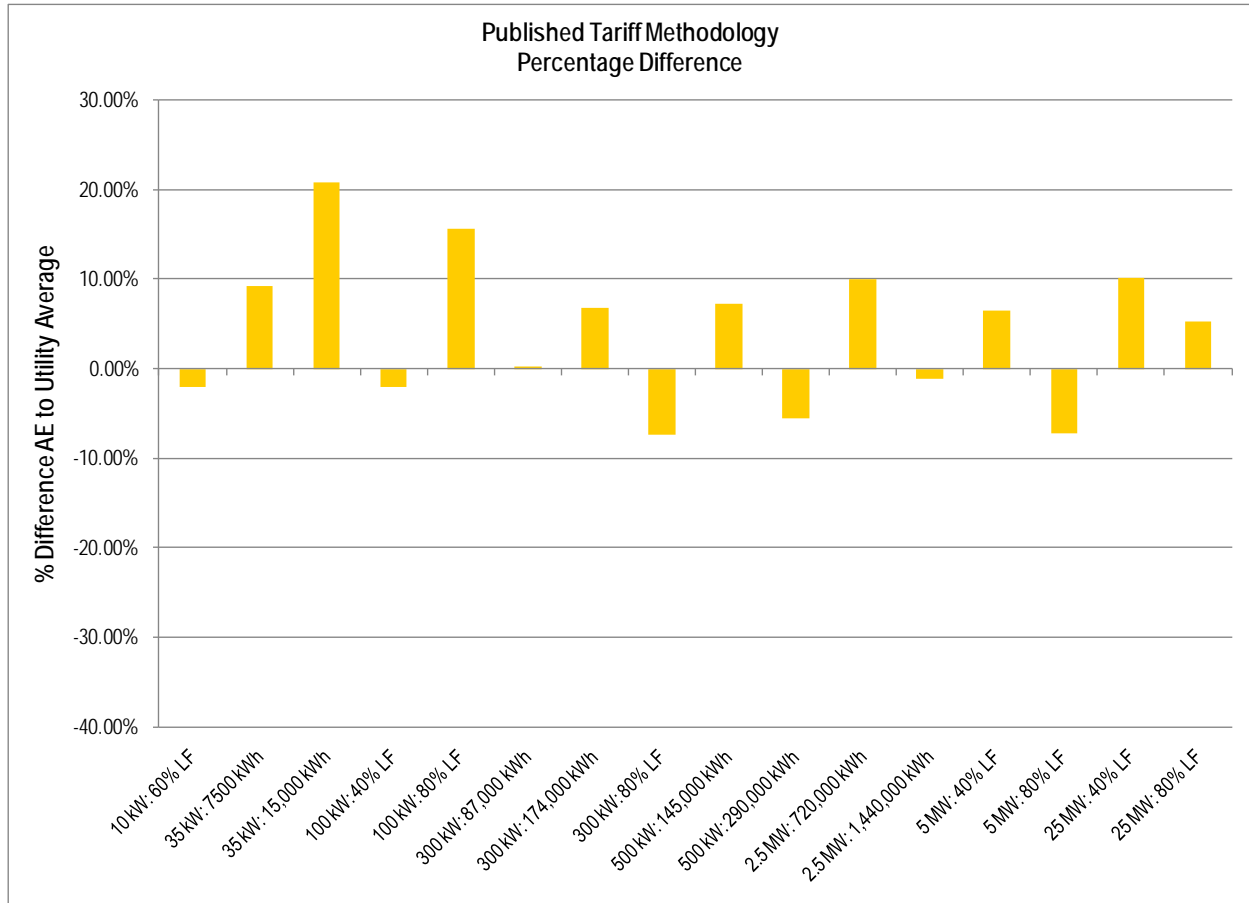
**Figure ES-1:
AE Bills and Utility Monthly Electricity Bill Averages Summary Comparison
Heat Rate Bill Methodology – 2009**



Source: Table 3 of this Report

AE’s estimated electricity bills compared to bills estimated using published tariff information tend to be higher at certain size and load factors. AE’s estimated bills are lower at 10 kW - 20 percent load factor, 35 kW – 15,000 kWh, 300 kW – 174,000 kWh, 500 kW – 290,000 kWh, 2.5 MW – 1,440,000 kWh, and 5 MW at an 80 percent load factor, as illustrated in Figure ES-2.

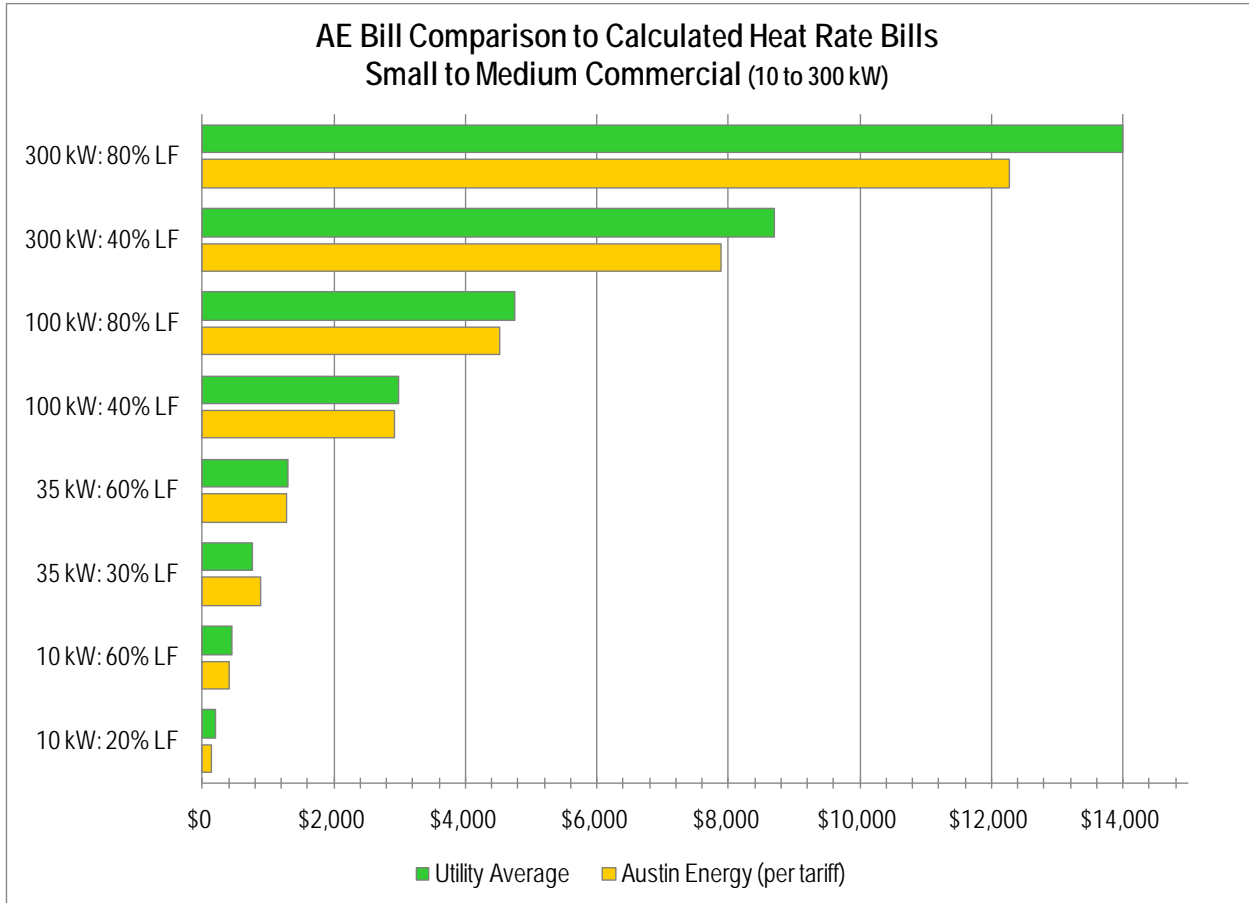
**Figure ES-2:
AE Bills and Utility Monthly Electricity Bill Averages Summary Comparison
Published Tariff Methodology – Through July 2010**



Source: Table 8 of this Report

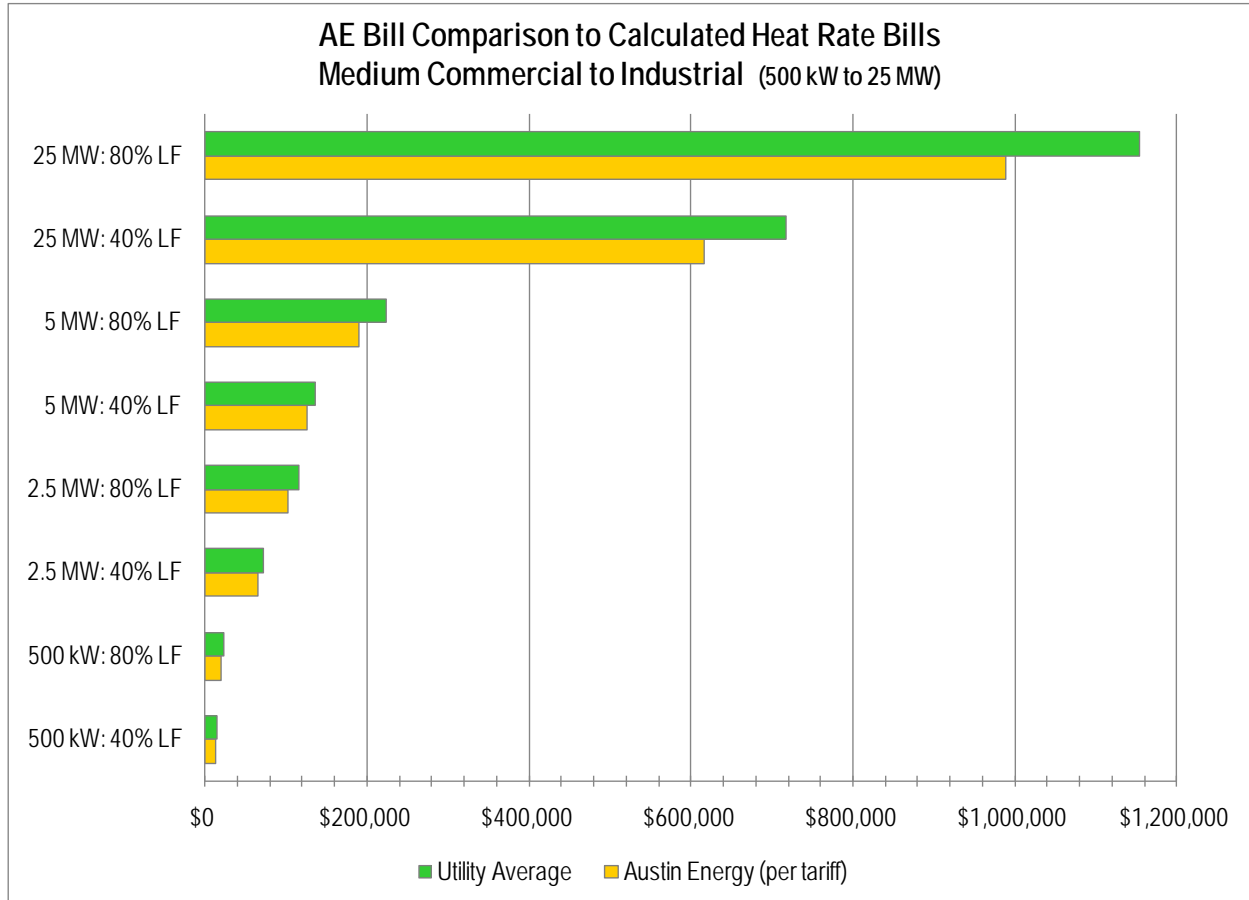
Figures ES-3 and ES-4 show that AE electricity bills calculated from published tariffs compare favorably with the simple average of representative electricity bills for utilities in competitive areas of the state calculated using the Heat Rate method. The estimates indicate that AE’s electricity bills are most competitive for the larger customers. AE’s electricity bills also appear to be more competitive for customers with higher load factors than the comparably sized customers at lower load factors. This could be the result of a policy or organizational objective to create incentives that reward customers with higher load factors. The Heat Rate method compares estimated electricity bills in AE’s territory for each of the 16 load level classifications with the average estimated bill for 2009 in the four TDSP markets in Texas.

**Figure ES-3:
Heat Rate Bill Comparison - Small to Medium Commercial - 2009**



Source: Table 3 of this Report

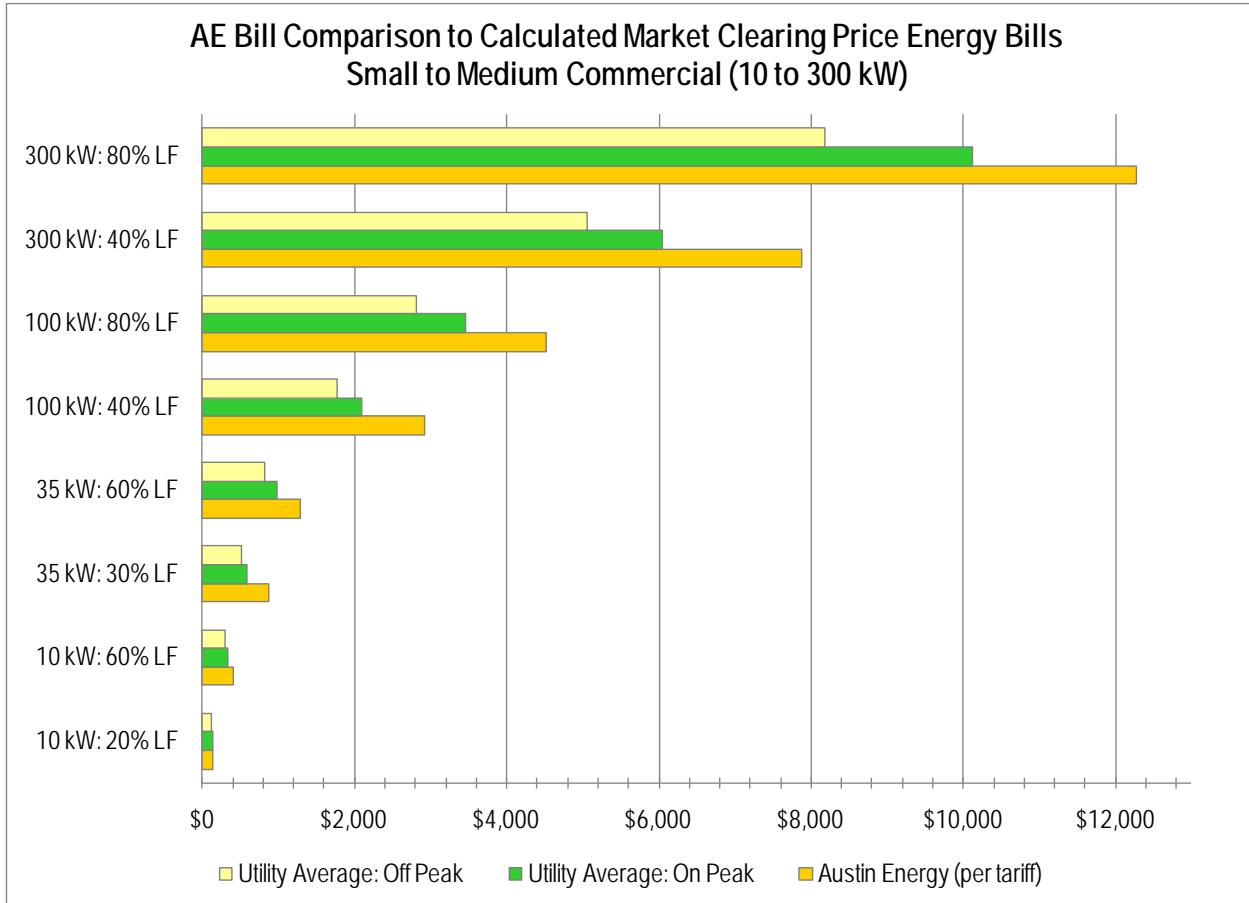
**Figure ES-4:
Heat Rate Bill Comparison - Medium Commercial to Industrial - 2009**



Source: Table 3 of this Report

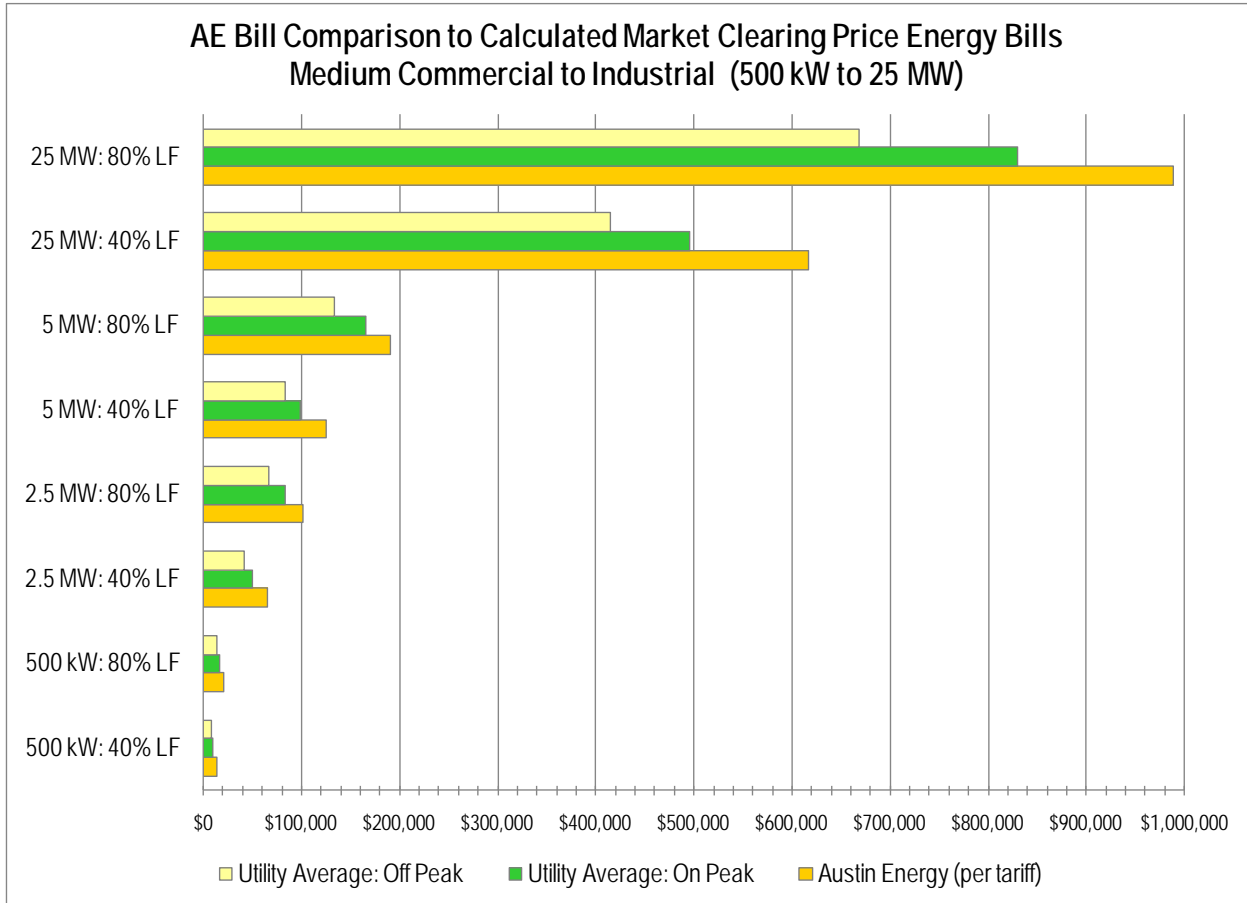
The MCPE method compares the calculated average monthly price at selected demand levels and load factors based on actual market clearing prices for 2009, which are illustrated in Figures ES-5 and ES-6.

**Figure ES-5:
MCPE Bill Comparison – Small to Medium Commercial - 2009**



Source: Table 5 of this Report

**Figure ES-6:
MCPE Bill Comparison - Medium Commercial to Industrial - 2009**



Source: Table 5 of this Report

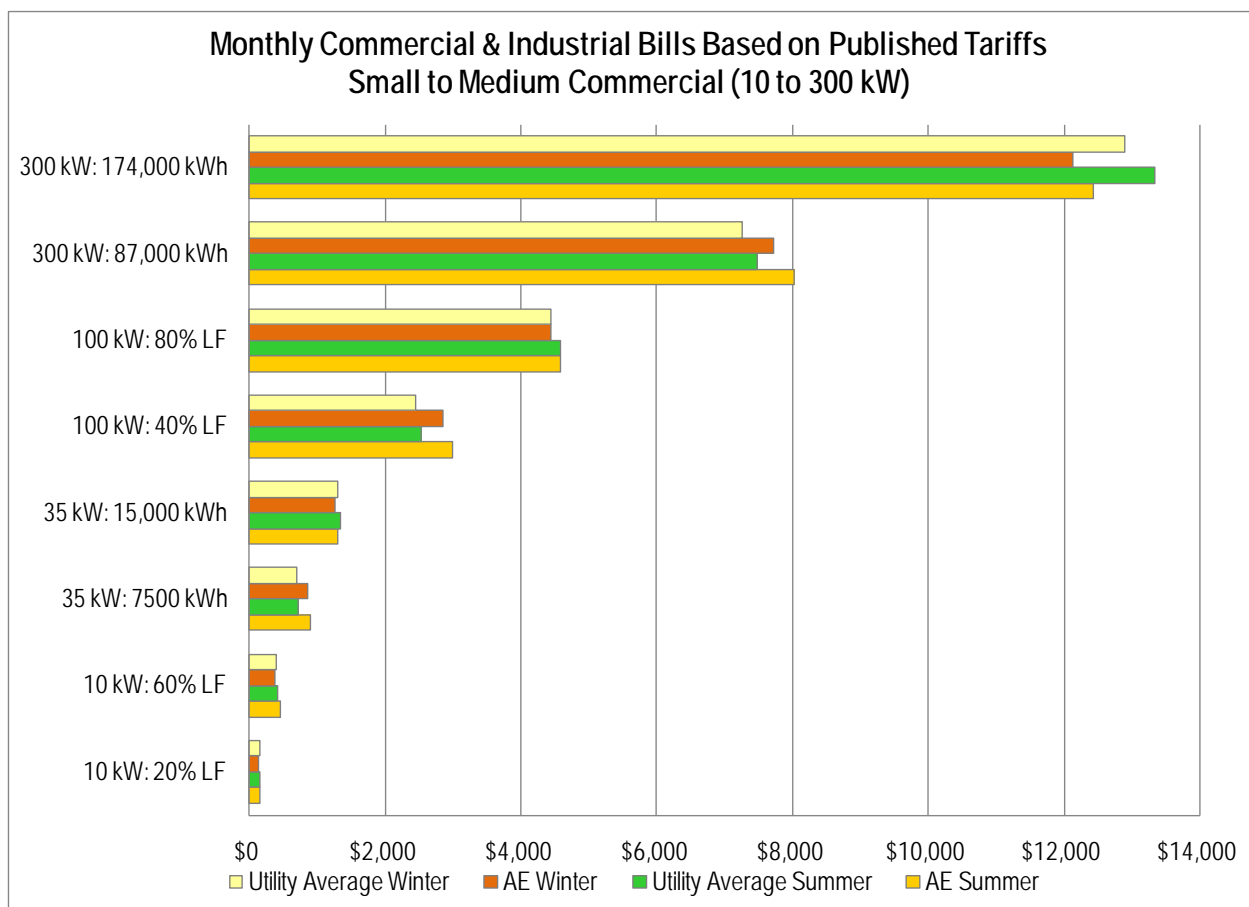
Figures ES-5 and ES-6 show that AE bills calculated from published tariffs are generally higher than the average of representative bills for utilities in competitive areas of the state calculated using the MCPE method. This is to be expected. The MCPE method produces a lower calculated electricity bill than the average of representative electricity bills for utilities in competitive areas of the state calculated using the Heat Rate method. Indeed, with few exceptions the MCPE method will also produce a lower electricity bill than representative electricity bills for utilities in regulated areas based on published tariffs. AE tariffs, like Heat Rate-type electricity supply contracts, are fixed price and exhibit a much lower volatility and energy price risk than MCPE-type contracts. The MCPE method introduces considerable volatility in price and higher levels of risk for the customer.

As expected, electricity bills calculated using published tariffs from a selected group of electric cooperatives and municipal utilities exhibit considerable variability. Many factors come into consideration for these utilities in setting rates and tariffs. Factors include the service territory

location within ERCOT, the strategic aspirations of the utility owners, power supply characteristics including fuel mix and age of assets, among others. The reader should also recognize that this comparison is a snapshot of one point in time or period of time and some utilities are in the process of changing tariffs which could ultimately change their comparative position within this group.

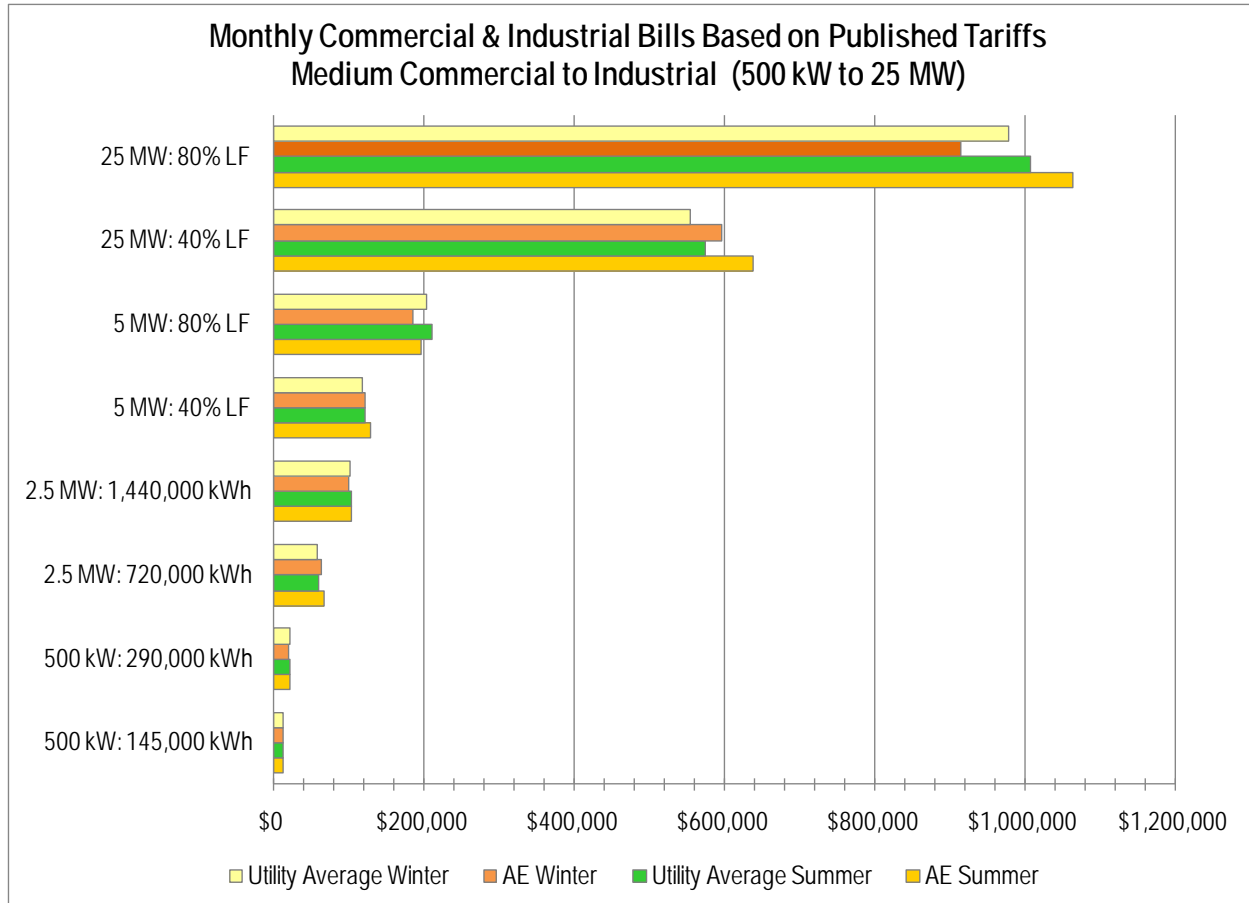
The published tariffs electricity bill comparison compares calculated AE electricity bills to other electricity bills using published public utility tariff information through July 2010, as illustrated in Figures ES-7 and ES-8.

**Figure ES-7:
Published Tariffs Bill Comparison – Small to Medium Commercial – Through July 2010**



Source: Table 8 of this Report

**Figure ES-8:
Published Tariffs Bill Comparison—Medium Commercial to Industrial –
Through July 2010**



Source: Table 8 of this Report

The analysis contained within this study demonstrates that electricity bills calculated using AE’s published tariffs compare favorably with electricity bills estimated or calculated for other competitive and regulated areas of the state. This statement applies to pricing arrangements that are similar to AE’s electricity pricing terms. That is, pricing arrangements that can be categorized as “low risk, fixed term.” Lower pricing arrangements are available in the Texas market, but such arrangements will be higher risk, variable-term arrangements. As such, those arrangements are not similar to AE’s tariff-based pricing.

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Introduction

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Limitations on Availability of Comparative Data

R. W. Beck conducted a comparison of calculated AE customer electricity bills with calculated customer electricity bills in selected cities across the State of Texas. The electric utilities serving the selected cities varied from investor-owned utilities to cooperative utilities to municipally-owned utilities. It is important to recognize that in the competitive areas of Texas, energy service is provided by competitive firms via private contracts between the supplier and the customer. The terms of these contracts are typically confidential. For this reason, it is extremely difficult to collect actual electricity bills and contract provisions for the competitive areas of the state. There is no publicly available collected data set or independent survey that can be used to compare electricity bills. And because each individual customer may be served under unique terms, knowing the terms and prices of a few customers may not be representative of actual energy prices in the broader market. Therefore, R. W. Beck used several different approaches to estimate representative electricity bills across the state.

Components of a Retail Electricity Bill

In the regulated portions of the state—those served by municipal utilities like AE, by cooperative utilities, and the non-Electric Reliability Council Of Texas (“ERCOT”) portions of the state—utility rates are based on tariffs adopted by regulating authorities, such as city councils. Those tariffs include all the costs of providing electric service.

In competitive territories, there are two distinct portions of an electric bill, the regulated wires charges (“transmission and distribution” or “T&D” costs) and the energy charges for providing electric service. Typically two different entities provide these services, transmission and distribution charges are included in the regulated tariffed rates of wires companies (called “Transmission and Distribution Service Providers” or “TDSPs”), while the energy charges are provided by unregulated, competitive Retail Electric Providers (“REPs”). The charges for the wires companies are publicly available. R. W. Beck estimated the energy component of the competitive and hence unknown portion. A customer’s total estimated electric bill is composed of the computed wires charge plus the estimated REP charge.

Alternative Methods of Estimating Energy Charges

To estimate energy charges, R. W. Beck utilized methods similar to those used by REPs to develop customer contract pricing offers. This report uses two different methodologies because customers have options in the competitive market and depending upon the characteristics of an individual customer, may be attracted to different types of offers. Many customers take their service under a fixed priced contract of some term. Length of term (and hence the costs) will vary depending upon the preferences of individual customers. A select set of customers take their service under variable prices. Typically the variability in these prices is linked to the prevailing price of energy in the ERCOT-managed, centralized wholesale market. The ERCOT market price is known as the “Market Clearing Price for Energy” (“MCPE.”) The MCPE is set in each of the four “zones” in ERCOT for every 15 minutes (explained in more detail below). Customers with a risk profile that can tolerate energy price volatility may enter into MCPE-based contracts. Some customers will take their power under a portfolio approach, where a share of their need is served under fixed price contracts, and a share under a variable term.

Since customers are not all alike and often take service under different terms, R. W. Beck used two approaches to calculate representative electricity bills and included additional publicly available data sets. Using multiple approaches helps validate the results of each alternative.

Fixed Price Offers: Heat Rate Method

R. W. Beck used a Heat Rate Methodology to simulate offers that allow a customer the option to fix its energy price. Customers may negotiate for multi-year fixed terms, but historically the extension of the term will often lead to higher contract prices. Fixed price offers are typically used by customers that want to avoid price volatility by establishing a fixed energy price over a specific time period, which is typical of most customers. These results are most comparable to the service terms of AE customers.

Variable Price Offers: Market Clearing Price for Energy Method

The other major approach used in this study, the MCPE methodology, uses spot energy prices as the basis for pricing. Customers receiving service under MCPE contracts will see variability in their electricity prices, in some cases, as often as every 15 minutes. Customers on MCPE contracts can see the price of power spike to as high as \$2,250 per megawatt hour (“MWh”), the maximum ERCOT cap. MCPE contracts are often favored by large, less risk adverse customers, like refineries and steel mills, with the ability to manage price volatility and future price uncertainty. In some cases, customers on MCPE contracts may avoid high prices by shutting down production processes in the event of prices crossing a predetermined threshold. The tradeoff for accepting this additional risk and uncertainty is that this approach has historically resulted in a lower long-run average price for end users. Today, AE does not offer customers a rate comparable to MCPE-based contracts in the competitive market. Where MCPE contracts are available, only a limited set of AE’s largest and most risk tolerant customers would likely be interested in trading a higher level of risk exposure and price uncertainty for a potentially lower price. In this report, R. W. Beck presents MCPE-based estimates for a variety of customer sizes and usage patterns, but for most customers, these should be considered indicative only as many customers will not tolerate the embedded price risks of such offers.

Tariff-Based Estimates in Regulated Territories

For the regulated territories, municipally-owned utilities, cooperative utilities, and investor-owned utilities outside of ERCOT, R. W. Beck used published tariffs to compute hypothetical electricity bills for customers of different sizes and usage patterns (characteristics referred to in the electric industry as “load profiles” or “load factors”). While computed electricity bills are presented for 16 different customer size and load profile classes, comparing electricity bills across these regulated utilities is not a straight forward exercise. For example, while results are presented for each regulated utility at 25 MW—an extremely large customer—some utilities may have no customers of this size. Where a customer of this type seeks service, an entirely new rate may be developed, thus the rate used to estimate a customer’s bill may not be truly representative of what that entity would charge a customer with those characteristics. The customer mix may differ dramatically in these different territories. And regulating entities, like city councils and cooperative boards may use their rate designs to pursue a variety of public policy objectives.

Summary

The two market-based methodological approaches presented in this study, represent a spectrum of potential market prices from risk adverse customers willing to pay a higher price to achieve price certainty to more risk tolerant customers willing to forgo price certainty for the potential to pay less over time. For municipally-owned utilities and electric cooperatives, rates are based on published tariffs, but differences in customer mix, usage patterns, and policy objectives may create variability in electric bill comparisons.

Functioning of the Texas Electric Industry

To understand the differences in the tariff-based rates of regulated electric providers and the competitive electricity prices in deregulated portions of the state, it is important to have a basic understanding of electric market concepts and design. These concepts are also important in understanding the market-based derivation of the heat rate and MCPE-based price projections in this report.

In 2002, Senate Bill 7 opened portions of the Texas electric utility industry to retail competition and customer choice. As a result, customers in areas serviced by investor-owned utilities (“IOUs”) were given the opportunity to choose and purchase electricity from REPs. Municipal utilities and electric cooperatives retain their exclusive right to provide electric service within their territories.

The restructuring of the industry required that the electric utilities unbundle themselves as separate business functions including³:

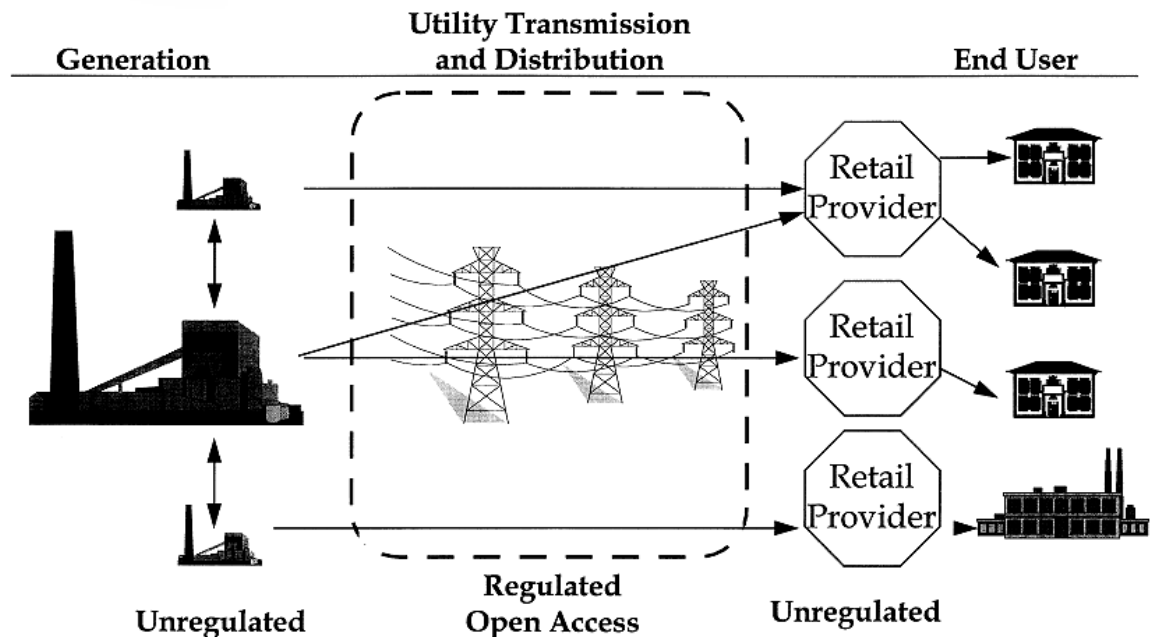
- Generation companies - businesses that produce electricity in Texas from a number of resources including natural gas, coal, nuclear power, wind, water and solar energy.

³ Descriptions based on the “Power to Choose” website: www.powertochoose.org. Information provided by the Public Utility Commission of Texas.

- Transmission and distribution companies – businesses responsible for the actual delivery of the electricity over the poles and wires to the ultimate electricity customer. The Public Utility Commission of Texas (“PUCT”) regulates the rates of these companies.
- Retail Electric Providers – companies that are certified by the PUCT to sell electricity to end use customers.

Figure 1 illustrates how the electric market in Texas is structured.

**Figure 1:
Texas Electric Market**



For purposes of this report, the key entities are the T&D utility and the REPs. In deregulated territories, the wires company retains an exclusive right to provide wires delivery services to end use customers, while the REP sells electricity services directly to customers. Only the REP interacts with retail customers for their electric service, so pricing offers from REPs will include both the regulated wires charges and the unregulated energy charges. Typically as pricing offers are structured, smaller customers may see only a bundled rate or price from the REP, so that the wires charges will be indistinguishable from the commodity electricity charges.

Another key participant in the deregulated electric industry is ERCOT, which serves as the independent system operator that administers and maintains the reliability of the state’s electrical power grid. ERCOT manages the flow of electric power to 22 million Texas customers, representing 85 percent of the state’s electric load. ERCOT schedules power on the Texas grid connecting 40,000 miles of transmission lines and more than 550 power generation units. More

relevant for this study is that ERCOT operates a centralized clearing market for electric services, called the “Balancing Energy Market,” as well as a market for electricity reserves, called the “Ancillary Services Market.” Today, about 5 to 10 percent of total wholesale electricity sales in the ERCOT region are transacted through the ERCOT market; however, after December 1, 2010, 100 percent of the power in the ERCOT region will be managed through ERCOT’s centralized markets.

Balancing Markets⁴

Electricity in ERCOT’s balancing market is traded in four large regions, or zones. Figure 2 shows these four ERCOT zones. Every hour of every day, ERCOT operates an electricity exchange in each of these four zones that sets the market clearing price for electricity in each of the 15 minute intervals of the next hour.

**Figure 2:
ERCOT Zones**



The market-clearing price is the price ERCOT pays for the last megawatt (“MW”) procured for balancing energy, and is paid to all generators providing this service. In the competitive market, this MCPE has become a convenient benchmark for a particular set of retail electricity contracts. That benchmark is discussed in more detail below.

Transmission Congestion Management

The balancing energy market in ERCOT is divided into four zones because delivery of electricity across those zonal boundaries is characterized by significant regional congestion. Electricity purchased for use in a particular geographical area is not necessarily generated there. High voltage transmission lines deliver electricity from the point of production to end use locations,

⁴ Description based on “Window on State Government” website: www.window.state.tx.us. The Energy Report 2008. Appendix 1: The Electricity Market.

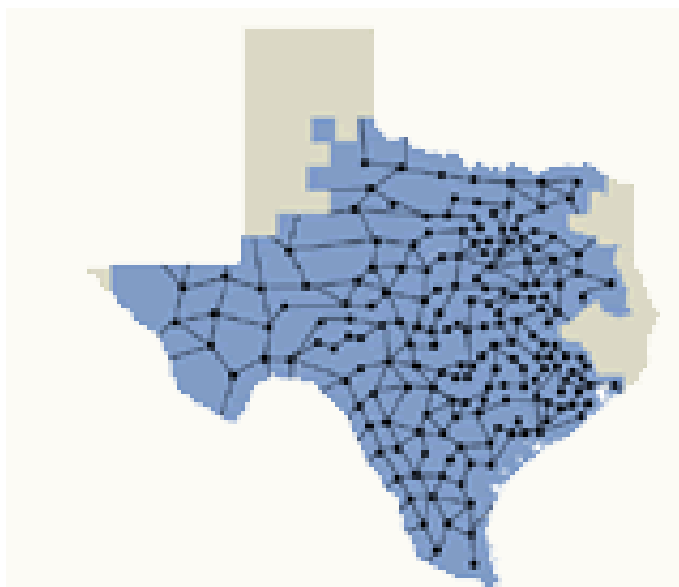
typically urban areas and industrial sites. In the ERCOT market, as in any market with varying prices, cheaper power may be purchased from a generator at some distance away from the user. Moving electricity across the grid from generator to end user often results in congestion — that is, the transmission lines are limited in the amount of power they can reliably carry. And Transmission congestion in ERCOT is most commercially significant across the boundaries of the four congestion zones.

ERCOT operates the balancing energy market to manage congestion across these zonal boundaries. When power flowing between two zones reaches a level that causes significant congestion, ERCOT will deploy “balancing energy service,” buying “up” more power in the receiving zone, and buying “down” more power in the sending zone. This combination of actions will relieve the congested flow of electricity between zones to a reliable level.

As ERCOT operates the balancing energy market every 15 minutes, the MCPE in each zone will rise and fall according to ERCOT’s procurements. Thus, throughout the day, there will be variations in the wholesale prices of electricity across the four regions. And as MCPE is at times used as a benchmark for developing certain retail supply contracts, those contract offers will differ from zone to zone with the expectation of changes in the zonal MCPs.

It is also important to note that AE’s service territory is located in the ERCOT South Zone. When comparing Austin Energy’s prices, it is most relevant to compare to competitive offers within ERCOT’s South Zone. Energy prices available in other zones may not be indicative of offers in the South Zone.

**Figure 3:
Nodal Market**



In December 2010, ERCOT will move to a Nodal Market design. Unlike the current Zonal Market discussed above, Nodal Market unique prices will be calculated every 5 minutes at every generator and major off take point across the grid (see Figure 3 for a high level illustration of pricing points). These prices will then reflect both the costs of power production and the embedded congestion cost associated with that point (or “node”). While large scale changes in congestion patterns and power prices are not expected after the December cutover, certainly some locations will experience changes in delivered electricity costs. As a result, REPs and end use customers may restructure their contracts to nodal pricing points rather than zonal averages as in the contracts existing today.

Characterizing Commercial and Industrial Retail Market Segments

The charter for R. W. Beck was to compare AE customer electricity bills with customer bills in selected cities across the state. Electricity customer bills consist of two components: (1) electric energy used by the customer—priced by REPs (which includes the cost to generate electricity, congestion, risk adjustments, and ERCOT fees), and (2) electricity delivery to the customer—priced by TDSPs (which includes the costs of the infrastructure and maintenance to deliver electricity to end use customers). Regional pricing differences will be seen according to the TDSP service territory and the ERCOT congestion zone in which the service is received. Each TDSP has unique delivery charges—reviewed and approved by the PUCT. Energy charges will differ from one congestion zone to another based on the congestion costs incurred across the ERCOT system. Of course, energy charges can vary as well depending on what costs the REP incurs in obtaining energy from generators, as well as marketing costs and other costs unique to each REP.

Utilities and REPs typically classify customers into groups with similar electric service characteristics such as⁵:

1. Residential customers: Includes private households that utilize energy for such needs as heating, cooling, cooking, lighting and small appliances.
2. Small commercial customers: Includes businesses whose peak electric demand during any twelve-month period is less than 50 kilowatt (“kW”).
3. Commercial customers: Includes businesses such as retail stores, restaurants and educational institutions with a peak demand of 50 kW or more during any twelve month period.
4. Industrial customers: Includes factories or manufacturing plants and typically have the highest demand for electricity.

Definitions of residential, commercial and industrial customers vary slightly from one electric provider to the next. For example, AE typically classifies its *small* commercial customers as those customers with 100 kW load or less. These customer classifications provide a general description of what is commonly used in the industry, and pricing terms for a particular type of customer in one region are appropriately compared to similar customers in other regions or

⁵ Descriptions based on the “Power to Choose” website:
http://www.powertochoose.org/_content/_resources/glossary.asp. Information provided by the PUCT.

territories. Of these four classifications of customers, electric providers generally view commercial and industrial customers considerably differently than residential customers. This study addresses the commercial and industrial (“C-I”) electricity market segment. The residential electricity market segment is described in a separate companion study within this report. Characteristics of commercial and industrial customers that set them apart from residential customers include greater electricity usage (higher loads), more sophistication in knowledge of electricity markets and physical equipment, additional requirements such as power quality, and the need for varying commercial terms in power supply contracts.

The most basic differentiation between “commercial” and “industrial” customers is in electricity usage or “load.” More specifically, load can be: a) the amount of energy used per hour, measured in kilo-watt (‘kWh”); or, b) the level of electricity demanded, measured in “kW”. Industrial customers require more electricity than commercial customers and therefore represent larger loads to be served by an electricity provider.

Definitions of commercial and industrial loads are not standard or universal. AE does not classify C-I customers using the same exact definition as CPS Energy, Oncor or other electricity providers. Table 1, provided by AE, shows how AE’s C-I customers can be grouped by load size and the typical types of businesses or organizations that fall into each category.

Table 1 Austin Energy Commercial and Industrial Examples by kW					
COMMERCIAL SEGMENTATION					INDUSTRIAL
SMALL 10 – 100 kW	SMALL – MEDIUM 100 – 300 kW	MEDIUM 300 – 500 kW	MEDIUM – LARGE 500 – 1MW	LARGE 1 < 3MW	INDUSTRIAL 3MW & OVER
<ul style="list-style-type: none"> ▪ Office condos ▪ Small restaurant ▪ Auto repair ▪ Small retail ▪ Hair/nail salon ▪ Florist ▪ Day care ▪ Dentist office ▪ Gas station ▪ Fast food ▪ Bank ▪ Medium church ▪ Large pharmacy ▪ Large liquor store ▪ Day spa ▪ Auto parts 	<ul style="list-style-type: none"> ▪ Medium-large restaurant ▪ Private school ▪ Small hotel ▪ Small-medium office campus ▪ Radiological office ▪ Bakery ▪ Auto dealer ▪ Cabinet shop ▪ Distribution center ▪ Soup kitchen ▪ Fitness center ▪ Medium hotel ▪ Book store ▪ Elementary school 	<ul style="list-style-type: none"> ▪ Big box retail ▪ Large movie theater ▪ Large sporting goods ▪ Office complex ▪ Large electronics ▪ Large church ▪ Bio technology manufacturing ▪ Medium department store 	<ul style="list-style-type: none"> ▪ Large hotel ▪ Large grocery ▪ Residential high rise ▪ Retirement community ▪ High school ▪ Large department store ▪ Golf/country club 	<ul style="list-style-type: none"> ▪ Hospitals ▪ Medium manufacturing ▪ Regional HQ ▪ High rise office ▪ Large Commercial laundry 	<ul style="list-style-type: none"> ▪ Large data center ▪ Semi-conductor

Source: Austin Energy.

Electricity load groups such as those shown in Table 1 help to determine what rate a C-I customer will be charged for electricity. For the regulated utilities, like municipally-owned utilities, these rates are published as tariffs. Tariff terms are typically fixed and the same terms are available to any comparable customer. For AE, the base tariff has been fixed for nearly 17 years, while the fuel factor is typically adjusted annually. However, AE's fuel charge has remained the same since 2008. Thus, the best comparisons against AE's rates are offers of a fixed price and term.

In the competitive market, many factors figure in to what a customer will be charged (the bill) for the electricity used. Often times the electricity provider will negotiate with the customer to customize a package that is appropriate to that customer's unique characteristics and acceptable for both the electricity provider and the customer. Considerations that may impact this negotiation include the load, the load factor (a measure of the difference between average and maximum load demanded by the customer over some time period, often one month), the voltage level at which a customer takes service, the location of the point of delivery to the customer, and many other factors associated with the commercial terms of the agreement between customer and electricity provider.

Load factor is a key driver of electric rates in regulated territories and price offers in the competitive market. A high load factor customer, such as a grocery store with refrigeration that operates 24 hours per day seven days per week, may receive a lower price per kWh than a lower load factor customer because the utility's fixed costs are being spread over more kWh of output to serve this type of customer. An example of a lower load factor customer is an office building that uses most of its energy Monday through Friday from 8 AM to 5 PM. Utilities have traditionally built generation to meet the highest need on its system ("peak load or peak demand"). It is often expensive to serve a customer that has variable energy needs because generating resources built to serve peak load are typically higher cost resources and operate fewer hours of the year over which costs can be recovered. Both regulated utilities and competitive REPs will incur higher costs to serve low load factor customers.

Another distinction between commercial and industrial customers is the voltage at which they are served. Commercial customers frequently receive electric service via the distribution system while industrial customers may receive their electric service via the transmission system. The distribution system in Texas is defined to be a line that carries less than 69 kilovolts ("kV"). The distribution system is used to distribute power drawn from high-voltage transmission systems to end-use customers. Transmission service is carried over lines with voltages at 69 kV and higher. Industrial customers who receive transmission service frequently own the step-down transformer, meaning that the TDSP incurs lower costs to serve transmission level customers. This cost difference is frequently reflected in the rate charged.

Commercial and Industrial customer classifications vary with each electricity provider. For this report, we have standardized customer classifications by adopting the characteristics shown in the comparison tables. For all comparison tables, starting with Table 5, R. W. Beck has chosen to use 16 load/size factor combinations. These tables show a variety of customer sizes, from as small as a 10 kW commercial load to an extremely large 25 MW customer. These tables also

show that we estimated prices for two different load factors for each load level. These different load factors are important because the load factor differentiates one dimension in the costs of providing service to a customer—whether the customer has a predictable, steady load level, or whether the customer has a highly variable load level, and is therefore more expensive to serve. Though we report comparative results for each of these 16 combinations of load and load factor, R. W. Beck cannot emphasize enough that the particular characteristics of each customer will dictate what type of service contract is appropriate for a customer. Only customers with a high risk tolerance for potentially highly volatile prices and billings (and in some cases, the willingness to drop load if prices rise too high) are good candidates for taking service under an MCPE contract. With that caveat, R. W. Beck reports results for each of these classifications to aid in comparison across regions and companies.

The pricing features described herein make comparing customer bills across Texas quite complicated. For this study, R. W. Beck started with AE's groupings for C-I customers and sought to match customer bill information for other providers, either reported or calculated, with AE's C-I customer categories. The comparative information consists of calculated bills representative of customers in the targeted study cities and information derived from applicable published utility and industry information.

Benchmarked Service Providers

The R. W. Beck team conducted a comparison of calculated AE customer electricity bills with calculated customer electricity bills in selected non-competitive communities across the state and estimated customer electricity bills for the four largest TDSP service territories where REPs compete to serve customers. In the non-competitive areas, the electric utilities serving the selected cities included municipally owned utilities, cooperative utilities, and one investor-owned utility.

Table 2 displays the city/metropolitan areas included in our analysis and the corresponding utility provider or TDSP in competitive market areas of Texas. TDSPs provide transmission and distribution service in specific geographic territories while REPs tend to serve a much larger area than one city and/or geographic market and may serve customers in numerous geographic areas. Thus an offer of a REP in one area may not be indicative of an offer from that same REP in a different TDSP territory.

City	Electric Service Provider or Territory
Abilene	AEP Texas North [formerly West Texas Utilities]
Austin	Austin Energy (AE)
Beaumont	Entergy Texas
Brownsville	Brownsville Public Utility Board (BPUB)
Cedar Park	Pedernales Electric Cooperative (PEC)
Corpus Christi	AEP Texas Central [formerly Central Power & Light]
Dallas	Oncor [formerly TXU]
Elgin	Bluebonnet Electric Cooperative (BEC)
Houston	Center Point Energy [formerly Reliant Energy Houston Light & Power]
New Braunfels	New Braunfels Utilities (NBU)
San Antonio	CPS Energy
San Marcos	City of San Marcos Utility Service (San Marcos)

Components of an Electricity Bill in a Competitive Territory

There are many components of an electric bill in competitive areas of ERCOT. Based on the manner in which the REP chooses to contract with and bill the customer, these different components may not always be apparent to the customer. REPs serving customers incur at least two distinct charges: Energy charges for generating the energy used by the customer and TDSP (or wires) charges for delivery of this energy to the customer. For commercial and industrial customers these two charges are typically split into separate billing components with the TDSP (or wires) charges being passed through to the customer on an as billed basis from the distribution service provider and the energy charged based on contract terms between the REP and the customer.

The energy charge typically includes a number of cost components incurred by the REP to provide energy to the customer. Typically the costs paid to the generation company or energy marketer for the energy produced to serve the customer’s need is the largest cost component in the energy charge.

Congestion is a key component in every electric bill, either as an explicit cost component or included as part of the energy charge. ERCOT manages congestion across the transmission network and assigns the costs of congestion to retail service providers according to formulas in

the ERCOT Protocols⁶. As ERCOT assigns congestion charges to an electricity provider, that provider will undoubtedly pass that cost along to the customer in the customer's bill. For customers paying a fixed price per kWh for all energy delivered, such as residential customers, the seller must anticipate (or forecast) the potential for congestion charges and include them in the total price per kWh charged the customer. The REP will include a congestion premium embedded in the retail price based on the REP's forecast for congestion at a particular location. For longer term offers, there will be more uncertainty in the REP's forecast, so a longer term price offer will likely be higher than a comparable shorter term offer reflecting the additional risk premium. For customers who pay on a variable basis, congestion charges can be reflected in the energy rate or as an additional charge passed through from ERCOT—depending upon the terms of service under an individual contract. In the extreme case, where a customer pays for electricity on an MCPE basis, the costs of the REP are driven less by the accuracy of its congestion forecast, thus the REP will add a lesser risk premium, typically resulting in a lower *average* price under such a contract.

In addition to congestion fees, other ERCOT associated fees in the current zonal market include the ERCOT system maintenance fee and the nodal surcharge. These fees are assigned to all retail loads on a dollar per MWh fee basis.⁷ These fees will continue to be charged in the nodal market design and will be the same for all customers in ERCOT. Thus, there is no differentiation in these costs between competitive markets and traditional bundled utility markets in ERCOT.

Each REP also incurs costs for provision of ancillary services. Ancillary services are reserves that assure the reliability of the electric network. Every REP in ERCOT, either competitive or regulated, is required under ERCOT rules to provide certain types of reserves or to procure those reserves through the ERCOT ancillary services market. Price offerings from one REP to another will differ based on each REP's success in managing its ancillary services costs.

Also included in the energy charge are other charges that REPs incur in providing retail electric service to customers including their representative share of transmission system losses that inherently occur when transporting energy from the production source to the various usage points as well as fees to Qualified Scheduling Entities ("QSEs") to provide scheduling services and to financially settle with ERCOT for the costs of any special services provided by ERCOT.

Other pricing components may apply depending on the type of contract arrangement executed between the electricity provider and the customer. Electricity product offerings developed by electric providers for commercial and industrial customers may also take into account the customer's risk tolerance. For example, a risk adverse customer may be offered a fixed rate per kWh for any amount of usage, while another customer that is more risk tolerant may opt for an indexed rate where price is determined by the market every hour.

⁶ The ERCOT Protocols are the 1,000 plus page rulebook under which the ERCOT transmission grid and market systems operate. Under State law, compliance with the ERCOT Protocols is mandatory and enforceable by civil penalties.

⁷ The ERCOT nodal surcharge is collected by ERCOT from generators; however, it is generally accepted that generators pass through the nodal surcharge to REPs.

Methodology and Data for Competitive Market Estimates

R. W. Beck cannot emphasize enough in this report that in the competitive areas of Texas energy service is provided via private contracts that most often contain confidentiality provisions, binding both the seller and buyer to non-disclosure of key terms of the contract, such as energy pricing. For this reason, gathering actual bills and contract provisions to develop estimated bills is extremely difficult and time consuming and ultimately may not be representative of actual energy prices in the broader market. In addition, as offers from REPs are based on current market conditions and forecasts of market prices and congestion, a supply offer on any one day may not be valid or representative at a later time. Therefore, it was incumbent on the R. W. Beck team to adopt reasonable approaches to estimating and calculating representative bills in those competitive areas of the state. To calculate energy charges, the R. W. Beck team utilized methods similar to those used by REPs and wholesale energy providers to develop offers to customers. Non-energy related charges, such as T&D charges were estimated using the most current tariffs of the T&D service providers in the appropriate area.

The results reported below are estimates based on the methodologies described in this section. As these are estimates, it is important to provide validation of the estimates. Providing such validation is challenging for the same reason that the estimates are required. Comprehensive retail market information is not available. Later in this report, R. W. Beck will look to a set of publicly available data maintained by the Department of Energy's Energy Information Administration to assess and validate these estimates.

The following sections further describe the approaches used to conduct the comparative analysis and present the estimated bills developed using each approach.

Heat Rate Methodology

The Heat Rate method uses natural gas prices as the variable to track changes in energy prices over time. A representative heat rate factor is multiplied by an appropriate set of natural gas prices to determine energy costs at an assumed usage level. The natural gas prices utilized were taken from actual New York Mercantile Exchange ("NYMEX") natural gas futures closing prices realized in late 2008 for assumed deliveries in 2009. Next TDSP charges are calculated for this usage level and added to energy charges to achieve a total bill for electric service.

The Heat Rate method uses natural gas prices as the variable to track changes in energy prices over time. A representative heat rate factor is multiplied by an appropriate set of natural gas prices to determine energy costs at an assumed usage level. Next TDSP charges are calculated for this usage level and added to energy charges to achieve a total bill for electric service. The Heat Rate methodology is an approach to pricing used in many energy contracts, especially in markets where natural gas-fired generators are common, as they are across the ERCOT system. The heat rate method calculates a price of energy by multiplying the price of natural gas by a fixed factor, often called a heat rate.

Sometimes an additional pricing adder is applied to the equation to represent the costs of congestion, ancillary service, marketing, and other ERCOT fees. Using an additional adder

allows a seller to offer a lower heat rate to the end user while still maintaining a market price for energy.

Heat rate contracts can be offered as variable price contracts where the price varies over some agreed upon interval with the price of natural gas. Alternatively, heat rate contracts can be structured as fixed-price contracts. If the customer wants to convert to a fixed electric price the REP will often offer to purchase natural gas futures contracts which will fix the future price of gas used to calculate the energy price and thus lock-in a future price of energy under the contract. As a result, the pricing in a heat rate contract may differ from interval to interval based on a REP's natural gas price forecast. The ability to lock in a future price of energy at any time during the term of the contract makes the Heat Rate Pricing approach commonly used by customers desiring a fixed price for future energy deliveries. If energy prices are not where the customer wants them to be at the time of contracting the customer can use spot natural gas prices to set the energy price under the contract until natural gas futures prices are at a point that produces an acceptable energy price to the customer. At this time the REP can purchase natural gas futures and lock in their future energy price under the heat rate contract. Heat rates used in energy contracts will vary somewhat based on the location, energy usage and the usage pattern of the end-use customer.

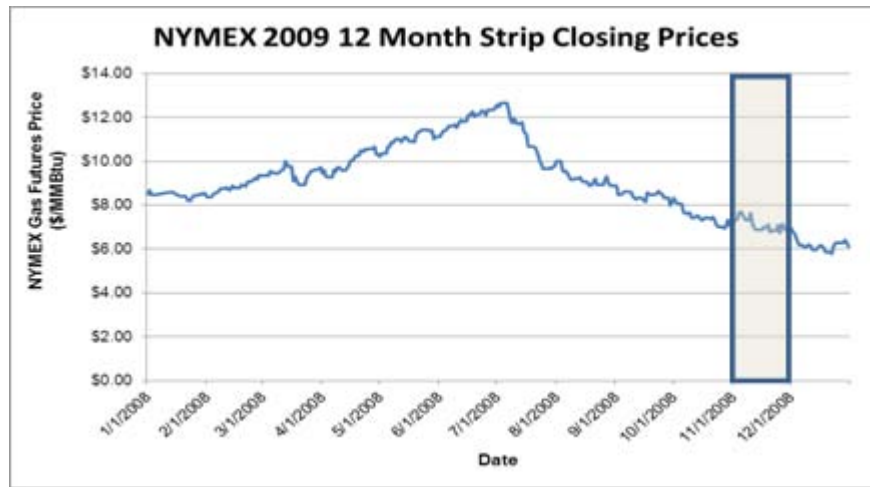
Heat Rate Methodology Analysis Approach

For this analysis, Heat Rate factors were estimated for various sized customers at various assumed usage levels using the R. W. Beck team's historic knowledge of market pricing for customers in the various competitive zonal sub-markets in ERCOT. Zonal energy price differences were accounted for using the average difference in zonal MCPE prices in 2009. The range of heat rate factors used in the R. W. Beck team's analysis varied between a low of 9.4 to a high of 12.0. It is important to remember that these heat rate factors are for retail energy delivered to the distribution utility and include all potential energy charges including ancillary services, losses, ERCOT fees, QSE fees, load following costs, and all REP charges. For larger high load factor customers or constant usage power purchases, heat rates will be lower than for low load factor and smaller customers that will typically have fewer units of energy usage to spread costs over. It is also important to keep in mind that R. W. Beck's approach did not utilize any price adders in addition to the Heat Rate factor. All cost recovery is included in the Heat Rate factor with the exception of the zonal energy price differentials which are derived from the differences in the annual average MCPE price for the zone in 2009. Using the North zone as the reference zone, the zonal price differentials used are \$0.003 per kWh for the South zone and Houston zone and (\$0.004) per kWh for the West zone.

Development of Fixed Energy Price

Since many heat rate-based customers ultimately want a fixed price for energy, the R.W. Beck team multiplied the assumed heat rate by historic NYMEX natural gas futures prices for 2009 delivery to determine a cost of energy. In determining the appropriate NYMEX natural gas futures prices to use, the R. W. Beck team was sensitive to the volatility natural gas futures prices prior in 2008, as shown by the chart below.

**Figure 4:
Natural Gas Future Prices**



R. W. Beck assumed that, given the declining nature of the natural gas market in the second half of 2008, a wise customer would wait for as long as reasonably possible to contract for 2009 delivered energy, but still allow enough time to ensure a contract was executed prior to the start of the year. Thus, R. W. Beck utilized a gas price based on the average of NYMEX 2009 natural gas futures prices realized during November 2008 (as shown on the shaded area of the above graph) as our estimate natural gas futures prices used to fix future energy prices.

For purposes of this approach no additional adders were utilized. Once the energy rates were estimated, TDSP charges were calculated for the assumed demand and energy usage of the customer and these costs were added to the calculated energy charges to achieve an estimated total bill. This could be a normal purchasing approach for an energy customer desiring a fixed price in the competitive market.

Table 3 below compares bills in AE’s territory for each of the 16 load size and load factor classifications with the average estimated bill for 2009 in the four TDSP markets in Texas using the heat rate method. It is important to remember that the prices shown in Table 3 are for calendar year 2009 and are based on market conditions present and energy prices available at that that time. Given recent energy market price declines in 2009 through 2010, currently prices would probably be lower than the historic estimates presented below.

**Table 3
AE Bill Comparison to Calculated Heat Rate Bills - Average for 2009**

	Austin Energy (per Tariff) ¹	Houston (Center Point Energy)	Dallas (Oncor)	Corpus (AEP Texas Central)	Abilene (AEP Texas North)
10 kW					
20% Load Factor	\$140	\$220	\$171	\$195	\$184
60% Load Factor	409	412	425	500	457
35 kW					
30% Load Factor	876	861	618	954	618
60% Load Factor	1,285	1,340	1,067	1,567	1,201
100 kW					
40% Load Factor	2,926	3,009	2,872	3,367	2,710
80% Load Factor	4,519	4,887	4,614	5,203	4,335
300 kW					
40% Load Factor	7,878	8,791	8,462	9,801	7,740
80% Load Factor	12,275	14,426	13,689	15,297	12,614
500 kW					
40% Load Factor	13,131	14,920	14,053	16,232	12,769
80% Load Factor	20,459	23,786	22,763	25,391	20,893
2.50 MW					
40% Load Factor	65,401	74,090	69,653	80,535	63,069
80% Load Factor	101,790	118,417	113,503	126,331	103,687
5 MW					
40% Load Factor	125,229	147,980	110,131	160,914	125,943
80% Load Factor	190,608	236,634	196,297	252,507	207,179
25 MW					
40% Load Factor	616,978	739,104	698,832	803,944	629,937
80% Load Factor	988,539	1,182,373	1,134,337	1,262,178	1,035,118

Source: AE Tariffs and calculated Heat Rate Prices using a gas price of \$7.136/MMBtu

^{Note}1 AE electricity bills were calculated as follows: 10 kW bills based on General Service Non-demand (EO2); 35 kW and 100 kW bills were calculated at General Service Demand (EO6) rates; 300 kW, 500 kW and 2.5 MW bills were calculated at Primary Service (EO7) rates; 5 MW bills were calculated based on Large Primary Service Special Contract Rider Time-Of-Use (LTC 2/3) and 25 MW bills were calculated based on Large Primary Service Special Contract Rider Time-Of-Use (LTC 2/3) and the Large Primary Service Special Contract - Industrial Rider Time-Of-Use (LIR 1). Fuel adjustment factor = \$0.03653/kWh. Primary fuel adjustment factor = \$0.03544/kWh.

Table 3 suggests that based on the methodology and data used here, AE's C-I bills are comparable with C-I rates in competitive territories. The estimates indicate that AE's bills are most competitive for the largest-sized customers. AE's bills also appear to be more competitive for customers with higher load factors than the comparably sized customers at lower load factors. This could be the result of a policy or organizational objective to create incentives rewarding customers with higher load factors.

Each of these four cities in Table 3 is served by a separate T&D service provider that has its own unique tariff and set of rates. These different tariffs for wires services account for some of the differences across the different zones. AE also has unique rates for its wires services, though these are currently bundled in AE's whole rate, and therefore cannot be isolated from its bundled bill. In addition, it is important to note that each of the four comparison cities are located in separate ERCOT congestion zones or sub-markets, each of which may have its own unique cost of energy at any point in time based on the mix of generation assets in that zone and current or future anticipated cost of congestion between zones. As AE's service territory is in the ERCOT South Zone, the most appropriate comparison for AE is to focus on the results for other cities/service territories in the South Zone, which in Table 3 is Corpus Christi/AEP Texas. AE's electricity bills, based on tariffs, are generally lower than electricity bills calculated for Corpus Christi.

The results in Table 3 show that electricity bills for AE's C-I customers appear competitive with C-I customers in competitive territories served on fixed-priced contracts. Nevertheless, readers should be cautious when interpreting these comparisons. The results are based on estimates using assumptions about heat rates and forward prices for natural gas for an historic period. These estimates should be considered indicative only of a specific contract for a specific assumed customer. Each individual C-I customer's bill may differ from those in the table due to difference in customer load, load factor, voltage at which service is received, length of term that the contract is fixed, generation resource mix of the energy supplier, and other specific characteristics of what an actual contract agreement might contain. Additionally, current estimates may be somewhat more favorable in the competitive territories due to the recent price declines in both the natural gas market and the ERCOT electric market.

Market Clearing Price for Energy Methodology

ERCOT procures energy to balance the overall energy market every 15 minutes. ERCOT allows QSEs to utilize the balancing energy market as a supply resource. Balancing energy is procured on a market clearing basis by zone, meaning that the bid price of the highest (last) offer accepted by ERCOT will be the price paid for all offers accepted. Thus, every 15 minutes there is a new MCPE within each ERCOT zone. These markets are often available to customers via MCPE-based price offerings from REPs. These 15 minute interval prices at times may exhibit volatility with an ERCOT-established maximum price of \$2,250 per MWh (or \$2.25 per kWh) for energy. Energy supply based on a variable rate tied to MCPE are favored by larger customers who have sufficient cash reserves to accommodate significant volatility in their electric billings, or can afford to curtail usage on very short notice. As a customer taking service under these terms assumes pricing risk of as much as \$2.25 per kWh, a customer taking service under these terms must be capable of managing that risk. MCPE volatility is illustrated in the data provided in Table 4.

Table 4
Range of Average Hourly Market Clearing Energy Prices by Month and Zone (\$/MWh)

Month	Year	Max Hour North	Max Hour South	Max Hour West	Max Hour Houston	Min Hour North	Min Hour South	Min Hour West	Min Hour Houston
Jan	2009	\$ 648.68	\$1,060.24	\$ 210.29	\$ 626.28	\$ 1.13	\$ 1.13	\$ (34.97)	\$ 1.13
Feb	2009	\$1,039.03	\$ 952.87	\$ 156.33	\$ 982.62	\$ 2.20	\$ 2.20	\$ (90.91)	\$ 2.20
Mar	2009	\$1,700.89	\$ 584.34	\$1,664.26	\$ 640.42	\$ (15.62)	\$ (21.00)	\$(235.38)	\$ (15.62)
Apr	2009	\$ 496.95	\$ 450.26	\$ 279.81	\$ 465.69	\$ (24.49)	\$ (24.49)	\$ (35.72)	\$ (24.49)
May	2009	\$ 584.10	\$ 552.87	\$ 439.84	\$ 565.78	\$ 1.13	\$ 1.13	\$ (35.66)	\$ 1.13
Jun	2009	\$ 200.23	\$2,115.26	\$ 256.08	\$ 1,203.26	\$ (3.48)	\$ (3.48)	\$ (34.84)	\$ (3.48)
July	2009	\$ 377.29	\$ 377.29	\$ 377.29	\$ 377.29	\$ 13.66	\$ 13.66	\$ (29.90)	\$ 13.66
Aug	2009	\$ 331.15	\$ 331.15	\$ 331.15	\$ 460.99	\$ 11.69	\$ 11.69	\$ (30.15)	\$ 11.69
Sept	2009	\$ 566.43	\$1,295.17	\$ 339.09	\$ 1,803.67	\$ 10.91	\$ 10.91	\$ (32.79)	\$ 10.91
Oct	2009	\$ 415.21	\$ 415.21	\$ 415.21	\$ 519.75	\$ 0.65	\$ 0.65	\$ (22.89)	\$ 0.65
Nov	2009	\$ 228.91	\$ 228.91	\$ 228.91	\$ 228.91	\$ (7.63)	\$ (7.63)	\$ (7.63)	\$ (7.63)
Dec	2009	\$ 282.94	\$ 282.94	\$ 282.94	\$ 282.94	\$ (18.87)	\$ (18.87)	\$ (28.51)	\$ (18.87)
Jan	2010	\$ 233.82	\$ 670.81	\$ 233.82	\$ 417.83	\$ 14.90	\$ 14.90	\$ (29.50)	\$ 14.90
Feb	2010	\$1,259.74	\$1,256.04	\$ 395.46	\$ 1,257.91	\$ 13.67	\$ 13.67	\$ (24.71)	\$ 13.67
Mar	2010	\$ 587.67	\$ 586.33	\$ 434.47	\$ 587.02	\$ (13.01)	\$ (13.08)	\$ (31.57)	\$ (13.04)
Apr	2010	\$ 333.76	\$ 333.76	\$ 333.76	\$ 333.76	\$ (0.95)	\$ (2.17)	\$ (30.18)	\$ (1.51)
May	2010	\$ 538.84	\$ 538.84	\$ 538.84	\$ 538.84	\$ (21.03)	\$ (21.03)	\$ (21.03)	\$ (21.03)
Jun	2010	\$ 316.28	\$ 316.28	\$ 316.28	\$ 316.28	\$ 5.16	\$ 5.16	\$ (30.23)	\$ 5.16
July	2010	\$ 294.31	\$ 347.57	\$ 266.70	\$ 491.68	\$ 16.63	\$ 15.74	\$ (1.76)	\$ 16.20

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For this analysis, R. W. Beck used historic MCPE data obtained from ERCOT to compute average daily on-peak and off-peak prices. An example of the ERCOT information used to calculate the MCPE monthly bills is attached as Exhibit 1. Average daily pricing was then used to calculate average monthly energy pricing. Sometimes an additional adder is applied by the retail electricity provider to the market price, and in this analysis we included a \$0.012 per kWh adder to the reported market price to cover the many other costs and charges incurred by the REP to provide energy service to the customer. These costs were mentioned earlier in this report and include provision of ancillary services, system losses, and ERCOT fees and charges as well as REP costs such as administrative costs, billing costs, scheduling costs, and REP profit margin. These fees may vary from REP to REP and can change based on overall market conditions and the cost the REP incurs to obtain these services. R. W. Beck's estimate is based on historic experience and market expertise. Once the energy rates were estimated, TDSP charges at the assumed demand and load factor were added to the calculated energy charges to achieve an estimated total monthly bill. Finally, a yearly average bill was calculated at both On-peak and Off-peak pricing.

Table 5 compares estimated AE electricity bills with electricity bills developed for other utilities using the MCPE methodology. The table shows the calculated average monthly price at select demand levels and load factors based on actual market clearing prices for 2009. On average, the electricity bills estimated using the MCPE methodology are lower than the electricity bills using the heat rate methodology. This result is expected because by taking service on an MCPE basis, the customer is taking on risk that would otherwise be incurred by the REP or mitigated through some type of market instrument. Companies taking service under a variable MCPE-based rate are likely to hedge the risk themselves or be willing to interrupt service should prices exceed an agreed upon threshold.

As discussed in the section on using the heat rate method, it is important to note the differences in prices between the four zones in ERCOT. Each of the four cities analyzed in ERCOT's competitive market areas resides in a different congestion zone. Each zone has a different set of unique generators that lie within that zone as well as a unique MCPE price for balancing energy. Moving generation produced in one zone to a load or end-user located in another zone can be subject to congestion fees that increase the cost of energy. As such, from a pricing perspective, each zone can be thought of as a unique dynamically priced sub-market of its own. This is particularly true in the West zone, which has experienced an unprecedented increase in the amount of wind generation in recent years. Historically, the electric transmission system has lacked the transfer capacity to move this wind generation out of the sparsely populated West zone into more populated zones with higher electricity demands. This wind generation has been somewhat "landlocked" creating an overabundance of supply in the West zone and creating abnormally low energy prices in this zone. Austin resides in the ERCOT South Zone and its pricing is best compared to providers within that zone. The South Zone also includes the Corpus/AEP Texas Central market. Energy prices available in other ERCOT congestion zones may not be available in the South zone in which Austin resides.

AE does not today offer its customers the option to take power at a variable rate comparable to the variable rate plans available to C-I customers in competitive territories. Variable rates can be

advantageous when the supply of energy is significantly greater than demand for energy. Thus, it is expected that when comparing historic MCPE-based bills, which would typically be offered on a variable basis to customers, against AE's fixed tariffs, the MCPE-based bills will be lower than AE's. Should AE at some time in the future offer a comparable variable rate plan, a customer should anticipate a more volatile bill than under the comparable tariff, as that plan will shift market risk from AE to the customer. When supply significantly exceeds demand, the customer can expect the possibility of a lower bill than under a longer term fixed price options. When energy supplies are not so plentiful, the customer can expect the possibility of a higher bill than under a longer term fixed price option.

**Table 5
AE Bill Comparison to Calculated Market Clearing Price of Energy Bills – Average for 2009**

	Austin Energy (per Tariff) ¹	Houston (Center Point Energy)		Dallas (Oncor)		Corpus (AEP Texas Central)		Abilene (AEP Texas North)	
		On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
10 kW									
20% Load Factor	\$140	\$161	\$145	\$111	\$97	\$137	\$118	\$125	\$109
60% Load Factor	409	306	257	317	276	396	340	352	302
35 kW									
30% Load Factor	876	590	505	592	521	688	590	507	421
60% Load Factor	1,285	969	798	941	799	1,204	1,008	832	660
100 kW									
40% Load Factor	2,926	2088	1762	1,980	1,710	2,504	2,131	1,836	1,508
80% Load Factor	4,519	3534	2883	3,308	2,769	3,957	3,210	3,067	2,411
300 kW									
40% Load Factor	7,878	6,029	5,051	5,784	4,975	7,214	6,093	5,119	4,135
80% Load Factor	12,275	10,367	8,412	9,769	8,151	11,561	9,317	8,811	6,843
500 kW									
40% Load Factor	13,131	10,317	8,687	9,588	8,240	11,920	10,050	8,402	6,763
80% Load Factor	20,459	17,022	13,762	16,231	13,534	19,164	15,425	14,555	11,276
2.50 MW									
40% Load Factor	65,401	51,074	42,926	47,632	40,890	58,976	49,629	41,233	33,035
80% Load Factor	101,790	84,597	68,301	80,844	67,359	95,196	76,503	71,997	55,601
5 MW									
40% Load Factor	125,229	101,949	85,653	95,187	81,702	117,796	99,103	82,272	65,875
80% Load Factor	190,608	168,995	136,403	161,611	134,641	190,237	152,850	143,800	111,008
25 MW									
40% Load Factor	616,978	508,947	427,467	475,627	408,202	588,359	494,892	410,579	328,598
80% Load Factor	988,539	844,178	681,218	807,748	672,897	950,563	763,627	718,223	554,260

Source: AE Tariffs and Table 5 – Market Clearing Price

¹See footnote for Table 3.

As stated in describing Table 5, we expected the MCPE methodology would produce the lowest electricity bill calculation based on the historical analysis conducted for the competitive ERCOT market. It follows that AE’s electricity bills based on current tariffs will be higher than electricity bills calculated for other providers using the MCPE methodology.

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Data Comparisons Using Publicly Available Data

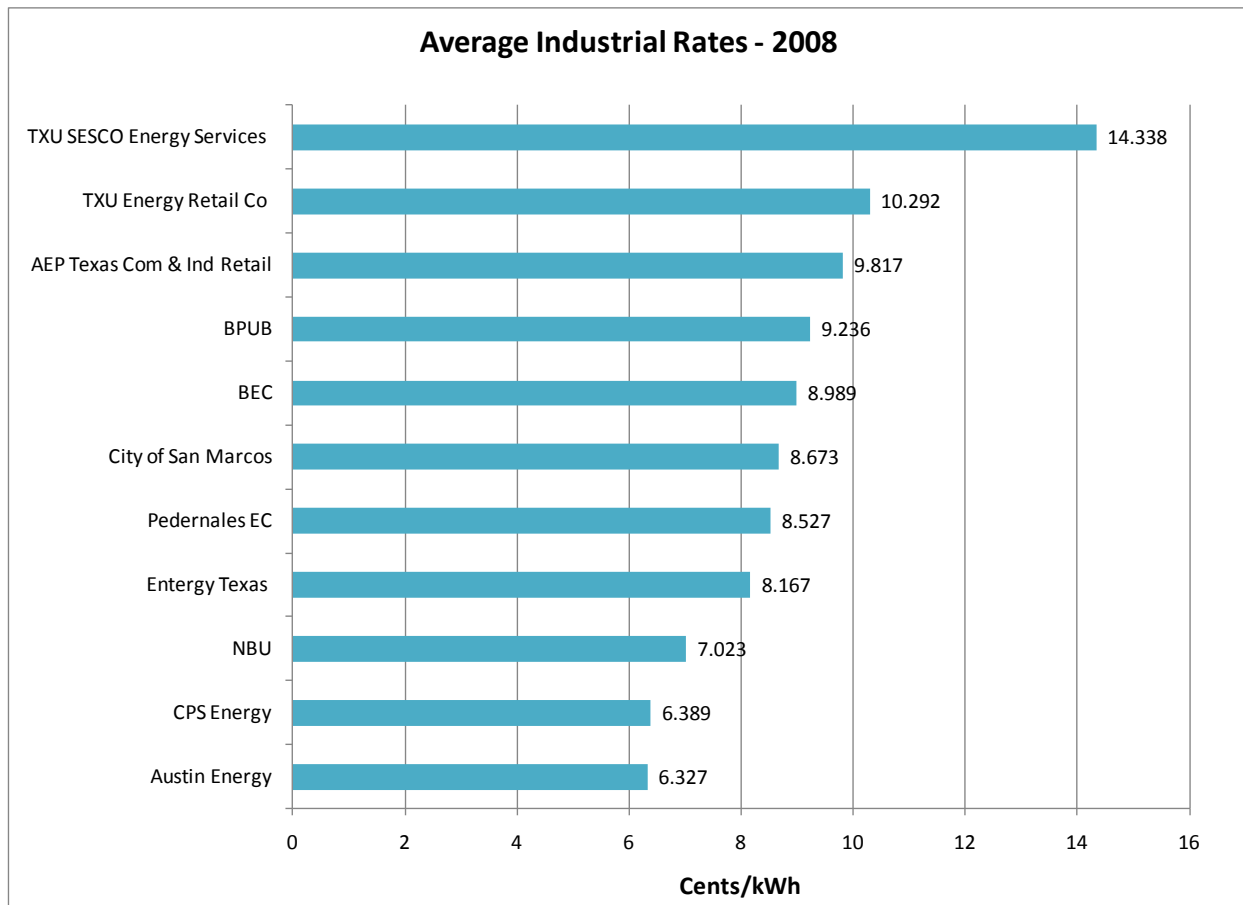
Energy Information Administration

The R. W. Beck team also considered publicly available data to provide additional sources to estimate billings and serve as a reasonableness check on data developed using other approaches. While there is no comprehensive data set available for such a comparison, one such source is the Department of Energy's Energy Information Administration ("DOE-EIA") pricing data which is based on self-reporting by utilities. This DOE-EIA data cannot be used to estimate electricity bills for specific customer classifications of load and load factor. These data are self-reported by utilities at an aggregated level, so only provider-by-provider averages can be used, and even those comparisons should be conducted carefully. The data are based on each utility's internal classification of customers. DOE-EIA guidance states that the commercial data should reflect "electric energy supplied for commercial purposes" and industrial data should reflect "electric energy supplied for industrial purposes."

The DOE-EIA provides independent statistics and analysis of the energy industry in the United States. Through its Forms EIA-861 "Annual Electric Power Industry Report" and EIA-826 "Monthly Electric Utility Sales and Revenue Data" the DOE-EIA collects data such as peak load, generation, electric purchases, sales, revenues, customer counts from electric utilities, wholesale power marketers (registered with the Federal Energy Regulatory Commission), energy service providers (registered with the States), and electric power producers. Form EIA 861 provides data from a comprehensive group of utilities and retail providers; however the most recent data available are for calendar year 2008. As such, these data do not provide a means to determine whether declines in natural gas prices that have occurred after the 2008 time period have resulted in lower commercial and industrial rates as reported to EIA.

Form EIA-826 is used to collect retail sales of electricity and associated revenue each month from information reported by a limited number of electric utilities that participate in the Form EIA-861 reporting. This information is timelier; but draws from a much smaller group of utilities and retail providers. For 2010 the only utilities selected for this study who reported the Form EIA-861 were CPS Energy and Entergy Texas.

**Figure 5:
Average Industrial Rates**

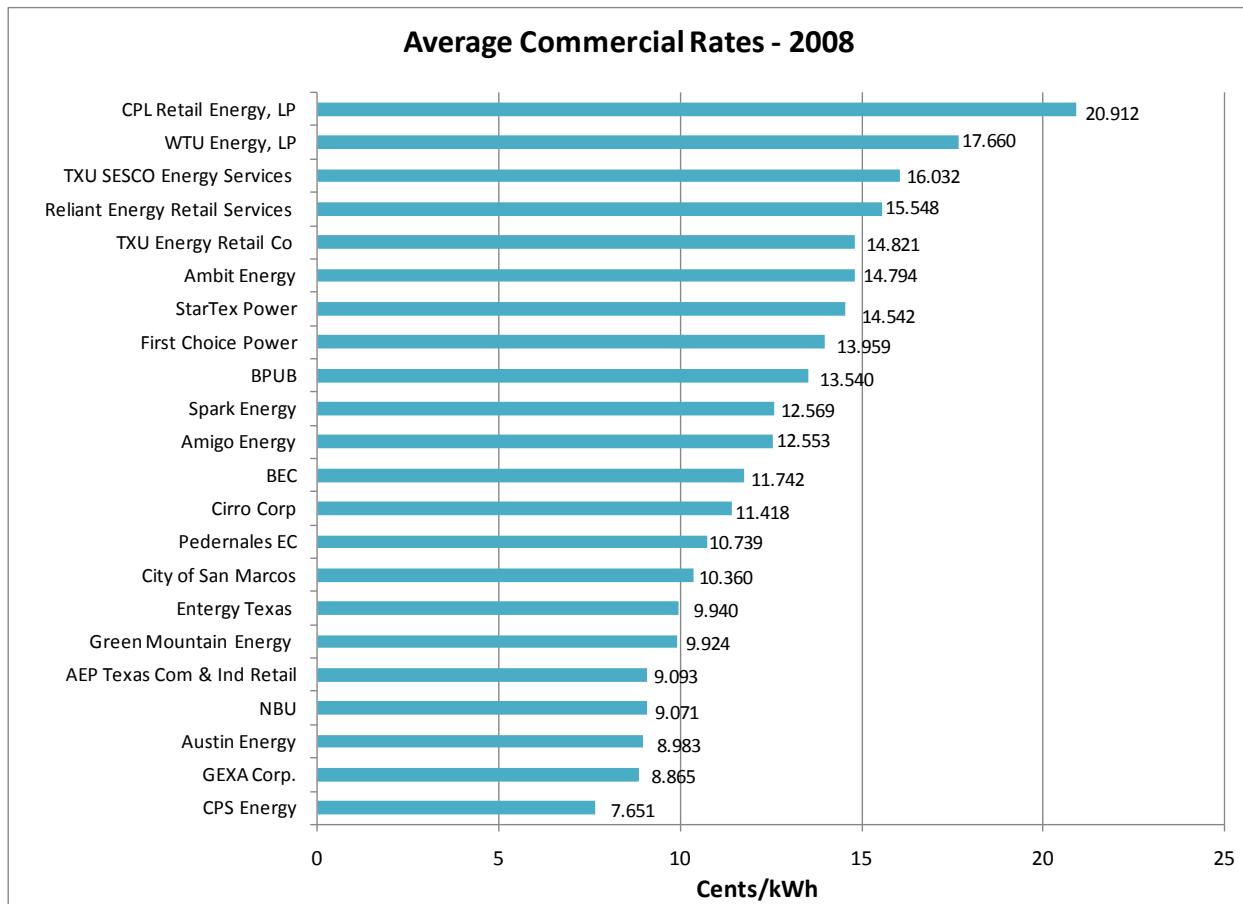


Source: EIA Form 861 - 2008 www.eia.doe.gov/cneaf/electricity/page/eia861.html

Note: Data for all REPs and Non-Opt In Entities (“NOIEs”) is not available from EIA.

In Figures 5 and 6, R. W. Beck used the data elements from the "Annual Electric Power Industry Report" for 2008 to calculate an average price for kWh for all customers classified as industrial (Figure 5) and commercial (Figure 6). This DOE-EIA based data cannot be used to calculate electricity bills or comparisons of those bills, only high level averages for each utility or REP. As reported in Form 861 and illustrated in Figure 5, 2008 average industrial customer rates in Texas ranged from approximately 6 cents per kWh to about 14 cents. AE and CPS Energy rates were among the lowest in the ERCOT area at 6.33 cents and 6.39 cents, respectively. Note, these results are for 2008, prior to the recent decline in natural gas prices. Due to that decline, we expect to see lower average industrial and commercial rates in 2009 and 2010 for many providers, particularly in competitive territories.

**Figure 6:
Average Commercial Rates**



Source: EIA Form 861 – 2008 www.eia.doe.gov/cneaf/electricity/page/eia861.html

Note: Data for all REPs and NOIEs is not available from EIA.

In 2008, average commercial customer rates in Texas ranged from approximately 7.5 cents per kWh to just over 20 cents. Again, Austin Energy and CPS Energy rates were the lowest in the ERCOT area, at 7.65 cents and 8.98 cents, respectively, as shown in Figure 6.

Public Utility Commission of Texas Data

The Electric Division of the PUCT provides a commercial monthly electric bill comparison based on data collected from various utilities in markets within Texas that are not yet open to competition (<http://www.puc.state.tx.us/electric/rates/NCrate/index.cfm>). The data is limited to utilities who participate in the survey and computations are provided by each participating utility; hence this analysis was limited to available data and is self-reported without any form of validation. Each utility calculates a typical customer's bill for a total of eight demand/kWh levels based on their internal rate tariff.⁸ Of the providers covered in this report, AE, CPS

⁸ Public Utility Commission of Texas. <http://www.puc.state.tx.us/electric/rates/NCrate/rclass.cfm>. The PUCT provides the following disclaimer, "This is information is compiled by the PUCT from publicly available information

Energy, City of San Marcos and Entergy Texas participate in the PUCT survey; however, details regarding the specific tariffs used to generate this information are not provided. These results are shown in Table 6 under the columns labeled PUCT Survey.

Table 6 also compares calculated AE commercial and industrial customer electricity bills using the published tariff to the 2009 bill information published by the PUCT.

Table 6 AE Bill Comparison to PUCT Monthly Average Commercial and Industrial Bills - 2009				
	PUCT Survey			
	Austin Energy	CPS Energy	Entergy Texas	City of San Marcos
35 kW				
7,500 kWh	\$876	\$692	\$691	\$672
15,000 kWh	\$1,285	\$1,132	\$1,195	\$1,324
300 kW				
87,000 kWh	\$7,878	NA	\$6,921	\$7,872
174,000 kWh	\$12,275	NA	\$11,815	\$14,709
500 kW				
145,000 kWh	\$13,131	NA	\$11,510	\$13,270
290,000 kWh	\$20,459	NA	\$19,425	\$24,389
2,500 kW				
720,000 kWh	\$65,401	NA	\$57,112	\$63,165
1,440,000 kWh	\$101,790	NA	\$99,141	\$118,379

Source: AE Tariffs and Public Utilities Commission of Texas; Commercial Bill Comparisons for Non-Competitive Markets; <http://www.puc.state.tx.us/electric/rates/NCrate/index.cfm>. Represents the average of 12 months.

Note: AE electricity bills were calculated as follows; 35 kW bills were calculated at General Service Demand (EO6) rates at 7,500 and 15,000 kWh; 300 kW (calculated at 87,000 and 174,000 kWh), 500 kW (calculated at 145,000 and 290,000 kWh) and 2.5 MW (calculated at 720,000 and 1,440,000 kWh) bills were calculated using Primary Service (EO7) rate. Fuel adjustment factor = \$0.03653/ kWh. Primary fuel adjustment factor = \$0.03544/kWh.

Table 7 also compares calculated AE commercial and industrial customer electricity bills using the published tariff to the 2010 bill information published by the PUCT.

from the REPs and PUCT approved price to beat rates (through December 2006) using representative usage levels. The PUCT makes no recommendation with respect to any REP. Although we believe these prices are accurate, the PUCT makes no warranty that the prices in this table are currently being offered.”

Table 7
AE Bill Comparison to PUCT
Monthly Average Commercial & Industrial Bills – January Through July 2010

	PUCT Survey			
	Austin Energy	CPS Energy	Entergy Texas	City of San Marcos
35 kW				
7,500 kWh	\$872	\$714	\$634	\$648
15,000 kWh	\$1,281	\$1,159	\$1,077	\$1,275
300 kW				
87,000 kWh	\$7,857	NA	\$6,317	\$7,587
174,000 kWh	\$12,254	NA	\$10,224	\$14,139
500 kW				
145,000 kWh	\$13,095	NA	\$10,504	\$12,795
290,000 kWh	\$20,424	NA	\$16,768	\$23,440
2,500 kW				
720,000 kWh	\$65,225	NA	\$50,714	\$60,807
1,440,000 kWh	\$101,613	NA	\$103,219	\$113,665

Source: AE Tariffs and Public Utilities Commission of Texas; Commercial Bill Comparisons for Non-Competitive Markets; <http://www.puc.state.tx.us/electric/rates/NCrate/index.cfm>. Represents the average of 12 months.

Note: AE electric bills were calculated as follows; 35 kW bills were calculated at General Service Demand (EO6) rates at 7,500 and 15,000 kWh; 300 kW (calculated at 87,000 and 174,000 kWh), 500 kW (calculated at 145,000 and 290,000 kWh) and 2.5 MW (calculated at 720,000 and 1,440,000 kWh) bills were calculated using Primary Service (EO7) rate. Fuel adjustment factor = \$0.03653/kWh. Primary fuel adjustment factor = \$0.03544/kWh

Since AE applies a variety of tariffs to different types of commercial and industrial customers, differences between the R. W. Beck calculated price and the price reported by the PUCT may be due to R. W. Beck using a different rate schedule than the one reported by AE. For example, the R. W. Beck calculated price at 2.5 MW demand and 80 percent load factor relied on the General Service Demand rate (EO7). However, AE offers tariffs such as State General Service – Demand, Independent School District, Independent School District Time-of-Use, Co-incident Load Special Contract Rider tariffs that might also apply to a 2.5 MW load.

Electric Providers in Non-competitive Markets

For electric utility providers in non-competitive areas of Texas, published tariff rates were used to calculate a representative electricity bill for each of the 16 demand and load factor levels. This bill calculation included fixed charges such as a monthly service fee and all applicable variable costs, based on data availability.

Table 8 compares calculated AE commercial and industrial customer electricity bills to other electricity bills calculated using currently published public utility tariffs. Notes provided with Table 8 helps explain the particular tariff used to create electricity bills at each demand and load factor level. In instances where multiple rates might apply, the lowest resultant rate is shown in the table. For example, a Brownsville PUB customer with demand of 500 kW could be served by either the General Service Demand rate or the General Service Large Demand rate; representative electricity bills were calculated under both tariffs and the lowest resultant bill is displayed. Instances when multiple tariffs might apply are noted in the table.

As expected, electricity bills calculated using published tariffs from a selected group of electric cooperatives and municipal utilities exhibit considerable variability. Many factors come into consideration for these utilities in setting rates and tariffs. Factors include the service territory location within ERCOT, the strategic aspirations of the utility owners, power supply characteristics including fuel mix and age of assets, among others. The reader should also recognize that this comparison is a snapshot of one point in time or period of time and some utilities are in the process of changing tariffs which could ultimately change their comparative position within this group.

**Table 8
Monthly Commercial & Industrial Bills at Selected Demand Levels & Load Factors – August 2010
Based on Published Tariffs**

City (Service Territory)	Austin (AE) ¹		Brownsville (Brownsville Public Utilities Board) ²		New Braunfels (NBU) ³		San Marcos (City of San Marcos Utility Service)		San Antonio (CPS Energy) ⁴		Elgin (Bluebonnet EC) ⁵		Cedar Park (Pedernales EC) ⁶		Beaumont (Entergy Texas) ⁷	
Small Commercial - Total Monthly Bill (10 kW Demand)																
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
20% LF	153	127	161	161	132	117	134	134	148	142	170	170	169	169	179	179
60% LF	448	369	416	416	355	311	382	382	383	355	456	456	432	432	423	423
Small Commercial - Total Monthly Bill (35 kW Demand)⁸																
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
7,500 kWh	900	852	688	688	594	519	648	648	770	719	798	798	712	712	779	779
15,000 kWh	1,309	1,261	1,342	1,342	1,167	1,017	1,285	1,285	1,269	1,161	1,547	1,547	1,387	1,387	1,354	1,354
Medium Commercial - Total Monthly Bill (100 kW Demand)																
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
40% LF	2,995	2,857	1,760	1,760	2,253	1,961	2,574	2,574	2,688	2,473	2,903	2,903	2,756	2,756	2,747	2,747
80% LF	4,588	4,450	3,134	3,134	4,486	3,902	4,773	4,773	4,616	4,182	5,106	5,106	4,963	4,963	4,982	4,982
Medium Commercial - Total Monthly Bill (300 kW Demand)⁸																
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
87,000 kWh	8,027	7,730	4,989	4,989	7,356	6,486	7,587	7,587	7,984	7,336	8,413	8,413	7,924	7,924	8,113	8,113
174,000 kWh	12,424	12,127	9,083	9,083	12,948	11,208	14,139	14,139	13,727	12,427	14,977	14,977	14,497	14,497	13,965	13,965
Medium Commercial - Total Monthly Bill (500 kW Demand)⁸																
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
145,000 kWh	13,378	12,883	8,074	8,074	12,269	10,819	12,656	12,656	13,293	12,210	13,939	13,939	13,106	13,106	13,495	13,495
290,000 kWh	20,707	20,212	14,897	14,897	21,588	18,688	21,713	21,713	22,866	20,695	24,878	24,878	24,062	24,062	22,994	22,994
Large Commercial - Total Monthly Bill (2.5 MW Demand)⁸																
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
720,000 kWh	66,639	64,164	46,229	46,229	61,149	53,949	60,482	60,482	64,261	58,886	60,427	60,427	63,266	63,266	63,709	62,417
1,440,000 kWh	103,028	100,553	79,853	79,853	107,424	93,024	113,013	113,013	99,195	93,820	108,379	108,379	116,582	116,582	105,226	103,940
Small Industrial - Total Monthly Bill (5 MW Demand)																
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
40% LF	129,447	121,011	93,287	93,287	123,834	109,234	120,263	120,263	128,674	117,924	127,711	127,711	126,863	126,863	126,995	124,410

80% LF	196,193	185,023	161,469	161,469	217,668	188,468	225,326	225,326	200,097	189,347	218,947	218,947	235,976	235,976	212,367	209,796
Industrial - Total Monthly Bill (25 MW Demand)																
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
40% LF	637,891	596,065	466,015	466,015	611,671	538,671	598,515	598,515	639,367	585,617	606,655	606,655	457,430	457,430	633,283	620,356
80% LF	1,062,947	914,131	806,925	806,925	1,080,842	934,842	1,123,831	1,123,831	996,483	942,733	1,092,835	1,092,835	888,860	888,860	1,060,144	1,047,290

Source: Published tariffs rates

<http://www.austinenergy.com/About%20Us/Rates/Commercial/index.htm>

<http://www.bluebonnetelectric.coop/documents/RateScheduleforwebsite7.6.10.pdf>

https://www.pec.coop/Documents/PEC_Tariff_0618.pdf

http://www.cpsenergy.com/Commercial/Billing_Payments/Rates/index.asp

http://www.entergy-texas.com/your_business/business_tariffs.aspx

<http://www.brownsville-pub.com/commercial/elecrates.html>

<http://www.nbutexas.com/Portals/11/pdf/Electric%20Rates%203-09.pdf>

Table Notes:

Prices in **blue text** represent the minimum bill in cases where multiple services are available in a demand class. For example AE’s summer price for 10 kW service at a 60% load factor for a customer receiving “General Service Non-Demand” would have been \$448, while the General Service Demand price would have been \$379, as shown above.

- ¹ AE electricity bills were calculated as follows: 10 kW bills based on General Service Non-demand (EO2); 35 kW and 100 kW bills were calculated at General Service Demand (EO6) rates; 300 kW, 500 kW and 2.5 MW bills were calculated at Primary Service (EO7) rates; 5 MW bills were calculated based on Large Primary Service Special Contract Rider Time-Of-Use (LTC 2/3) and 25 MW bills were calculated based on Large Primary Service Special Contract Rider Time-Of-Use (LTC 2/3) and the Large Primary Service Special Contract - Industrial Rider Time-Of-Use (LTC 1). Fuel adjustment factor = \$0.03653/ kWh. Primary fuel adjustment factor = \$0.03544/kWh.
- ² BPUB electricity bills were calculated as follows: 10 kW and 35 kW based on General Service – Non-Demand rate; 100 kW and 300 kW based on General Service Demand rate; 500 kW based on both General Service Demand and General Service Large Demand rates; 2.5 MW and 25 MW based on General Service Large Demand rate. Fuel adjustment factor = \$0.0422/kWh.
- ³ NBU bills were calculated as follows: 10 kW, 35 kW, and 100 kW based on Small General Service rate; 300 kW, 500 kW 2.5 MW, 5 MW and 25 MW based on Large General Service rate. Fuel adjustment factor = \$0.014268.
- ⁴ CPS Energy electricity bills were calculated as follows: 10 kW, 35 kW, 100 kW, 300 kW, 500 kW based on General Service (PL) rate; 2.5 MW, 5 MW and 25 MW based on Extra Large Power Service (ELP) rate assuming primary service. Fuel adjustment factor = \$0.016024/ kWh.
- ⁵ BEC electricity bills were calculated as follows: 10 kW and 35 kW based on Three-phase Commercial Service rate; 100 kW based on Large Power rate; 300 kW, 500 kW, 2.5 MW, 5 MW and 25 MW based on Key Account rate with “wholesale power cost” equal to \$0.072674/ kWh.
- ⁶ PEC electricity bills were calculated as follows: 10 kW and 35 kW based on the Small Power rate; 100 kW, 300 kW, 500 kW, 2.5 MW and 5 MW based on Large Power secondary level service rate; 25 MW based on Industrial Power rate. Fuel adjustment factor = (\$0.007)/ kWh.
- ⁷ Entergy Texas electricity bills were calculated as follows: 10 kW based on Small General Service and General Service rate; 35 kW and 100 kW based on General Service rate; 300 kW and 500 kW based on both General Service and Large General Service rates; and 2.5 MW and 5 MW based on both Large General Service and Large Industrial Power Service rates; and 25 MW based on Large Industrial Power Service rate. Fuel adjustment factor = \$0.0547115 / kWh.
- ⁸ Pricing at four demand levels (35 kW, 300 kW, 500 kW, and 2.5 MW) was calculated at the following kWh’s rather than at specific load factors to match data provided to the PUCT: 35 kW at 7,500 kWh and 15,000 kWh; 300 kW at 87,000 kWh and 174,000 kWh; 500 kW at 145,000 kWh and 290,000 kWh; 2.5 MW at 720,000 kWh and 1,440,000 kWh.

Conclusions

Data Assumptions and Limitations

R. W. Beck's mission for this study was to compare AE customer electricity bills with customer electricity bills in selected cities across the state. Major challenges exist in comparing electricity bills in different regions. In the competitive areas of Texas, energy service is provided by competitive firms via private contracts between the supplier and the customer. The terms of these contracts are typically confidential. For this reason, it is extremely difficult to collect actual bills and contract provisions for the competitive areas of the State. There is no available collected data set or survey that can be used to compare electricity bills. Since each individual customer may be served under unique terms, knowing the terms and prices of a few customers may not be representative of actual energy prices in the broader market. Therefore, R. W. Beck used several different approaches to estimate representative electricity bills across the state.

In the regulated portions of the state—those served by municipal utilities like AE, by cooperative utilities, and the non-ERCOT portions of the State—utility rates are based on tariffs adopted by regulating authorities, for example city councils. These tariffs include all the costs of providing electric service. However, many factors come into play for these utilities in setting rates and tariffs. These factors include the service territory location within ERCOT, the type and characteristics of the mix of customers in the territory, the strategic aspirations of the utility owners, power supply characteristics including fuel mix and age of assets, and others. The reader should also recognize this comparison is a snapshot of a point in time or period of time and some utilities are in the process of changing tariffs which could change their comparative position within this group. For example, Centerpoint is currently before the PUC for a tariff change⁹.

It was also necessary to establish early in the study what customer classifications were to be used for bill comparisons. R. W. Beck has chosen to classify customers using 16 load/size factor combinations. This classification protocol was developed by AE and R. W. Beck to provide a diverse and representative sample of AE's different customer types. The variety of customer load sizes range from as small as a 10 kW commercial load to an extremely large 25 MW customer. Prices for two different load factors for each load level were also estimated. These different load factors are important because the load factor differentiates one dimension in the costs of providing service to a customer—whether the customer has predictable, steady load level, or whether the customer has a highly variable load level and is therefore more expensive to serve. Though we report comparative results for each of these 16 combinations of load and load factor, R. W. Beck cannot emphasize enough that the particular characteristics of each customer will dictate what type of service contract is appropriate for a customer.

R. W. Beck also calculated monthly representative electricity bills for AE's commercial and industrial customer bills. The R. W. Beck team used AE rates schedules specified by AE to

⁹ See PUCT Docket No. 38339

calculate the representative monthly bills at numerous demand and load factors and our calculations validate AE's prices reported to the PUCT.

Comparison Methodologies Used

Two methods were used to estimate electricity bills in competitive areas of the state;

1. Heat Rate Method
2. Market Clearing Price of Energy ("MCPE") Method

AE's calculated electricity bills based on published tariffs were compared with results from electricity bills estimated using both methods.

Heat Rate factors were estimated for the 16 customer size and usage levels using the R. W. Beck team's historic knowledge of market pricing for customers in the various competitive zonal sub-markets in ERCOT. For this analysis the range of heat rate factors used varied between a low of 9.4 to a high of 12.0. It is important to remember that these heat rate factors are for retail energy delivered to the distribution utility and include all potential energy charges including ancillary services, losses, ERCOT fees, load following costs, and all REP charges. The assumed heat rate was multiplied by the average natural gas futures prices for 2009 delivery to determine a cost of energy. When appropriate, zonal energy price differentials were also accounted for using annual average historic differences in MCPE zonal energy prices. Once the energy rates were estimated, TDSP charges were calculated for the assumed demand and energy usage of the customer and these costs were added to the calculated energy charges to achieve an estimated total bill.

For the MCPE method, R. W. Beck used historic MCPE data obtained from ERCOT to compute average daily on-peak and off-peak prices. Average daily pricing was then used to calculate average monthly energy pricing. Sometimes an additional adder is applied by the retail electricity provider to the market price. In this analysis we included a \$0.012 per kWh adder to the reported market price. Once the energy rates were estimated, TDSP charges at the assumed demand and load factor were added to the calculated energy charges to achieve an estimated total monthly bill. Finally, a yearly average bill was calculated at both on-peak and off-peak pricing levels.

In regulated areas, one comparison method was used. AE's calculated electricity bills based on published tariffs were compared across the 16 demand and load factor levels with electricity bills calculated for seven electric utility providers in non-competitive areas of Texas. Published tariff rates for these utilities were used to calculate a representative bill for each of the 16 demand and load factor levels. This bill calculation included fixed charges such as a monthly service fee and all applicable variable costs, based on data availability.

R. W. Beck also presented comparisons between AE tariff-calculated electricity bills with information published by the Electric Division of the PUCT. This information provides a commercial monthly electric bill comparison based on data collected from various utilities in markets within Texas that are not yet open to competition. The data are limited to utilities who participate in the survey and computations are provided by each participating utility; hence this analysis was limited to available data. Each utility calculates a typical customer's bill for a total of eight demand/load factor usage levels based on their internal rate tariff.

This study also presents DOE-EIA based data. This DOE-EIA cannot be used to estimate electricity bills for specific customer classifications of load and load factor. This data is self-reported by utilities at an aggregated level, so only provider-by-provider averages can be used, and even those comparisons should be conducted carefully.

AE Comparative Results

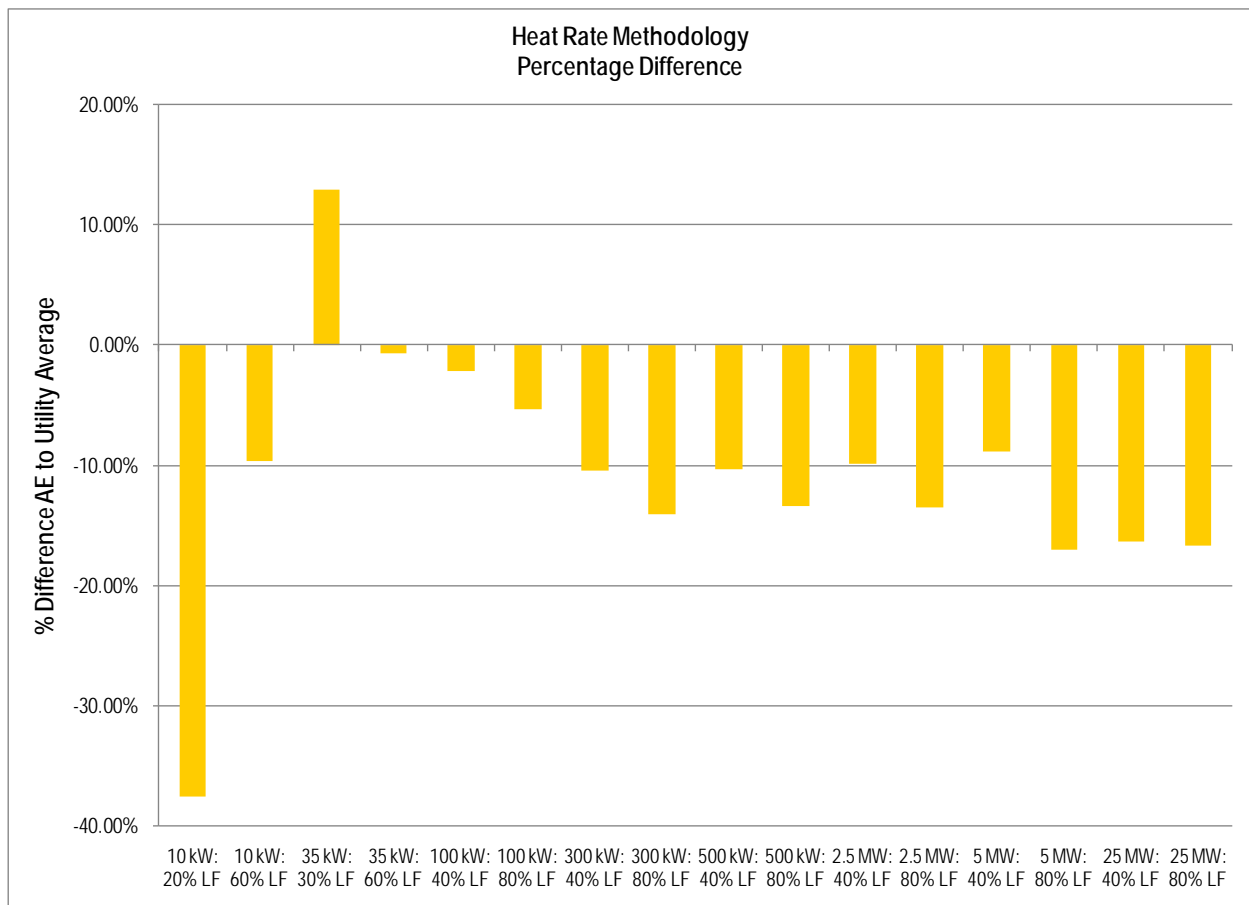
Table 9 provides an overview of AE estimated electricity bills compared to the average of electricity bills estimated for other city/metropolitan areas included in our analysis using the Heat Rate and Published Tariffs Methodologies. Table 9 does not include MCPE results because this method exhibits considerable volatility in price and higher levels of risk for the customer. Therefore, the MCPE method does not compare well with AE's approach to pricing electricity. The information provided in the report related to DOE-EIA rate comparisons and the PUCT bill comparison survey was not included because the data provided by the utilities is self-reported and cannot be validated.

Table 9						
AE Bills and Utility Monthly Electricity Bill Averages Summary Comparison						
	Heat Rate Methodology – 2009			Published Tariffs Methodology – Through July 2010		
	Austin Energy (per Tariff)	Utility Average	Percentage Difference	Austin Energy Summer	Utility Average	Percentage Difference
10 kW						
20% Load Factor	\$140	\$193	-37.50%	\$153	\$156	-2.05%
60% Load Factor	409	449	-9.66	448	407	9.22
35 kW*						
7,500 kWh	876	763	12.93	900	713	20.81
15,000 kWh	1,285	1294	-0.68	1,309	1,357	-2.05
100 kW						
40% Load Factor	2,926	2,990	-2.17	2,995	2,526	15.66
80% Load Factor	4,519	4,760	-5.33	4,588	4,580	0.17
300 kW*						
87,000 kWh	7,878	8,669	-10.42	8,027	7,481	6.80
174,000 kWh	12,275	14,007	-14.11	12,424	13,334	-7.32
500 kW*						
145,000 kWh	13,131	14,494	-10.38	13,378	12,405	7.28
290,000 kWh	20,459	23,208	-13.44	20,707	21,857	-5.55
2.50 MW*						
720,000 kWh	65,401	71,837	-9.84	66,639	59,932	10.06
1,440,000 kWh	101,790	115,485	-13.45	103,028	104,239	-1.18
5 MW						
40% Load Factor	125,229	136,242	-8.79	129,447	121,090	6.46
80% Load Factor	190,608	223,154	-17.07	196,193	210,264	-7.17
25 MW						
40% Load Factor	616,978	717,954	-16.33	637,891	573,277	10.13
80% Load Factor	988,539	1,153,502	-16.69	1,062,947	1,007,131	5.25

*Pricing at four demand levels (35 kW, 300 kW, 500 kW, and 2.5 MW) was calculated at the following kWh's rather than at specific load factors to match data provided to the PUCT: 35 kW at 7,500 kWh and 15,000 kWh; 300 kW at 87,000 kWh and 174,000 kWh; 500 kW at 145,000 kWh and 290,000 kWh; 2.5 MW at 720,000 kWh and 1,440,000 kWh.

As illustrated in Figure 7, AE's estimated electricity bills compared to bills estimated using the Heat Rate Methodology tend to be lower than the estimated average electricity bills for other city/metropolitan areas at different size and load factors. The only exception where AE is higher than then utility average is at 35kW with a 30 percent load factor.

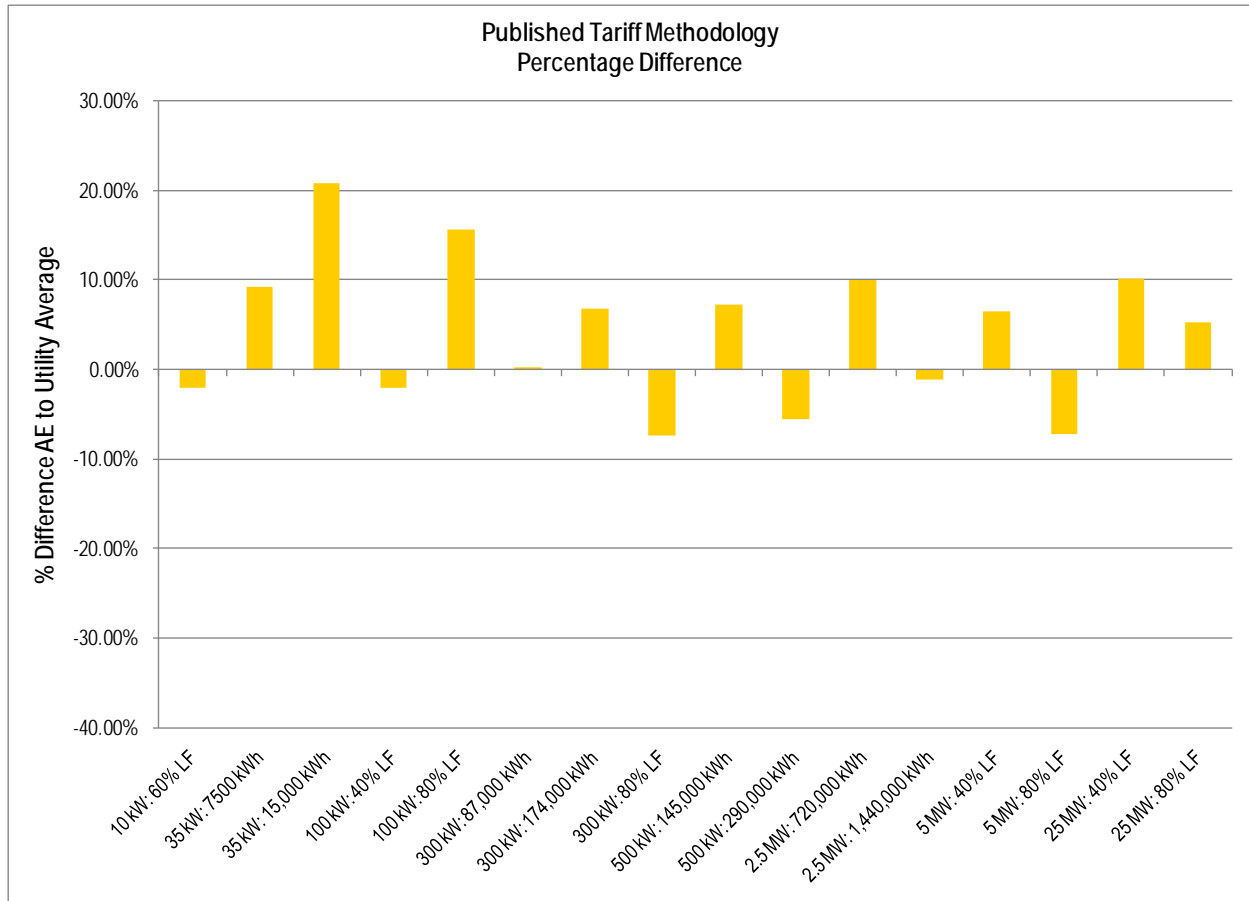
**Figure 7:
AE Bills and Utility Monthly Electricity Bill Averages Summary Comparison
Heat Rate Bill Methodology – 2009**



Source: Table 3 of this Report

AE's estimated electricity bills compared to bills estimated using published tariff information tend to be higher at certain size and load factors. AE's estimated bills are lower at 10 kW - 20 percent load factor, 35 kW – 15,000 kWh, 300 kW- 174,000 kWh, 500 kW – 290,000 kWh, 2.5 MW – 1,440,000 kWh, and 5 MW at an 80 percent load factor, as illustrated in Figure 8.

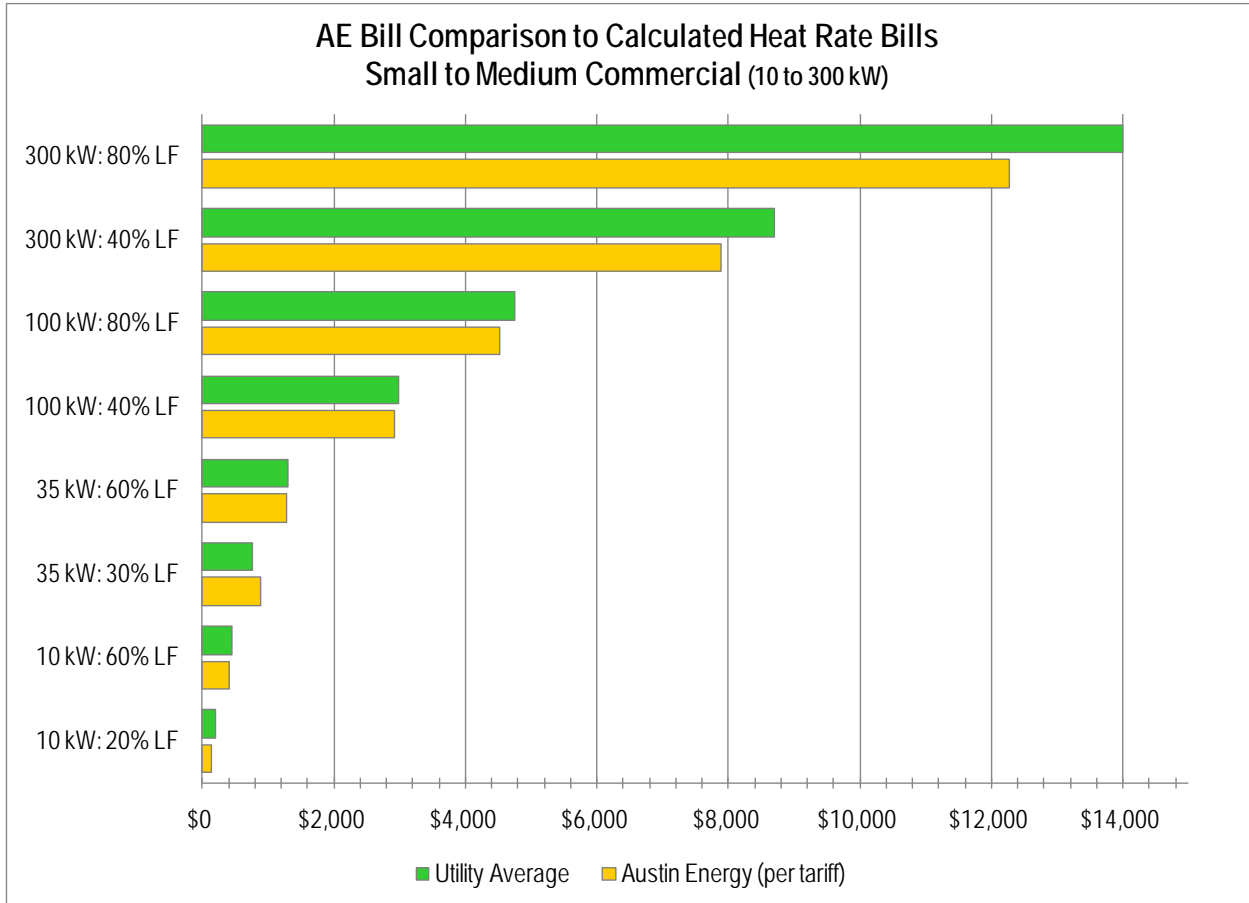
**Figure 8:
AE Bills and Utility Monthly Electricity Bill Averages Summary Comparison
Published Tariff Methodology – Through July 2010**



Source: Table 8 of this Report

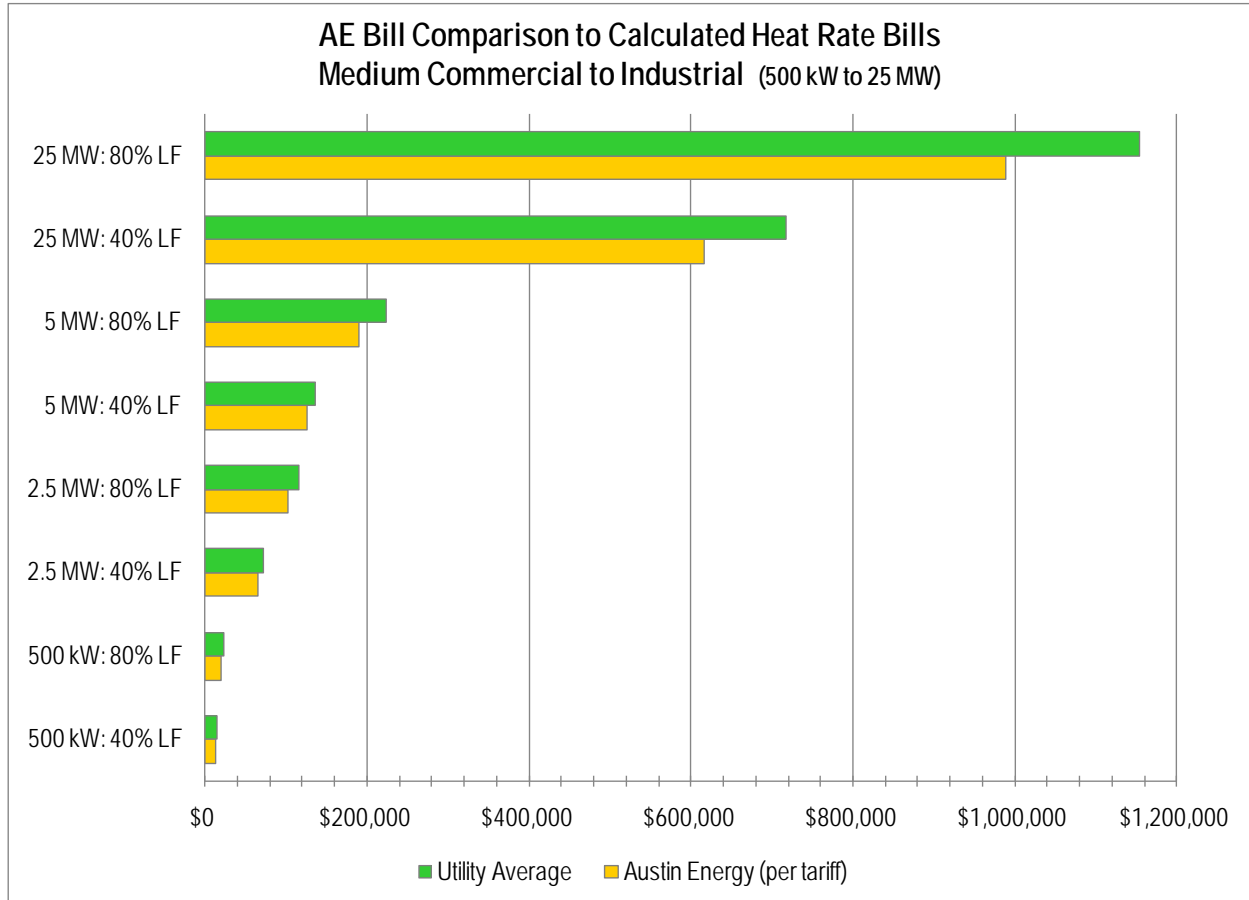
Figures 9 and 10 show that AE electricity bills calculated from published tariffs compare favorably with the simple average of representative electricity bills for utilities in competitive areas of the state calculated using the Heat Rate method. The estimates indicate that AE’s electricity bills are most competitive for the larger customers. AE’s electricity bills also appear to be more competitive for customers with higher load factors than the comparably sized customers at lower load factors. This could be the result of a policy or organizational objective to create incentives that reward customers with higher load factors. The Heat Rate method compares electricity bills in AE’s territory for each of the 16 load level classifications with the average estimated bill for 2009 in the four TDSP markets in Texas.

**Figure 9:
Heat Rate Bill Comparison - Small to Medium Commercial - 2009**



Source: Table 3 of this Report

**Figure 10:
Heat Rate Bill Comparison - Medium Commercial to Industrial - 2009**

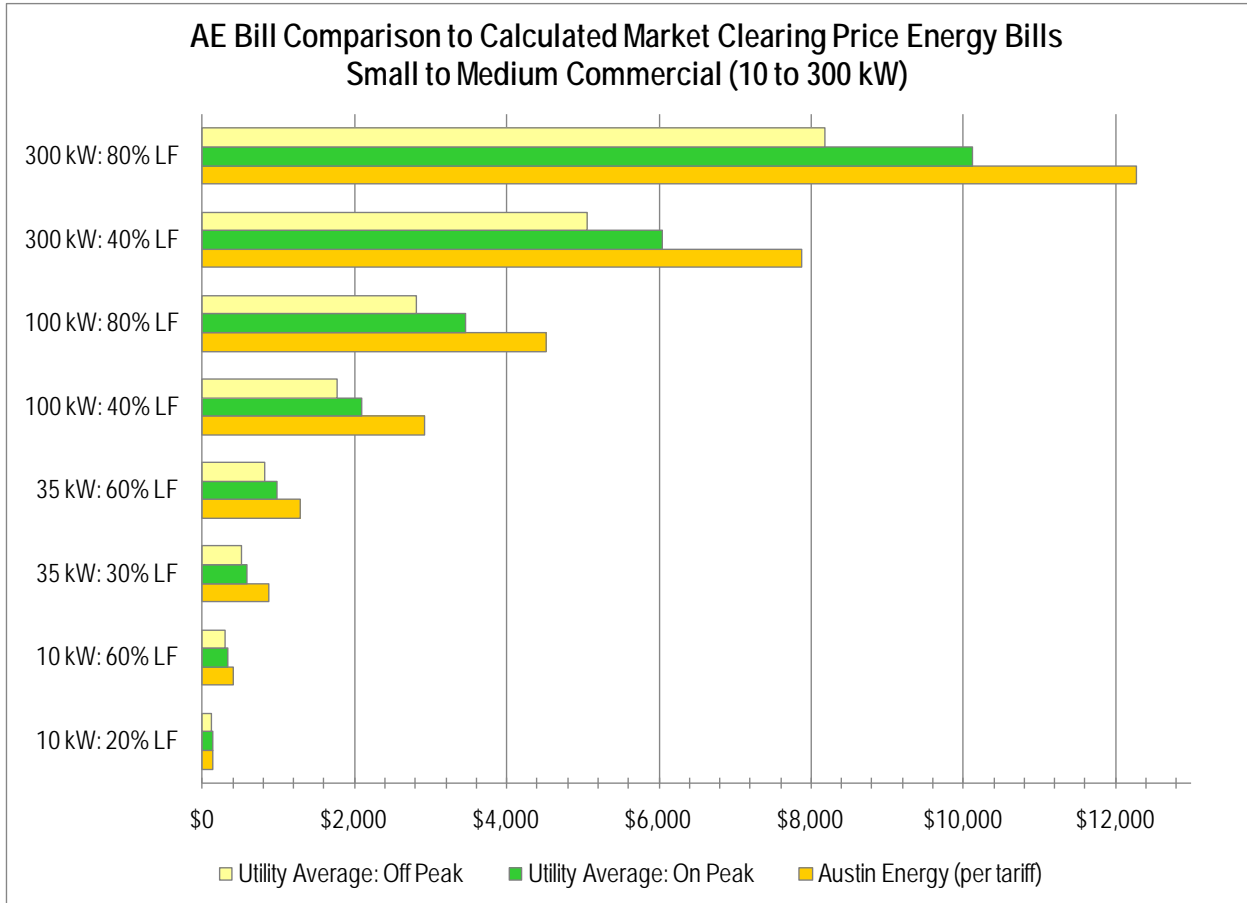


Source: Table 3 of this Report

As expected, electricity bills calculated using published tariffs from a selected group of electric cooperatives and municipal utilities exhibit considerable variability. Many factors come into consideration for these utilities in setting rates and tariffs. Factors include the service territory location within ERCOT, the strategic aspirations of the utility owners, power supply characteristics including fuel mix and age of assets, among others. The reader should also recognize that this comparison is a snapshot of one point in time or period of time and some utilities are in the process of changing tariffs which could ultimately change their comparative position within this group.

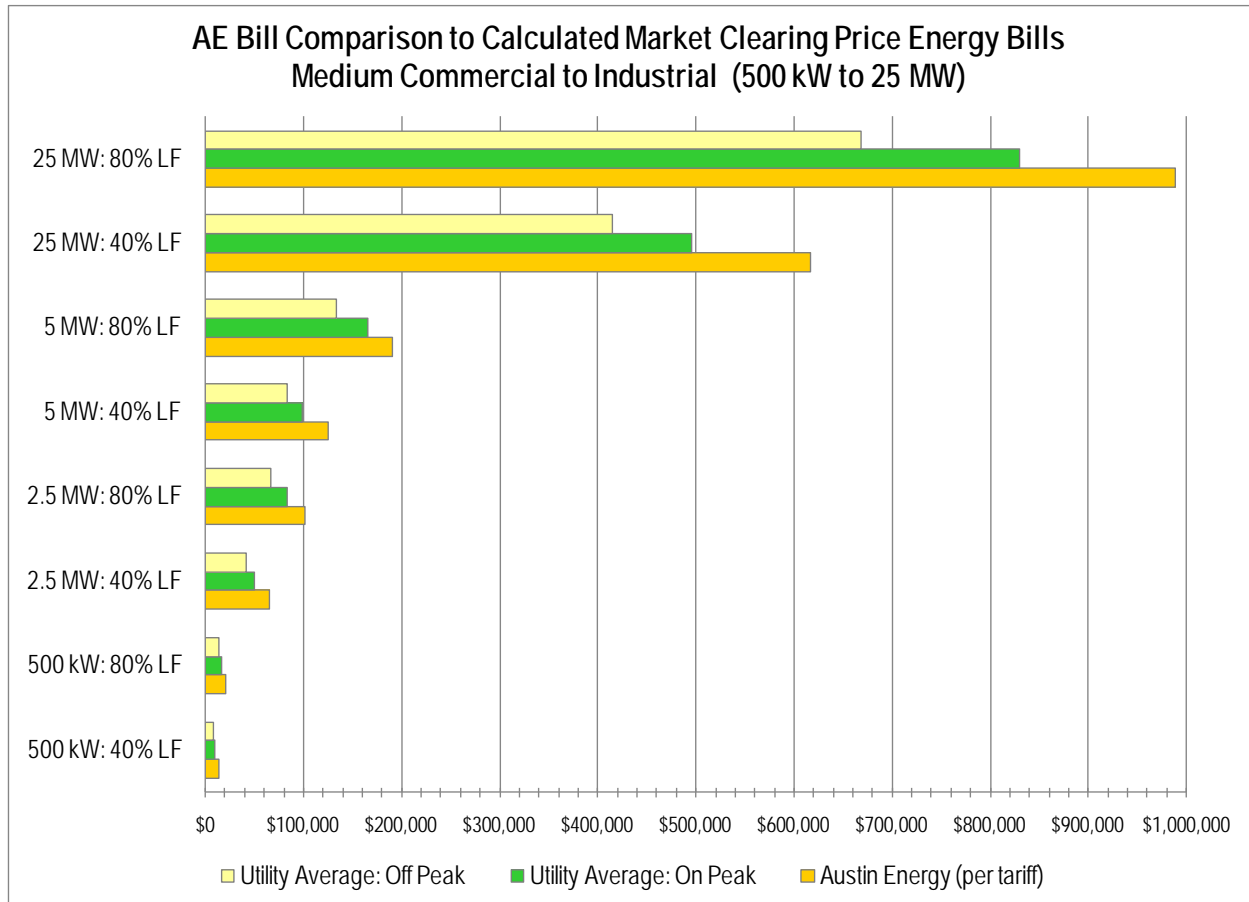
The MCPE method compares the calculated average monthly price at selected demand levels and load factors based on actual market clearing prices for 2009, which are illustrated in Figures 11 and 12.

**Figure 11:
MCPE Bill Comparison – Small to Medium Commercial - 2009**



Source: Table 5 of this Report

**Figure 12:
MCPE Bill Comparison - Medium Commercial to Industrial - 2009**



Source: Table 5 of this Report

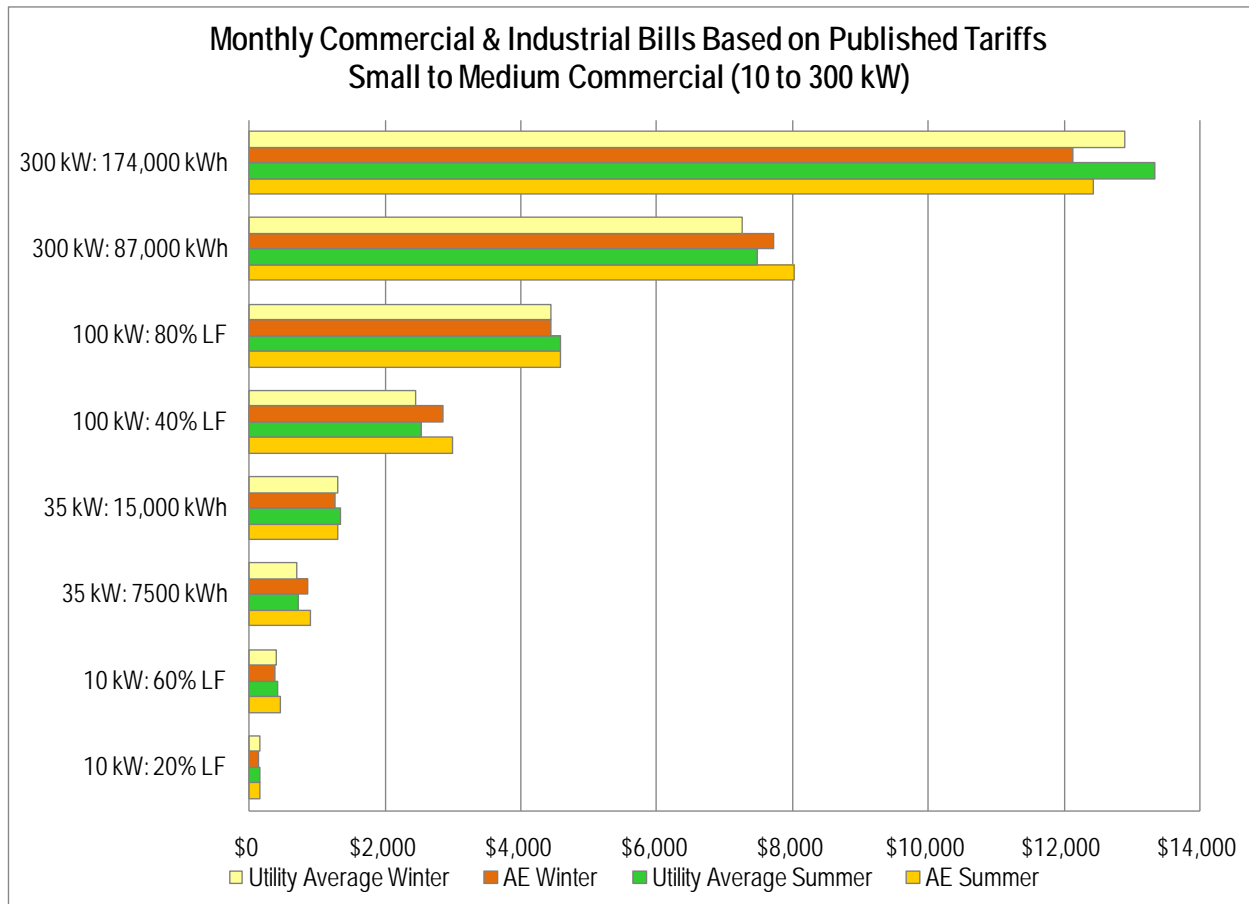
Figures 11 and 12 show that AE electricity bills calculated from published tariffs are generally higher than the average of representative electricity bills for utilities in competitive areas of the state calculated using the MCPE method. This is to be expected. The MCPE method produces a lower calculated electricity bill than the average of representative electricity bills for utilities in competitive areas of the state calculated using the Heat Rate method. Indeed, with few exceptions the MCPE method will also produce a lower electricity bill than representative electricity bills for utilities in regulated areas based on published tariffs. AE tariffs, like Heat Rate-type electricity supply contracts, are fixed price and exhibit a much lower volatility and energy price risk than MCPE-type contracts. The MCPE method introduces considerable volatility in price and higher levels of risk for the customer.

As expected, electricity bills calculated using published tariffs from a selected group of electric cooperatives and municipal utilities exhibit considerable variability. Many factors come into consideration for these utilities in setting rates and tariffs. Factors include the service territory location within ERCOT, the strategic aspirations of the utility owners, power supply characteristics including fuel mix and age of assets, among others. The reader should also

recognize that this comparison is a snapshot of one point in time or period of time and some utilities are in the process of changing tariffs which could ultimately change their comparative position within this group.

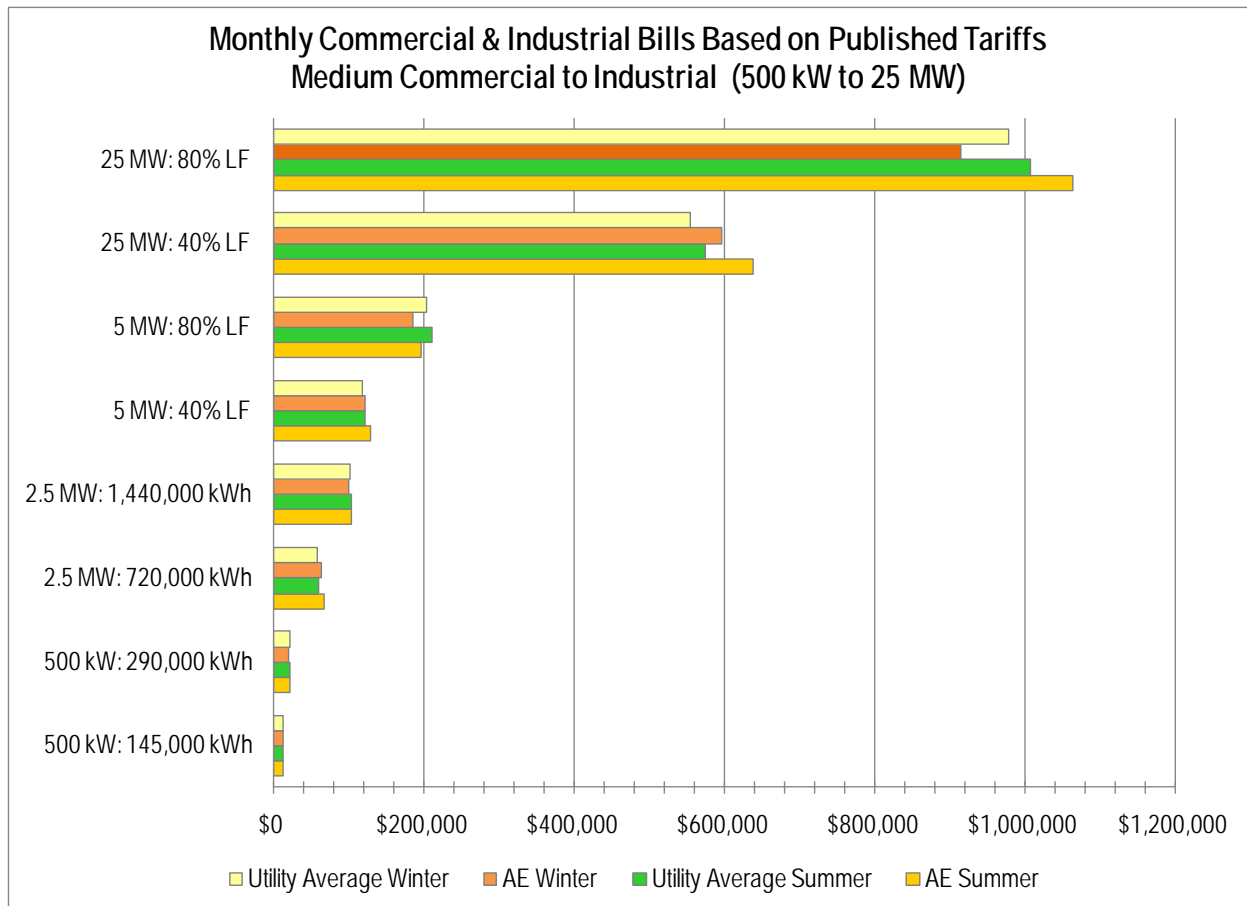
The published tariffs electricity bill comparison compares calculated AE electricity bills to other electricity bills using published public utility tariff information through July 2010, as illustrated in Figures 13 and 14.

**Figure 13:
Published Tariffs Bill Comparison – Small to Medium Commercial – Through July 2010**



Source: Table 8 of this Report

**Figure 14:
Published Tariffs Bill Comparison –Medium Commercial to Industrial –
Through July 2010**



Source: Table 8 of this Report

The analysis contained within this study demonstrates that electricity bills calculated using AE’s published tariffs compare favorably with electricity bills estimated or calculated for other competitive and regulated areas of the state. This statement applies to pricing arrangements that are similar to AE’s electricity pricing terms. That is, pricing arrangements that can be categorized as “low risk, fixed term.” Lower pricing arrangements are available in the Texas market, but such arrangements will be higher risk, variable-term arrangements. As such, those arrangements are not similar to AE’s tariff-based pricing.

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Glossary¹⁰

Bilateral Contracts: In a bilateral market, contracts between power generating companies and load serving entities.

Commercial Customer: Include businesses such as retail stores, restaurants and educational institutions with a peak demand of 50 kW or more during any twelve month period. Small commercial customers may include businesses whose peak electric demand during any twelve month period is less than 50 kW.

Congestion: The situation that exists when requests for power transfers across a Transmission Facility element or set of elements, when netted, exceed the transfer capability of such elements.

Congestion Zone: An area of the transmission network that is bound by commercially significant transmission constraints or otherwise identified as a zone that is subject to transmission constraints, as defined by an independent organization.

Day Ahead: The 24-hour period before the start of the Operating Day.

Demand: The rate at which electric energy is delivered to or by a system at a given instant, or averaged over a designated period, usually expressed in kilowatt (“kW”) or megawatt (“MW”).

Department of Energy (“DOE”): A US federal agency established in 1977 which brings all major energy-related federal agencies under a single umbrella.

Electric Cooperative: (a) a corporation organized under the Texas Utilities Code, Chapter 161 or a predecessor statute to Chapter 161 and operating under that Chapter; (b) a corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate or authority to conduct affairs in the State of Texas; or (c) a successor to an electric cooperative created before June 1, 1999, in accordance with a conversion plan approved by a vote of the members of the electric cooperative, regardless of whether the successor later purchases, acquires, merges with or consolidates with other electric cooperatives.

Electric Reliability Council of Texas (“ERCOT”): Refers to the independent organization and, in a geographic sense, refers to the area served by electric utilities, municipally-owned utilities, and electric cooperatives that are not synchronously interconnected with electric utilities outside the state of Texas.

¹⁰ Chapter 25. Substantive Rules Applicable to Electric Service Providers. Subchapter A. General Provisions. §25.5 Definitions. www.puc.state.tx.us

ERCOT online glossary: www.ercot.com/glossary

Window of State Government, online Energy Glossary: www.window.state.tx.us/specialrpt/energy/glossary

Energy Vortex Online Dictionary: www.energyvortex.com/energydictionary

Electric Utility: A person or river authority that owns or operates for compensation in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in this state.

Energy Information and Administration (“EIA”): A US federal agency whose primary responsibility is management of statistics relating to energy production, use and consequences.

Generation: Assets, activities and processes necessary and related to the production of electricity.

Grid: A system of interconnected generating facilities, transmission corridors and power lines that provide energy to a group of customers.

Heat Rate: A measurement used in the energy industry to calculate how efficiently a generator uses heat energy.

Industrial Customer: Include factories or manufacturing plants and typically have the highest demand for electricity.

Kilowatt (“kW”): A measure of electrical power equal to 1,000 watts.

Kilowatt hour (“kWh”): A quantitative measure of electric current flow equivalent to one thousand watts being used continuously for a period on one hour; the unit most commonly used to measure electrical energy, as opposed to kilowatt, which is simply a measure of available power.

Line Losses: Difference between energy input into the Transmission Grid and the energy taken out of the Transmission Grid.

Load: a) the amount of energy used per hour or kilowatt-hour or, b) the level of electricity demanded or kilowatt.

Load Factor: A measure of the average load, in kilowatts, supplied during a given period. It is used to determine the total amount of energy that would have been used if a given customer's maximum load was sustained over an extended period of time. This value offers a useful comparison to show what percentage of a customer's potential usage is actually used.

Load Serving Entities (“LSEs”): An Entity that sells energy to Customers or Wholesale Customers and that has registered as an LSE with ERCOT. LSEs include Competitive Retailers (which includes REPs) and NOIEs that serve Load.

Load Size: a) the amount of energy used per hour or kilowatt-hour (“kWh”); or, b) the level of electricity demanded or kilowatt (“kW”).

Market Clearing Price for Energy: The highest price associated with a Congestion Zone for a Settlement Interval for Balancing Energy deployed during the Settlement Interval.

Municipally-owned Utility: Any utility owned, operated, and controlled by a municipality or by a nonprofit corporation whose directors are appointed by one or more municipalities.

Megawatt (“MW”): The electrical unit of power that equals 1 million Watts (1,000 kW).

Nodal Market: In the nodal market design, the electric grid will consist of more than 4,000 nodes, replacing the Congestion Management Zones that exist under the Zonal Market. The Texas nodal market is expected to deliver benefits such as improved price signals, improved dispatch efficiencies, and direct assignment of local congestion.

Not-Opt In Entity (“NOIE”): An electric cooperative or municipally-owned utility that does not offer customer choice.

Off-Peak Hours: All hours that are not on-peak, which end in 0700 to 2200 CPT from Monday through Friday excluding NERC holidays.

On-Peak: Hours ending in 0700 to 2200 CPT from Monday through Friday excluding NERC holidays.

Peak Load or Peak Demand: Highest need of the system.

Public Utility Commission of Texas (“PUC”): Formed in 1975 by the Legislature as a rate regulatory body, PUC now, since deregulation, oversees electric and telecommunications companies to ensure Texas consumers have access to competitive utility services. The PUC oversees competition in the wholesale and retail electricity and telecommunications markets, and regulates rates and services of non-competitive electric utilities and local exchange companies.

Qualifying Scheduling Entity (“QSE”): A market participant that is qualified by ERCOT to submit balanced schedules and ancillary services bids and settle payments with ERCOT.

Rate: A compensation, tariff, charge, fare, toll, rental or classification that is directly or indirectly demanded, charged or collected by an electric utility for a service, product, or commodity.

Residential Customer: Include private households that utilize energy for such needs as heating, cooling, cooking, lighting and small appliances.

Retail Electric Provider (“REP”): A person that sells electric energy to retail customers in this state.

Tariff: The schedule of a utility, municipally-owned utility or electric cooperative containing all rates and charges stated separately by type of service, the rules and regulations of the utility, and any contracts that affect rates, charges terms or conditions of service.

Transmission and/or Distribution Service Provider (“TDSP”): An Entity that is a TSP, a DSP or both, or an Entity that has been selected to own and operate Transmission Facilities and has a PUCT approved code of conduct.

Transmission Service: Service that allows a transmission service customer to use the transmission and distribution facilities of electric utilities, electric cooperatives and the municipally owned utilities to efficiently and economically utilize generation resources to reliably serve its load and to deliver power to another transmission service customers.

Zonal Market: In the zonal market, the electric grid is divided into Congestion Management Zones, which are defined by Commercially Significant Constraints. Several limitations have been identified with the zonal market such as: insufficient price transparency, resources are grouped by portfolio, and the indirect assignment of local congestion.

EXHIBIT 1

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Exhibit 1
Range of Hourly MCPE Prices Used for MCPE Price Calculations
Source: ERCOT

Average Monthly Price used for analysis, based on hourly data for 2009 and 2010																
Date	Month	Day	Hour Ending	Price				On Peak Price				OFF PeakPrice				
				NORTH	SOUTH	WEST	HOUSTON	NORTH	SOUTH	WEST	HOUSTON	NORTH	SOUTH	WEST	HOUSTON	
				Oncor-Dallas	AEP Central	AEP North	Center Point - HOUSTON	Oncor-Dallas	AEP Central	AEP North	Center Point - HOUSTON	Oncor-Dallas	AEP Central	AEP North	Center Point - HOUSTON	
	Jan		2009	\$ 30.78	\$ 32.31	\$ 23.23	\$ 31.54	\$ 32.28	\$ 35.10	\$ 27.78	\$ 33.76	\$ 27.79	\$ 26.72	\$ 14.12	\$ 27.09	
	Feb		2009	\$ 26.86	\$ 26.28	\$ 19.66	\$ 26.48	\$ 29.22	\$ 28.57	\$ 21.06	\$ 28.79	\$ 22.14	\$ 21.72	\$ 16.87	\$ 21.86	
	Mar		2009	\$ 29.82	\$ 25.58	\$ 24.01	\$ 28.25	\$ 33.42	\$ 25.27	\$ 28.54	\$ 28.73	\$ 22.62	\$ 26.20	\$ 14.96	\$ 27.27	
	Apr		2009	\$ 24.10	\$ 23.45	\$ 12.91	\$ 23.90	\$ 25.71	\$ 25.10	\$ 15.17	\$ 25.53	\$ 20.88	\$ 20.14	\$ 8.39	\$ 20.63	
	May		2009	\$ 30.61	\$ 30.58	\$ 23.45	\$ 30.63	\$ 32.29	\$ 32.52	\$ 27.23	\$ 32.47	\$ 27.24	\$ 26.71	\$ 15.91	\$ 26.93	
	Jun		2009	\$ 31.69	\$ 66.89	\$ 30.57	\$ 51.28	\$ 36.02	\$ 88.41	\$ 35.46	\$ 65.18	\$ 23.03	\$ 23.86	\$ 20.80	\$ 23.48	
	Jul		2009	\$ 32.92	\$ 32.99	\$ 31.90	\$ 33.07	\$ 37.79	\$ 37.93	\$ 37.51	\$ 38.00	\$ 23.19	\$ 23.09	\$ 20.67	\$ 23.23	
	Aug		2009	\$ 29.90	\$ 30.16	\$ 28.07	\$ 30.44	\$ 34.05	\$ 34.01	\$ 33.24	\$ 34.05	\$ 21.61	\$ 22.46	\$ 17.75	\$ 23.23	
	Sep		2009	\$ 25.11	\$ 28.32	\$ 23.28	\$ 28.66	\$ 28.49	\$ 31.37	\$ 26.84	\$ 32.68	\$ 18.34	\$ 22.21	\$ 16.14	\$ 20.61	
	Oct		2009	\$ 28.74	\$ 29.24	\$ 27.06	\$ 29.55	\$ 32.53	\$ 33.32	\$ 30.71	\$ 33.74	\$ 21.17	\$ 21.08	\$ 19.78	\$ 21.16	
	Nov		2009	\$ 26.59	\$ 26.68	\$ 26.58	\$ 26.65	\$ 29.85	\$ 29.98	\$ 29.86	\$ 29.94	\$ 20.08	\$ 20.08	\$ 20.02	\$ 20.08	
	Dec		2009	\$ 39.54	\$ 38.97	\$ 37.69	\$ 39.20	\$ 41.90	\$ 41.29	\$ 39.69	\$ 41.53	\$ 34.80	\$ 34.32	\$ 33.68	\$ 34.54	
	Jan		2010	\$ 40.82	\$ 41.47	\$ 37.86	\$ 41.24	\$ 43.25	\$ 44.28	\$ 40.95	\$ 43.84	\$ 35.97	\$ 35.84	\$ 31.67	\$ 36.03	
	Feb		2010	\$ 45.19	\$ 44.93	\$ 39.05	\$ 45.06	\$ 48.21	\$ 47.97	\$ 41.85	\$ 48.09	\$ 39.17	\$ 38.84	\$ 33.45	\$ 39.01	
	Mar		2010	\$ 32.18	\$ 31.72	\$ 22.08	\$ 31.96	\$ 34.82	\$ 34.41	\$ 26.71	\$ 34.62	\$ 26.92	\$ 26.33	\$ 12.82	\$ 26.64	
	Apr		2010	\$ 31.96	\$ 31.56	\$ 24.11	\$ 31.77	\$ 34.95	\$ 34.60	\$ 28.15	\$ 34.79	\$ 25.97	\$ 25.46	\$ 16.04	\$ 25.74	
	May		2010	\$ 32.80	\$ 32.92	\$ 29.13	\$ 33.15	\$ 37.38	\$ 37.48	\$ 33.78	\$ 37.69	\$ 23.62	\$ 23.81	\$ 19.85	\$ 24.06	

Exhibit 1
Range of Hourly MCPE Prices Used for MCPE Price Calculations
Source: ERCOT

Example showing hourly prices for first two days of January, 2009					Price				On Peak Price				OFF PeakPrice				
Date	Month	Day	Hour Ending		NORTH	SOUTH	WEST	HOUSTON	NORTH	SOUTH	WEST	HOUSTON	NORTH	SOUTH	WEST	HOUSTON	
					Oncor-Dallas	AEP Central	AEP North	Center Point - HOUSTON	Oncor-Dallas	AEP Central	AEP North	Center Point - HOUSTON	Oncor-Dallas	AEP Central	AEP North	Center Point - HOUSTON	
1/1/2009	1	1	1	\$	32.72	31.66	19.76	32.02					\$	32.72	31.66	19.76	32.02
1/1/2009	1	1	2	\$	51.31	44.50	(32.15)	46.83					\$	51.31	44.50	(32.15)	46.83
1/1/2009	1	1	3	\$	36.99	31.21	(33.92)	33.19					\$	36.99	31.21	(33.92)	33.19
1/1/2009	1	1	4	\$	27.28	22.25	(34.30)	23.97					\$	27.28	22.25	(34.30)	23.97
1/1/2009	1	1	5	\$	25.63	20.89	(32.47)	22.51					\$	25.63	20.89	(32.47)	22.51
1/1/2009	1	1	6	\$	32.76	27.35	(33.57)	29.21					\$	32.76	27.35	(33.57)	29.21
1/1/2009	1	1	7	\$	27.84	22.82	(33.72)	24.54	\$	27.84	22.82	(33.72)	24.54				
1/1/2009	1	1	8	\$	26.83	22.16	(30.43)	23.76	\$	26.83	22.16	(30.43)	23.76				
1/1/2009	1	1	9	\$	23.62	19.44	(27.64)	20.87	\$	23.62	19.44	(27.64)	20.87				
1/1/2009	1	1	10	\$	27.17	23.03	(23.51)	24.45	\$	27.17	23.03	(23.51)	24.45				
1/1/2009	1	1	11	\$	30.57	30.33	27.72	30.41	\$	30.57	30.33	27.72	30.41				
1/1/2009	1	1	12	\$	32.96	32.96	32.96	32.96	\$	32.96	32.96	32.96	32.96				
1/1/2009	1	1	13	\$	24.69	24.69	24.69	24.69	\$	24.69	24.69	24.69	24.69				
1/1/2009	1	1	14	\$	17.84	17.84	17.84	17.84	\$	17.84	17.84	17.84	17.84				
1/1/2009	1	1	15	\$	15.00	15.00	15.00	15.00	\$	15.00	15.00	15.00	15.00				
1/1/2009	1	1	16	\$	12.74	12.74	12.74	12.74	\$	12.74	12.74	12.74	12.74				
1/1/2009	1	1	17	\$	12.96	12.96	12.96	12.96	\$	12.96	12.96	12.96	12.96				
1/1/2009	1	1	18	\$	29.33	29.33	29.33	29.33	\$	29.33	29.33	29.33	29.33				
1/1/2009	1	1	19	\$	43.18	43.18	43.18	43.18	\$	43.18	43.18	43.18	43.18				
1/1/2009	1	1	20	\$	33.69	33.69	33.69	33.69	\$	33.69	33.69	33.69	33.69				
1/1/2009	1	1	21	\$	27.20	27.20	27.20	27.20	\$	27.20	27.20	27.20	27.20				
1/1/2009	1	1	22	\$	22.71	22.71	22.71	22.71	\$	22.71	22.71	22.71	22.71				
1/1/2009	1	1	23	\$	21.25	21.25	21.25	21.25					\$	21.25	21.25	21.25	21.25
1/1/2009	1	1	24	\$	16.48	16.48	16.48	16.48					\$	16.48	16.48	16.48	16.48

Exhibit 1
Range of Hourly MCPE Prices Used for MCPE Price Calculations
Source: ERCOT

Date	Month	Day	Hour Ending	Price				On Peak Price				OFF PeakPrice					
				NORTH	SOUTH	WEST	HOUSTON	NORTH	SOUTH	WEST	HOUSTON	NORTH	SOUTH	WEST	HOUSTON		
				Oncor-Dallas	AEP Central	AEP North	Center Point - HOUSTON	Oncor-Dallas	AEP Central	AEP North	Center Point - HOUSTON	Oncor-Dallas	AEP Central	AEP North	Center Point - HOUSTON		
1/2/2009	1	2	1	\$ 13.49	\$ 13.49	\$ 13.49	\$ 13.49							\$ 13.49	\$ 13.49	\$ 13.49	\$ 13.49
1/2/2009	1	2	2	\$ 12.97	\$ 12.97	\$ 12.97	\$ 12.97							\$ 12.97	\$ 12.97	\$ 12.97	\$ 12.97
1/2/2009	1	2	3	\$ 13.58	\$ 13.58	\$ 13.58	\$ 13.58							\$ 13.58	\$ 13.58	\$ 13.58	\$ 13.58
1/2/2009	1	2	4	\$ 15.57	\$ 15.57	\$ 15.57	\$ 15.57							\$ 15.57	\$ 15.57	\$ 15.57	\$ 15.57
1/2/2009	1	2	5	\$ 17.63	\$ 17.63	\$ 17.63	\$ 17.63							\$ 17.63	\$ 17.63	\$ 17.63	\$ 17.63
1/2/2009	1	2	6	\$ 18.68	\$ 18.68	\$ 18.68	\$ 18.68							\$ 18.68	\$ 18.68	\$ 18.68	\$ 18.68
1/2/2009	1	2	7	\$ 26.09	\$ 26.09	\$ 26.09	\$ 26.09	\$ 26.09	\$ 26.09	\$ 26.09	\$ 26.09						
1/2/2009	1	2	8	\$ 28.13	\$ 28.13	\$ 28.13	\$ 28.13	\$ 28.13	\$ 28.13	\$ 28.13	\$ 28.13						
1/2/2009	1	2	9	\$ 28.11	\$ 28.11	\$ 28.11	\$ 28.11	\$ 28.11	\$ 28.11	\$ 28.11	\$ 28.11						
1/2/2009	1	2	10	\$ 28.85	\$ 28.85	\$ 28.85	\$ 28.85	\$ 28.85	\$ 28.85	\$ 28.85	\$ 28.85						
1/2/2009	1	2	11	\$ 44.36	\$ 44.36	\$ 44.36	\$ 44.36	\$ 44.36	\$ 44.36	\$ 44.36	\$ 44.36						
1/2/2009	1	2	12	\$ 44.99	\$ 44.99	\$ 44.99	\$ 44.99	\$ 44.99	\$ 44.99	\$ 44.99	\$ 44.99						
1/2/2009	1	2	13	\$ 39.48	\$ 39.48	\$ 39.48	\$ 39.48	\$ 39.48	\$ 39.48	\$ 39.48	\$ 39.48						
1/2/2009	1	2	14	\$ 30.32	\$ 30.32	\$ 30.32	\$ 30.32	\$ 30.32	\$ 30.32	\$ 30.32	\$ 30.32						
1/2/2009	1	2	15	\$ 29.43	\$ 29.43	\$ 29.43	\$ 29.43	\$ 29.43	\$ 29.43	\$ 29.43	\$ 29.43						
1/2/2009	1	2	16	\$ 26.97	\$ 26.97	\$ 26.97	\$ 26.97	\$ 26.97	\$ 26.97	\$ 26.97	\$ 26.97						
1/2/2009	1	2	17	\$ 26.78	\$ 26.78	\$ 26.78	\$ 26.78	\$ 26.78	\$ 26.78	\$ 26.78	\$ 26.78						
1/2/2009	1	2	18	\$ 31.14	\$ 31.14	\$ 31.14	\$ 31.14	\$ 31.14	\$ 31.14	\$ 31.14	\$ 31.14						
1/2/2009	1	2	19	\$ 41.77	\$ 41.77	\$ 41.77	\$ 41.77	\$ 41.77	\$ 41.77	\$ 41.77	\$ 41.77						
1/2/2009	1	2	20	\$ 28.04	\$ 27.36	\$ 19.71	\$ 27.59	\$ 28.04	\$ 27.36	\$ 19.71	\$ 27.59						
1/2/2009	1	2	21	\$ 25.93	\$ 21.36	\$ (30.08)	\$ 22.93	\$ 25.93	\$ 21.36	\$ (30.08)	\$ 22.93						
1/2/2009	1	2	22	\$ 20.99	\$ 16.79	\$ (30.56)	\$ 18.23	\$ 20.99	\$ 16.79	\$ (30.56)	\$ 18.23						
1/2/2009	1	2	23	\$ 30.15	\$ 26.48	\$ (14.75)	\$ 27.74					\$ 30.15	\$ 26.48	\$ (14.75)	\$ 27.74		
1/2/2009	1	2	24	\$ 22.90	\$ 19.20	\$ (22.51)	\$ 20.47					\$ 22.90	\$ 19.20	\$ (22.51)	\$ 20.47		

Data for all 31 days in January, 2009 were used to calculate monthly average shown above.

Exhibit 1
Range of Hourly MCPE Prices Used for MCPE Price Calculations
Source: ERCOT

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Exhibit 1

Range of Hourly MCPE Prices Used for MCPE Price Calculations

Source: ERCOT

Example of Wires Charges at selected demand and load factors							
Month	Demand KW	Load Factor	AEP				
			Oncor	Central	AEP North	Houston	
1/1/2009	10	60%	\$ 123.16	\$ 168.61	\$ 172.72	\$ 97.96	
2/1/2009	10	60%	\$ 112.00	\$ 178.55	\$ 157.14	\$ 97.10	
3/1/2009	10	60%	\$ 123.16	\$ 196.86	\$ 172.72	\$ 98.27	
4/1/2009	10	60%	\$ 112.95	\$ 190.77	\$ 167.53	\$ 97.99	
5/1/2009	10	60%	\$ 116.46	\$ 196.86	\$ 172.72	\$ 98.27	
6/1/2009	10	60%	\$ 112.95	\$ 190.77	\$ 167.53	\$ 97.99	
7/1/2009	10	60%	\$ 116.46	\$ 196.86	\$ 172.72	\$ 98.27	
8/1/2009	10	60%	\$ 127.41	\$ 176.34	\$ 172.72	\$ 98.27	
9/1/2009	10	60%	\$ 124.56	\$ 171.18	\$ 167.53	\$ 98.22	
10/1/2009	10	60%	\$ 128.42	\$ 176.63	\$ 172.72	\$ 98.50	
11/1/2009	10	60%	\$ 124.56	\$ 171.18	\$ 167.53	\$ 97.13	
12/1/2009	10	60%	\$ 120.72	\$ 165.30	\$ 172.72	\$ 98.02	
1/1/2009	10	20%	\$ 46.24	\$ 61.38	\$ 65.41	\$ 92.08	
2/1/2009	10	20%	\$ 42.52	\$ 64.69	\$ 60.21	\$ 91.80	
3/1/2009	10	20%	\$ 46.24	\$ 70.81	\$ 65.41	\$ 92.40	
4/1/2009	10	20%	\$ 42.84	\$ 68.77	\$ 63.68	\$ 92.31	
5/1/2009	10	20%	\$ 44.01	\$ 70.81	\$ 65.41	\$ 92.40	
6/1/2009	10	20%	\$ 42.84	\$ 68.77	\$ 63.68	\$ 92.31	
7/1/2009	10	20%	\$ 44.01	\$ 70.81	\$ 65.41	\$ 92.40	
8/1/2009	10	20%	\$ 47.66	\$ 63.97	\$ 65.41	\$ 92.40	
9/1/2009	10	20%	\$ 47.38	\$ 62.25	\$ 63.68	\$ 92.54	
10/1/2009	10	20%	\$ 48.67	\$ 64.06	\$ 65.41	\$ 92.63	
11/1/2009	10	20%	\$ 47.38	\$ 62.25	\$ 63.68	\$ 91.45	
12/1/2009	10	20%	\$ 46.03	\$ 59.75	\$ 65.41	\$ 91.74	
1/1/2009	20	60%	\$ 155.28	\$ 230.98	\$ 121.81	\$ 155.62	
2/1/2009	20	60%	\$ 154.71	\$ 269.37	\$ 121.00	\$ 153.92	
3/1/2009	20	60%	\$ 155.28	\$ 287.49	\$ 121.81	\$ 156.26	
4/1/2009	20	60%	\$ 156.35	\$ 281.46	\$ 121.54	\$ 155.69	
5/1/2009	20	60%	\$ 156.54	\$ 287.49	\$ 121.81	\$ 156.26	
6/1/2009	20	60%	\$ 156.35	\$ 281.46	\$ 121.54	\$ 155.69	
7/1/2009	20	60%	\$ 156.54	\$ 287.49	\$ 121.81	\$ 156.26	
8/1/2009	20	60%	\$ 155.08	\$ 246.45	\$ 121.81	\$ 156.26	
9/1/2009	20	60%	\$ 161.09	\$ 242.37	\$ 121.54	\$ 156.15	
10/1/2009	20	60%	\$ 161.28	\$ 247.07	\$ 121.81	\$ 156.72	
11/1/2009	20	60%	\$ 161.09	\$ 242.37	\$ 121.54	\$ 153.97	
12/1/2009	20	60%	\$ 164.42	\$ 266.03	\$ 121.81	\$ 155.74	
1/1/2009	20	30%	\$ 152.35	\$ 165.81	\$ 117.64	\$ 146.82	
2/1/2009	20	30%	\$ 152.07	\$ 185.01	\$ 117.23	\$ 145.96	
3/1/2009	20	30%	\$ 152.35	\$ 194.08	\$ 117.64	\$ 147.45	
4/1/2009	20	30%	\$ 153.52	\$ 191.07	\$ 117.50	\$ 147.17	
5/1/2009	20	30%	\$ 153.61	\$ 194.08	\$ 117.64	\$ 147.45	
6/1/2009	20	30%	\$ 153.52	\$ 191.07	\$ 117.50	\$ 147.17	
7/1/2009	20	30%	\$ 153.61	\$ 194.08	\$ 117.64	\$ 147.45	
8/1/2009	20	30%	\$ 152.15	\$ 173.56	\$ 117.64	\$ 147.45	
9/1/2009	20	30%	\$ 158.26	\$ 171.84	\$ 117.50	\$ 147.63	
10/1/2009	20	30%	\$ 158.35	\$ 174.19	\$ 117.64	\$ 147.91	
11/1/2009	20	30%	\$ 158.26	\$ 171.84	\$ 117.50	\$ 145.45	
12/1/2009	20	30%	\$ 161.49	\$ 191.86	\$ 117.64	\$ 146.33	

Exhibit 1
Range of Hourly MCPE Prices Used for MCPE Price Calculations
Source: ERCOT

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