Iowa On-Site Generation Tariff Barrier Overview

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Iowa Environmental Council

Environmental Law & Policy Center
Protecting the Midwest's Environment and Natural Heritage

Prepared By:

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LEGAL NOTICE

EXECUTIVE SUMMARY

In the fall of 2010 the Midwest Clean Energy Application Center (CEAC) was asked by the Iowa Environmental Council (IEC) and the Environmental Law and Policy Center (ELPC) to undertake a study in order to determine the financial effects of standby rates in Iowa on distributed generation, especially combined heat and power (CHP) systems. Using the U.S. Environmental Protection Agencies' framework for rate analysis the CEAC evaluated the standby rates of all Iowa utilities to determine of the rates pose significant financial barriers to CHP implementation. According to the EPA, customer sited resources, and their respective standby rates, should avoid at least 90% of the otherwise applicable rate costs in order to be financially viable. The CEAC found that no utility in Iowa has an avoided rate greater than 81% and concludes that present standby rates discourage cleaner and more efficient technologies from being deployed in the state.

BACKGROUND

In 2001, the U.S. Department of Energy established the first of its kind Combined Heat and Power Regional Application Center (RAC) at the University of Illinois at Chicago. In 2003, seven other RACs were established to cover all 50 states. The goal of the RACs is to disseminate technological knowledge, provide hands on project assistance and create an educational infrastructure necessary to foster combined heat and power (CHP) as a widespread energy option. In 2008, the RACs were renamed "Clean Energy Application Centers" expanding their technology focus to include district energy and waste heat recovery. The US DOE Midwest Clean Energy Application Center (Midwest CEAC) services the 12 Midwest states of Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, and Wisconsin.

Through partnerships with businesses, non-profits and other concerned stakeholders, the Midwest CEAC creates coalitions to help implement CHP friendly policies. The Midwest CEAC also works closely with state energy offices throughout the region in order to lend their technical expertise. Currently, this center has been working closely with the ELPC and the IEC to examine the barriers towards CHP created by Iowa tariff structures.

During the past year Mid-American Energy chose not to include CHP technologies in their energy efficiency portfolio standard (EEPS). Instead, Mid-American decided that a tariff based approach to CHP would best suffice. While Interstate Power and Light (IPL) originally did not include CHP in their EEPS, IPL has since revised their stance to include CHP in their general energy efficiency incentive program. However, CHP projects are still required to use IPL's standard rates if they desire standby power.

Due to the provisions in their Settlement Agreements with the IEC and ELPC, Mid-American and IPL agreed to examine their tariff structures for possible barriers to CHP projects. Both investor owned utilities concluded that their tariffs posed no undue burden toward CHP implementation.

IEC and ELPC invited the Midwest CEAC to review the two Iowa utilities' CHP tariff structures to verify whether or not possible tariff barriers do exist in Iowa.

COMBINED HEAT AND POWER

A Combined Heat and Power (CHP) system is a form of distributed generation (DG) that generates at least a portion of the electricity requirements of a building, facility, and/or campus while recycling the thermal energy that would typically be exhausted from the electric generation process. This thermal energy can provide: space heating/cooling, process heating/cooling, dehumidification and/or increased electrical generation. CHP systems utilize commercially available state of the art technologies, and if properly sized and installed can provide:

- Reduced Energy Costs
- Improved Power Reliability
- Improved Power Quality
- Increased Energy Efficiency
- Improved Environmental Quality

CHP is all the more important when one examines the efficiency levels of large utility electrical generators. On average, two-thirds of fuel used to generate electricity in the U.S. is wasted by venting unused thermal energy into the atmosphere or dissipating it through cooling systems. While there have been impressive energy efficiency gains in other sectors of the economy since the oil price shocks of the 1970's, the average efficiency of power generation within the U.S. has remained around 34% since 1960.[1]

The average overall efficiency of generating electricity and heat by conventional systems is around 45 percent.[2] Figure 1 shows a diagram of Traditional/Conventional System delivering energy to a facility compared to a CHP system. By productively using the otherwise wasted thermal energy, CHP systems significantly increase energy utilization reaching efficiencies up to 80%. These generation systems are located in or near the associated facilities in order to better access and distribute the thermal energy. By utilizing electrical and thermal energy CHP systems save, on average, 40% on fuel usage compared to conventional systems delivering electric and thermal energy separately.[3]

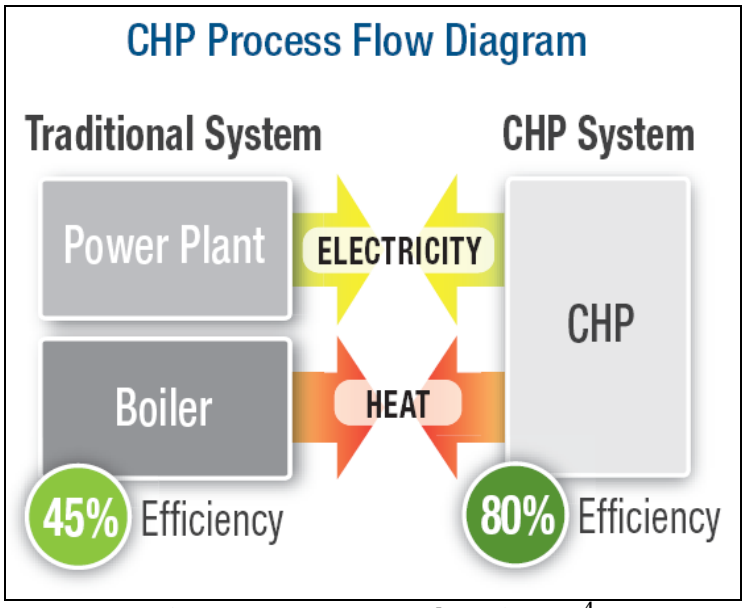

Figure 1: CHP Process Flow Diagram[4]

Customer-sited CHP reduces the amount of electricity generated/and/or purchased by the utility, potentially increasing the utility's generation, transmission and distribution system efficiency, particularly during peak periods when expensive marginal generation is used. Such systems can increase a grid's reliability and resiliency to disturbances and emergency episodes.

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[1] Oak Ridge National Laboratory, *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future*, by Anna Shipley et al, (Oak Ridge., 2008), 6.
[2] Ibid.
[3] Ibid.
[4] Ibid.

ELEMENTS OF ELECTRIC RATES

Full Requirements Rates

In order to understand how utility rates affect CHP implementation it is important to first understand how these rates work. Though electric rates differ immensely between utilities there exist three basic components general to all rates: a monthly (customer) charge, an energy charge and a demand charge.

Customer Charge: This is a fixed charge that covers the costs of administration which includes the cost of billing, metering, and customer service. In essence this is an access fee to the grid.

Energy Charge: This is a charge for the consumption of electricity (priced per kilowatt hour or kWh). Depending on the utility and the specific rate class the price of kWhs can differ between on, off and sometimes shoulder peak periods and between seasons.

Demand Charges: This is a charge for the level of demand a facility places on the grid (priced per kilowatt or kW). This charge is based on a peak demand interval of between 15 and 30 minutes during a given period, usually one month. Some utilities employ a demand ratchet that lock, for billing purposes, a facility's highest demand (or a percentage thereof) for a set period of several months to an entire year.

Customers that take their full electrical load from the utility are known as full requirements customers and are on rate schedules that largely resemble the rate structure discussed above. However, for customers with on-site generation a different rate structure is needed, one that recognizes the logistics of distributed generation. While DG systems can remove significant loads from the grid they must occasionally go offline for either scheduled or unscheduled outages. When this occurs the entire load of the facility is placed on the grid and must be served by the utility. Well timed outages (i.e. planned) rarely burden the utility as they occur during off-peak periods; however, standby rates are largely created to mediate the potential damages wrought from an ill-timed outage.

Standby Rates

Partial requirements service rates include provisions which address continuing electricity service for the portion of consumption not generated on-site in addition to providing service for moments when a generator is offline. Like full requirements rates, partial services rates can differ substantially from one utility to the next but also have similar categories of service: supplemental, unscheduled outage (backup), scheduled maintenance (maintenance) and a capacity reservation charge.

Supplemental Power: Supplemental service provides additional electricity for a customer whose onsite generation does not meet all of their consumption. Usually this service is provided under the otherwise applicable rate schedule.

Unscheduled Outage (Backup)Service: This service is taken when a customer's system must go offline immediately, usually for safety or maintenance reasons. This unexpected outage typically places a system's entire load on the grid. Since there is usually little to no advanced warning, this service may be taken during peak periods,

Scheduled Outage (Maintenance) Service: This service is taken when a customer's system must go offline for routine maintenance. Since this service is scheduled in advanced it is almost always taken during off-peak periods so as not to require the utility to use maximum capacity. Usually a customer must notify the utility between one and six months from the planned outage.

Capacity (or Reservation) Charge: This is a cost per kW of capacity reserved for backup or maintenance service. This monthly charge is intended to cover the cost, operation and maintenance of facilities to serve all customers at maximum loads.

DISCUSSION
TARIFFS – OPPORTUNITIES OR BARRIERS

Tariffs and rates can have a significant impact on CHP economics by affecting the amount of savings resulting from decreased energy purchases. The basic economic concept of implementing and operating an on-site CHP system is the tradeoff between the capital cost and daily operating costs (i.e. equipment O&M, reduced electricity and thermal energy purchases, additional fuel purchases). Utilities are required to provide standby power in case a facility's generation asset goes down suddenly. However, a major flaw in the design of standby rates is the assumption by the utilities that all DG systems will fail simultaneously, thus placing the full electric load of all customers onto the grid. Such a "worst case scenario" rate is based on the obligation of the utility to meet the combined total demand. This is often met with high cost resources resulting in high standby rates.

Utilities rarely create electric rates under the assumption that every light switch and appliance on the grid will be in operation simultaneously. It is overly conservative to make a similar assumption for DG systems. In fact, a survey of DG systems compiled for Oak Ridge National Laboratory (ORNL) found that reciprocating engines sized up to 3 MW and gas turbines sized up to 20 MW have an average availability of 95%.[5] Standby rates may penalize DG systems for the 5% (or less) a system is inoperable while failing to reward the other 95% of the time. When multiple DG systems operate on the same distribution circuit the probability of an unscheduled outage for all systems is lessened with each additional system.

In 2009 the Environmental Protection Agency (EPA) published a report identifying the elements of rate structures that appropriately charge utility customers with DG for the services they take, without creating economic barriers to DG."[6] In general, rate designs that do this include some, if not all, of the following:

- Peak demand charges that are not ratcheted (or at most, have a one month ratchet charge)
- Contract demand or reservation charges that are small in relation to the variable charges for peak demand and energy
- Energy based (instead of demand based) charges to collect capacity costs

[5] Energy and Environmental Analysis, Inc, *Distributed Generation Operation Reliability and Availability Database* (January 2004), ES-3.
[6] U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, *Standby Rates for Customer-Sited Resources* (Washington D.C., 2009), 2.

- Yield a significant retail rate savings per generated kWh over the purchased kWh rate

The use of peak demand ratchets is one of the more s problematic rate elements for CHP installations since they lock a customer's highest monthly demand for a longer set period of time, from a few months to a year. A yearly ratchet charges customers for capacity that is used but once per year. This practice significantly impacts those CHP systems that may go offline for maintenance or emergency reasons. A ratchet demand charge would include the increased facility demand from the CHP system going offline, therefore negating a large portion of the financial savings generated with the intent to reduce the facility's electric demand from the grid. In this instance, a customer would essentially pay the same demand charge before and after CHP installation even though CHP would sharply reduce the average monthly demand. As ORNL has demonstrated through its research, even the best maintained CHP systems will need to be periodically shut down.

In addition, large contract demand or reservation charges are also problematic in that they replace a per kW demand charge with a larger per kW reservation charge. This impacts the financial savings of on-site CHP operations since the amount of demand in kW lost will always be equal to the amount of needed reservation capacity.

EPA's findings in the 2009 report are consistent with the understanding that the economics of onsite generation are based on reduced electricity purchases. When energy charges can cover capacity related costs, the reduction in electricity purchases will be directly commensurate with the reduction in utility bills.

MODELLING TARIFFS

Using the aforementioned EPA report as a framework, the Midwest CEAC created computer models used to help analyze the financial effects of standby rates for CHP sites in the Iowa electric utility service territories of IPL and Mid-American. In order to model a "typical" CHP system, the CEAC used information provided by the previously mentioned ORNL survey. This report titled *Distribution Generation Operational Reliability and Availability Dataset*, analyzed the operational parameters of many CHP systems throughout the country. The CEAC chose modeling parameters representative of a "hypothetical" small-to-medium sized CHP system.

The operational parameters and assumptions modeled include:

- CHP Generation: 1,600 kW operating 24/7
- Facility peak summer demand: 3,000 kW
- Facility peak shoulder demand: 2,500 kW
- Facility peak winter demand: 2,200 kW
- A day is divided into 12 hours for both on and off peak pricing
    - 22 days out of a 30 day month are thusly divided into the 12 hours for on and off peak pricing
    - The remaining 8 days are solely considered off peak periods (representing weekends)
- System online 98.22% of the year, translating to 8604 hours.
- System scheduled outage 1.12% of the year, translating to 98 hours. (roughly 3-4 occurrences per year)
- System forced outage 0.85% of the year, translating to 74 hours (roughly 2 occurrences per year)
- All outages, whether scheduled or forced, are presumed to occur in different months throughout the year.
- We have modeled a worse case, forced outage during peak summer demand scenario.
- All standby demand was modeled at the lowest possible increment allowed under each utility

The utility rates used for this model are those that are best fitted to such installations. In general, these rates would apply to smaller industrial or larger commercial facilities. In addition, some hospitals and community colleges could fit into this category as well. The appendix contains the utility rates used in the modeling for this report.

AVOIDED RATE AS EVALUATION MEASURE

The EPA's concept of avoided rate, described in their 2009 report, was used as the evaluation benchmark when analyzing the financial impacts of standby rates on DG systems. The avoided rate compares the cost per kWh on a full requirements tariff to the avoided cost per kWh on a standby tariff. The avoided cost is a kWh price for the electricity *not* purchased due to on-site generation (money not paid to utility / electricity not purchased = avoided cost per kWh). This concept is important because, ideally, the reduction in electricity price should be commensurate with the reduction in purchased electricity. When the avoided rate closely matches the full requirements rate, the user experiences increased savings.

For example, a hypothetical facility purchases 1,000,000 kWh per year from the utility at an aggregate cost of 10¢ per kWh for a total cost of $100,000. Say this same facility installs a CHP system that reduces their need for purchased electricity to 500,000 kWh per year. In an ideal economic situation the annual bill would be half the normal bill, or $50,000. Under this ideally constructed scenario the avoided cost from the 500,000 kWh not purchased would be 10¢ per kWh ($50,000/500,000 kWh = 10¢/kWh). Thus, this situation would have an avoided rate of 100% the full requirements rate (10¢/kWh / 10¢/kWh = 100%). Unfortunately, an avoided rate of 100% of the full requirements rate is rare in existing utility rate structures. According to the EPA standby rate study, avoided costs that are at least 90% of the full service retail rate provide adequate financial savings for CHP systems and are considered the desired benchmark in this report's modeling methodology.

As the models below demonstrate, none of the analyzed Iowa utilities have avoided rates for standby charges greater than 81%. These rates actively prevent CHP systems from achieving the desired savings necessary to make projects more economically viable. Utilities serious about encouraging the implementation of distributed generation CHP projects need to ensure their avoided rates are 90% and greater, demonstrating fair standby rates.

UTILITY MODELING RESULTS

MID-AMERICAN ENERGY

Mid-American divides its Iowa service territory into three service areas all conforming to geographic areas of the state: Eastern, Northern and Southern. Unlike other utilities with subsidiaries, the three geographic service areas of Mid-American have radically different tariff structures. Though the tariffs structures are different they all inhibit cost effective CHP generation by imposing peak demand ratchets and including outage demand charges in their ratchet structure.

EASTERN MID-AMERICAN

The eastern subsidiary of Mid-American has the vaguest language in describing its standby rate. The modeling analysis incorporated Rate No. 42 as the full requirements rate and Rider No. 8 as the partial service rate.[7] The CEAC found the most significant barriers to be:

- 75% peak summer demand ratchet (or 50% yearly ratchet, whichever is greater)
- No separate demand rate for maintenance and backup power
- Minimum monthly charge is the demand charge and the demand charge multiplied by 200kWh charged per kWh.[8]

Under Rider No 8: Auxiliary and Standby Electric Service a customer can negotiate the amount of supplemental power needed; demand charges will then be issued accordingly. However, if actual demand exceeds the contract (negotiated) demand, the higher of the demands (actual vs. negotiated) will subsequently be used. Since a CHP system will may go off-line 5 to 6 times per year (includes both scheduled and unscheduled outages) the additional demand created by maintenance or backup power will be ratcheted for an entire year.[9] This rate structure not only reduces customer savings, but inevitably charges a customer similar demand charge as if they had not implemented a CHP system.

Mid-American East has an avoided rate of 74.71%, far lower than EPA guidelines stipulate to make projects financially viable.

Mid-American Eastern System	Full Requirements	Partial Requirements
Energy Purchased(kWh)	16,660,800 kWh	3,034,644 kWh
Portion Backup Energy		151,536 kWh
Portion Maintenance Energy		46,308 kWh
Facilities Charge	$240.00	$240.00
Demand Charges	$241,232.50	$134,740.00
Energy Charges	$566,813.50	$188,002.04
Standby Charges	n/a	n/a
Alternative Energy Production Rider	$3,665.38	$667.62
Energy Efficiency Cost Recovery	$37,820.02	$6,888.64
Total Charges	**$849,771.39**	**$330,538.30**
kWh Difference	**13,626,156 kWh**	
Monetary Difference	**$519,233.09**	
Average rate for purchased power	$0.05100	$0.10892
Average avoided rate		$0.03811
Avoided rate as a percentage of average retail service rate	**74.71%**	

[7] http://www.midamericanenergy.com/include/pdf/rates/elecrates/iaelectric/ia-elec.pdf
[8] http://www.midamericanenergy.com/include/pdf/rates/elecrates/iaelectric/ia-elec.pdf
[9] Energy and Environmental Analysis, Inc, ES-3.

NORTHERN MID-AMERICAN

Though slightly more favorable than the Eastern system, the Northern subsidiary still presents formidable barriers to CHP implementation. This model used rates LPN/APN: Large General Service as the full requirements rate and Rider No. 1 and the CAP schedule as the partial service rates. The CEAC found the most significant barriers to be:

- 100% peak ratchet for supplemental power
- Backup demand included in supplemental demand ratchet
- High standby demand charges

The 100% peak ratchet impacts all tariff rates, including CHP and should be addressed. Combined with the lack of backup power provisions the situation becomes similar to that previously discussed in the Eastern Mid-American service territory. In this situation one unplanned outage could significantly offset the potential savings for an entire year.

The standby demand charge is actually higher than all but two regular rate schedule demand charges. In other words, some customers might be paying more for their maintenance demand charge on their new partial requirements rate than they were on their previous rate. The only rates that charge more for demand are Large General Service Time-of-Use metering rates which cater towards large industrial facilities.

Mid-American North has an avoided rate of 80.34%, far lower than EPA guidelines stipulate to make projects financially viable.

Mid-American Northern System	Full Requirements	Partial Requirements
Energy Purchased(kWh)	16,660,800 kWh	3,009,984 kWh
Portion Backup Energy		43,296 kWh
Portion Maintenance Energy		129,888 kWh
Facilities Charge	$2,400.00	$2,400.00
Demand Charges	$114,840.00	$102,820.00
Energy Charges	$463,115.86	$71,638.42
Standby Charges	n/a	$28,155.39
Alternative Energy Production Rider	$3,665.38	$662.20
Energy Efficiency Cost Recovery	$37,820.02	$6,832.66
Total Electrical Charges	**$621,841.25**	**$212,508.66**
kWh Difference	**13,650,816 kWh**	
Monetary Difference	**$409,332.58**	
Average rate for purchased power	$0.03732	$0.07060
Average avoided rate	n/a	$0.02999
Avoided rate as a percentage of average retail service rate	**80.34%**	

SOUTHERN MID-AMERICAN

The rate structures for the Southern system are most similar to the Northern system. This model used rate LPS/LPC/APS as the full requirements rate and Rider No. 1 as the partial requirements rate. The CEAC identified the following barriers in standby rates,

- Backup demand included in supplemental demand ratchet
- Demand based approach to standby charges
- 6 month notification to schedule maintenance

The backup demand situation in Southern Mid-American is similar to the northern subsidiary and needs no further explanation. However, the two systems have widely differing results partly due to the increased full requirements demand costs in the southern system. These increased costs widen the gap between the average full requirements rate and the avoided rate making it more difficult for a CHP system to obtain the 90% avoided rate savings threshold.

The 6 month timeframe for scheduling maintenance power is considered far too long a period. If repairs are crucial and pressing the only option available for a customer is to transfer their entire load to the grid much as they would during emergency power use. The CEAC believes this unfairly burdens a DG site.

Mid-American South has an avoided rate of 80.54%, far lower than EPA guidelines stipulate to make projects financially viable.

Mid-American Southern System	Full Requirements	Partial Requirements
Energy Purchased(kWh)	16,660,800 kWh	3,072,528 kWh
Portion Backup Energy		46,308 kWh
Portion Maintenance Energy		189,420 kWh
Facilities Charge	$2,400.00	$2,400.00
Demand Charges	$209,280.00	$113,852.00
Energy Charges	$465,373.82	$101,528.86
Standby Charges	n/a	$21,100.00
Alternative Energy Production Rider	$3,665.38	$675.96
Energy Efficiency Cost Recovery	$37,820.02	$6,974.64
Total Electrical Charges	**$718,539.21**	**$246,531.45**
kWh Difference	**13,588,272 kWh**	
Monetary Difference	**$472,007.75**	
Average rate for purchased power	$0.04313	$0.08024
Average avoided rate	n/a	$0.03474
Avoided rate as a percentage of average retail service rate	**80.54%**	

INTERSTATE POWER AND LIGHT

Similar to Mid-American, Interstate Power and Light's standby rate poses a significant financial barrier to distributed generation implementation. The analysis model incorporates the Electric Large General Service Usage Rate as the full requirements rate and Rider SSPS as the partial requirements rate.

The Midwest CEAC found the most significant barriers under IPL tariffs to be,

- 5 Year Contract Requirement with a penalty for leaving before a 10 year period
- A 75% peak summer demand ratchet
- High reservation and supplemental demand charges
- Demand based standby charge

Though the least problematic issue, the 5 year contract and 10 year penalty negatively impacts CHP facilities by forcing the customer to potentially pay an exit fee if for some reason the system or business fails. Though many systems stay on-line for at least 10 years some do not and are shut down due to less expensive resources of energy, mechanical failures, lower than anticipated energy savings, and/or reduced business. The financial penalty is created as a guaranteed return for the investment into a customer's interconnection, however, a more responsible approach would be for the customer to pay the rest (if any) of the demonstrated cost of the utilities portion of the interconnect.

The 75% peak demand ratchet means that monthly demand charges for supplemental power will never be lower than 75% of the highest summer charge. During winter months when demand is far lower, this ratchet ensures that facilities are still hit with a large demand charge. Other more favorable rate structures remove the ratchet provision from supplemental power.

The CEAC found that contract reservation and supplemental demand charges are high in relation to the otherwise applicable rate charges. Our analysis model found that standby demand charges (including reservation charges) only decreased 36% in the summer and 24% in the winter when a facility reduced its energy consumption by 64% (i.e. generated 64% of peak load). The best rates are those that closely match the percentage decrease in peak load.

IPL's standby rate is primarily comprised of demand charges that energy consumption charges. In the summer, demand charges make up roughly 69% of the rate whereas in the winter they make up as much as 78%. Since CHP savings are generated through decreased electricity purchases, these high demand charges make it more difficult for a CHP system to break even on savings. A fairer system involves charging primarily for the energy consumed even if that energy is priced at a premium.

Interstate Power and Light has an avoided rate of 79.78%, far lower than EPA guidelines stipulate to make projects financially viable.

Interstate Power & Light System	Full Requirements	Partial Requirements
Energy Purchased(kWh)	16,660,800 kWh	3,026,220 kWh
Portion Backup Energy		0 kWh
Portion Maintenance Energy		189,420 kWh
Facilities Charge	$213.60	$1,020.00
Demand Charges	$431,530.50	$196,171.50
Energy Charges	$216,474.34	$46,685.66
Standby Charges	N/A	$115,738.06
Energy Efficiency Cost Recovery	$415,475.28	$78,103.74
Energy Adjustment Clause (2010)	$413,637.68	$75,131.96
Total Electrical Charges	**$1,477,331.40**	**$512,850.92**
kWh Difference	**13,634,580 kWh**	
Monetary Difference	**$964,480.48**	
Average rate for purchased power	$0.089	$0.169
Average avoided rate		$0.071
Avoided rate as a percentage of average retail service rate	**79.78%**	

CONCLUSION

All of the Iowa investor owned utilities analyzed in this document have less than favorable avoided rates for self-generation customers. The results of the tariff and on-site generation modeling performed by the Midwest CEAC are as follows:

- Eastern Mid-American: 74.71%
- Northern Mid-American: 80.34%
- Southern Mid-American: 80.54%
- Iowa Power & Light: 79.78%

Avoided costs that are below 90% of the full service retail rate percentage provide inadequate financial savings. One of the largest structural culprits to self-generating customers that contribute to the low avoided rate scores is demand ratcheting, which is apparent throughout all of IPL's and Mid-American's rate tariffs.

Another reason for these standby rates being unfavorable is their proportionate reliance on demand based charges (which are ratcheted) instead of energy charges. Under the Mid-American South tariffs even though our model reduced electrical purchases by 82% the yearly bill only decreased by 65%. This is a direct result of the heavy use of demand charges instead of more energy specific charges; under their full requirements rates demand charges comprise 30% of a yearly bill whereas they comprise upwards of 50% for a partial service customer. This is common for all Mid-American systems. Explaining these disproportionate figures can be tied to the yearly ratchets implemented by the utilities. If the Iowa utilities modeled in this report were to remove their yearly ratchets for self-generating customers, economic savings would be greatly increased and would therefore help make Iowa a more attractive market for the implementation of CHP and other on-site DG technologies.

Why should a DG system pay both supplemental demand and reservation demand charges when they cover essentially the same demand load? Utilities typically argue that the increased standby charges issued through ratchets are intended to cover the costs of maintaining the energy capacity necessary in the case of a system failure. However, as is witnessed throughout the U.S., rates can be created in a way that safeguards distribution grids while creating savings for well running DG systems. The EPA CHP Partnership found in their report that Portland General Electric's Rate 75 (partial requirements) and Rate 89 (full requirements) both demonstrate ideal examples of rate construction that can aid in CHP implementation.

Combined heat and power technologies have the ability to offer more efficient, cleaner and potentially safer energy. The benefits are vast and positively affect both rate payers and utilities alike. While more top down policy approaches are useful to increase CHP implementation, unreasonable utility rates can create barriers that make even the most technically sensible projects difficult to make sense financially.

APPENDIX A: Tariffs
A.1: Mid American East

MidAmerican ENERGY

MIDAMERICAN ENERGY COMPANY
Electric Tariff No. 1
Filed with the Iowa Utilities Board

8th Revised Sheet No. E-8
Canceling 7th Revised Sheet No. E-8

RATE NO. 42 COMMERCIAL AND INDUSTRIAL SERVICE

Available to any East System commercial or industrial customer.

NET MONTHLY RATE:

Basic Service: $20.00 per month

Billing Demand Charge:

	Summer	Winter
For the first 300 kW	$ 9.80 per kW	$7.55 per kW
For all over 300 kW	$ 9.15 per kW	$6.95 per kW

Energy Charge: (Subject to tax adjustment, AEP and energy efficiency cost recovery adjustment, and carbon reduction cost recovery) D/N

For the first 300 hours' use per month of the kilowatt billing demand applicable for the month:

	Summer	Winter
For the first 6,000 kWh	5.187¢ per kWh	4.787¢ per kWh
For all over 6,000 kWh	3.937¢ per kWh	3.537¢ per kWh

For the excess over 300 hours' use per month of the kilowatt billing demand applicable for the month:

3.037¢ per kilowatthour

Summer - Applicable during the four monthly billing periods of June through September.

Winter - Applicable during the eight monthly billing periods of October through May.

Issued: August 25, 2010
Issued by: Naomi G. Czachura
Vice President

Effective: October 1, 2010

RATE NO. 42 COMMERCIAL AND INDUSTRIAL SERVICE (Cont.)

Minimum Charge:

The minimum monthly bill shall be the basic service charge, applicable energy charges for the month, and billing demand charges for the month.

LATE PAYMENT CHARGE:

A late payment charge of one and one-half percent per month of the past due amount will be added to the amount of the bill where payment is not made within twenty days of the rendition of the bill.

ADJUSTMENT FOR PRIMARY METERING:

Where service is furnished at primary voltage, the Company may, at its option, install the metering equipment on the high-voltage side of the service transformers. In that event, the kilowatt demand and the kilowatthours metered shall be decreased by one and two-tenths percent (1.2%).

MAXIMUM DEMAND:

The maximum kilowatt demand in any month shall be the highest thirty-minute kilowatt demand established during the month.

BILLING DEMAND:

The billing demand for any month shall be the greater of: (a) the maximum kilowatt demand in such month; (b) 75 percent of the customer's maximum demand applicable for billing in the billing months of June, July, August, and September during the preceding eleven-month period; (c) 50 percent of the customer's maximum demand applicable for billing in all other months during the preceding eleven-month period; or (d) ten kilowatts.

D

RATE NO. 42 COMMERCIAL AND INDUSTRIAL SERVICE (Cont.)

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GENERAL:

Service hereunder is subject to the Rules and Regulations of the Company and applicable Riders included in this electric tariff schedule.

RIDER NO. 8 AUXILIARY AND STANDBY ELECTRIC SERVICE

Available to any customer being served under Rate Nos. 41, 42, and 53 for auxiliary or standby electric service who has installed on his premises privately-owned equipment for power production purposes and contracts with the Company to use such service. Contracts will be made for this service provided the Company has sufficient capacity available in production, transmission, and distribution facilities to provide such service at the location where the service is requested.

Customer-owned power production equipment shall not operate in parallel with the Company's system until the installation has been inspected by an authorized Company representative and final written approval is received from the Company to commence parallel operation.

Electric service and billing for such service shall be according to provisions contained in the applicable rate schedule, subject to the following Billing Demand and Minimum Charge modifications:

BILLING DEMAND:

The customer shall contract for a specific kilowatt demand sufficient to meet the customer's minimum requirements, but not less than the minimum demand specified in the applicable rate schedule, which kilowatt demand shall be the minimum billing demand for purposes of determining the monthly charges under the applicable rate schedule. In the event the contract demand is exceeded in any month by a higher billing demand (determined as provided in the applicable rate schedule), such higher demand shall be considered as the new billing demand for the month. The billing demand thereafter shall be according to the provisions in the applicable rate schedule, but shall not be less than the contract demand.

MINIMUM CHARGE:

The minimum charge for any month's service shall be the demand charge for the applicable billing demand plus an amount equal to the energy charge for 200 kilowatthours per kilowatt of such billing demand.

RIDER NO. 8 AUXILIARY AND STANDBY ELECTRIC SERVICE (Cont.)

The amount by which the net bill payable in any month under the applicable rate schedule, using the applicable billing demand and the actual energy consumed, is less than the minimum charge provided for herein and paid for in such month is hereinafter called the deficiency. In the final billing month of each contract year, deficiencies paid by the customer during the contract year shall be credited by the Company against payments made hereunder in excess of the minimum charges during such contract year. These credits shall not exceed the total of the deficiencies paid by the customer during the contract year.

A.2: Mid-American North

MidAmerican ENERGY

MIDAMERICAN ENERGY COMPANY
Electric Tariff No. 1
Filed with the Iowa Utilities Board

5th Revised Sheet No. N-24
Canceling 4th Revised Sheet No. N-24

CLASS OF SERVICE: **Large General Service, Base Use at Primary Voltage Price Schedules LPN and APN**

AVAILABLE: Applicable in all of the Company's service territory (North System only).

APPLICABLE: At the option of the customer, to all electric service required on premises by customer, subject to applicable terms and conditions of the Company's Electric Service Policies and Electric Rate Application. Applicable to standby or supplementary service (under written agreement only) in conjunction with applicable Company riders for such service.

CHARACTER: Alternating current: 60 Hz; single or three phase, at primary voltages offered by the Company, as further described in the Company's Electric Policies and Electric Rate Application.

PRICES:	**Summer**	**Winter**
Service Charge per meter	$200.00	$200.00
Demand Charge times kW of measured demand for customers with primary metering, but not less than 200 kW	$3.68/kW	$3.19/kW
Reactive Demand Charge per kVAR of reactive demand in excess of 50% of billing demand	$0.49/kVAR	$0.49/kVAR
Energy Charge: First 250 hours x kW of demand Next 150 hours x kW of demand Over 400 hours x kW of demand	 $0.03647/kWh $0.02577/kWh $0.01837/kWh	 $0.03157/kWh $0.02577/kWh $0.01837/kWh
Transformer Ownership Credit	$0.30/kW	$0.30/kW
Tax Adjustment: Subject to the Tax Adjustment. See Sheet No. C-2.		
AEP and Energy Efficiency Cost Recovery Adjustments: These will appear as charges to the bill. They are calculated on a per kWh basis. See Sheet Nos. C-1 and C-3 for more details.		
Rider CR Carbon Reduction Cost Recovery: This is calculated on a per kWh basis. See Sheet No. B-5 for more details.		

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Issued: August 25, 2010
Issued by: Naomi G. Czachura
Vice President

Effective October 1, 2010

Large General Service, LPN and APN, continued

DEMAND: The kW as shown by or computed from the readings of the Company's demand meter for the 15-minute period of the customers' greatest use during the month, determined to the nearest kW, but not less than 200 kW.

REACTIVE DEMAND: The kVAR as shown by or computed from the readings of the Company's reactive demand meter, determined to the nearest kilovar. The customer is not billed for reactive demand unless the customer's power factor is less than 89.44% lagging, equivalent to situations where kVAR of reactive demand exceed 50 percent of billing demand. The power factor will be based on the highest kW demand and kVAR demand for the billing period.

SEASONAL PROVISION: Summer and winter periods are defined as: Summer, June through September billing periods; and Winter, October through May billing periods.

TRANSFORMER OWNERSHIP CREDIT: Should the customer elect to furnish transformers that would normally be furnished by the Company, the customer will receive a credit of $0.30 per kW of billing demand.

MINIMUM BILL: The service charge, plus the highest summer demand during the past 12 months multiplied by the demand charge, plus the cost of fuel (including amounts in base prices plus amounts in the energy cost adjustment), less the transformer ownership credit, plus the tax, energy efficiency cost recovery adjustments, AEP, and carbon reduction cost recovery. T N

TAX ADJUSTMENT: This rate is subject to the Tax Adjustment; see Sheet No. C-2.

PAYMENT: Bills are due and payable within twenty days from the date the bill is rendered to the customer. When not so paid the bill is delinquent and a late payment charge, which is equal to 1.5 percent per month of the past due amount or such portion that remains unpaid after each subsequent month, shall be added.

MidAmerican ENERGY

MIDAMERICAN ENERGY COMPANY
Electric Tariff No. 1
Filed with the Iowa Utilities Board

Original Sheet No. N-34

CLASS OF SERVICE: **Supplementary Power Contract Service - Price Schedule CAP (Contract Power)**

Application

To any commercial and industrial customer and to any public authority whose total load requirement is 10 MW or less and who:

1. Owns and/or operates cogeneration and/or small power production facilities in excess of 100 kW capability which meet the requirements of qualifying facilities pursuant to Title 18 of the Code of Federal Regulations, Part 292, Subpart B; and
2. Executes a contract for service hereunder with the Company for a term of not less than five years. The customer may extend the term of the contract for an additional term of five years, upon giving written notice to the Company during the fourth year of the contract, or any extension thereof.

Emergency Power and Energy

Emergency power and energy is that power and energy required by customer to meet a temporary need due to an emergency breakdown of its generating facilities. Company shall supply emergency energy subject to the availability of such power and energy and further subject to the condition that such supply will not result in impairment of or serious jeopardy to service in the Company's system. Customer agrees to notify the Company by telephone as soon as possible when emergency conditions exist and also upon restoration to normal service operations and to confirm notices in writing within 48 hours. Emergency power and energy is not available during periods when the Company has requested customer limit service to its firm contract demand level unless customer has notified Company of the emergency situation two hours prior to the Company's request for customer to limit service to the firm contract level.

Quantity used shall be determined by multiplying the contract demand (as set forth in customer's contract) for emergency energy by the total elapsed time such energy is used.

Maintenance Power and Energy

Maintenance power and energy is that power and energy requested by customer to meet a temporary need due to prearranged or scheduled maintenance of its generating facilities. Maintenance power and energy shall be available for consecutive days only and for periods not longer than 45 consecutive days and shall not be scheduled except by mutual agreement between customer and the Company. If customer desires maintenance power and energy, it shall request the amount required, probable load factor, period required, and an estimate of hourly amounts. The quantity once agreed upon shall not be subject to adjustment during said period, except by mutual agreement.

Firm and Interruptible Power and Energy

Firm power is that block of firm contract demand as specified in the contract. Demand in excess of firm contract demand is considered interruptible. Energy accompanying both firm and interruptible demands and excluding emergency and maintenance energy will be billed at either the on-peak or off-peak rate.

Issued: November 9, 1995
Issued by: Brent E. Gale
Vice President-Law and Regulatory Affairs

Effective December 15, 1995

CLASS OF SERVICE: Supplementary Power Contract Service - Price Schedule CAP (con't)

Definition of Peak Periods

The on-peak period is defined as those hours between 7:00 a.m. and 11:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The off-peak period is defined as all other hours. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

Penalty for Failure to Curtail

The Company in its sole discretion may curtail service hereunder to contract demand upon 15 minutes' notice to the customer. In the event customer fails to limit service to its firm contract demand level upon 15 minutes' notice from the Company, customer shall pay in addition to all other charges hereunder a penalty of $30 per kW. Such penalty shall be applied during each period the Company has requested customer to limit its load to firm contract demands and shall be computed by multiplying $30 times the excess of the 15-minute demand as measured by the Company's meter less the amount of the firm contract demand, less any maintenance and/or emergency power supplied by the Company during the 15-minute period.

Notwithstanding the previous paragraph, the Company reserves the right to assure itself that any agreed-upon interruptible load can be readily interrupted or curtailed upon 15 minutes' notice. In the event customer fails to limit service, upon proper notice, Company reserves the unilateral right to terminate service to customer. The Company shall have no liability to the customer or any other person, firm, or corporation for any loss, damage, or injury by reason of any interruption or curtailment as provided herein.

Service Regulations

The Company's Service Electric Policies shall apply.

Special Conditions

The customer shall furnish, if requested, suitable space on his premises for Company's transforming and switching equipment. The customer shall also provide access to such equipment by Company personnel.

The Company shall not be required to supply electric service to the customer for purposes which, due to their fluctuation in load, may cause impairment to the general services of the Company.

CLASS OF SERVICE: Supplementary Power Contract Service - Price Schedule CAP (con't)

Monthly Price Schedule

Facilities Charge:	As set forth in customer's contract
Demand Price:	$5.30 per month per kW of firm contract demand.
Energy Price:	On-Peak Rate $0.03077 per kWh Off-Peak Rate $0.01647 per kWh

Emergency Energy

The price shall be $0.06487 per kWh or the incremental energy cost plus 10%, for the period of use, whichever is greater.

Maintenance Power and Energy

Price: $0.23490 per kW per day D
$0.04307 per kWh D

Power Factor Adjustment

A charge of $1.50 shall be made for each kVAR by which the customer's reactive demand at the time of the customer's maximum demand in kVARs is greater than 32 percent of the customer's maximum kW demand (as measured by Company's metering equipment) in that billing period.

Bill Payment Provision

The price is net. A late payment charge of 1.5% per month shall be added to the past-due amount if the bill is not paid by the due date.

Clauses

Subject to the tax adjustment; see Sheet No. C-2.
Subject to the AEP, energy efficiency cost recovery and carbon reduction cost D/N
recovery adjustments; see Sheet Nos. C-1, C-3 and B-5.10. D/N

Purchases of Capacity and Energy By Company

As set forth in customer's contract and subject to the waiver granted by the IUB in Docket No. WRU-92-38-154, issued June 29, 1992.

A.3: Mid-American South

MidAmerican ENERGY

MIDAMERICAN ENERGY COMPANY
Electric Tariff No. 1
Filed with the Iowa Utilities Board

6th Revised Sheet No. S-24
Canceling 5th Revised Sheet No. S-24

CLASS OF SERVICE: **Large General Service, Base Use at Primary Voltage**
Price Schedules LPS, LPC and APS

AVAILABLE: Applicable in all of the Company's service territory (South System only).

APPLICABLE: At the option of the customer, to all electric service required on premises by customer, subject to applicable terms and conditions of the Company's Electric Service Policies and Electric Rate Application. Applicable to standby or supplementary service (under written agreement only) in conjunction with applicable Company riders for such service.

CHARACTER: Alternating current: 60 Hz; single or three phase, at primary voltages offered by the Company, as further described in the Company's Electric Service Policies and Electric Rate Application.

PRICES:	**Summer**	**Winter**
Service Charge per meter	$200.00	$200.00
Demand Charge times kW of measured demand for customers with primary metering, but not less than 200 kW	$6.26/kW	$5.59/kW
Reactive Demand Charge per kVAR of reactive demand in excess of 50% of billing demand	$0.49/kVAR	$0.49/kVAR
Energy Charge: First 250 hours x kW of demand Next 150 hours x kW of demand Over 400 hours x kW of demand	 $0.03737/kWh $0.02567/kWh $0.01827/kWh	 $0.03337/kWh $0.02567/kWh $0.01827/kWh
Transformer Ownership Credit	$0.30/kW	$0.30/kW
Tax Adjustment: Subject to the Tax Adjustment. See Sheet No. C-2.		
AEP and Energy Efficiency Cost Recovery Adjustments: These will appear as charges to the bill. They are calculated on a per kWh basis. See Sheet Nos. C-1 and C-3 for more details.		
Rider CR Carbon Reduction Cost Recovery: This is calculated on a per kWh basis. See Sheet No. B-5 for more details.		

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DEMAND: The kW as shown by or computed from the readings of the Company's demand meter for the 15-minute period of the customer's greatest use during the month, determined to the nearest kW, but not less than 200 kW.

Issued: August 25, 2010
Issued by: Naomi G. Czachura
Vice President

Effective October 1, 2010

Large General Service, LPS, LPC, and APS, continued

REACTIVE DEMAND: The kVAR as shown by or computed from the readings of the Company's reactive demand meter, determined to the nearest kilovar. The customer is not billed for reactive demand unless the customer's power factor is less than 89.44% lagging, equivalent to situations where kVAR of reactive demand exceed 50 percent of billing demand. The power factor will be based on the highest kW demand and kVAR demand for the billing period.

SEASONAL PROVISION: Summer and winter periods are defined as: Summer, June through September billing periods; and Winter, October through May billing periods.

TRANSFORMER OWNERSHIP CREDIT: Should the customer elect to furnish transformers that would normally be furnished by the Company, the customer will receive a credit of $0.30 per kW of billing demand.

MINIMUM BILL: The service charge plus the highest summer demand during the past 12 months multiplied by the demand charge, plus the cost of fuel (including amounts in base prices plus amounts in the energy cost adjustment), less the transformer ownership credit, plus the tax, energy efficiency cost recovery adjustments, AEP, and carbon reduction cost recovery. N

TAX ADJUSTMENT: This rate is subject to the Tax Adjustment; see Sheet No. C-2.

PAYMENT: Bills are due and payable within twenty days from the date the bill is rendered to the customer. When not so paid the bill is delinquent and a late payment charge, which is equal to 1.5 percent per month of the past due amount or such portion that remains unpaid after each subsequent month, shall be added.

CLASS OF SERVICE: **Rider No. 1 to Electric Large General Service - Standby and Supplementary Service**

PRICE SCHEDULES: Same as applicable price schedules.

AVAILABLE: By written contract, in the North and South Systems of the Company's electric service area.

APPLICABLE: To standby and supplementary electric service to a customer's, installation normally supplied wholly or partially by a source of power, either electrical or mechanical, other than the Company's electric system. Operation of such other source of power in parallel with Company's system will be permitted only for qualifying cogenerator and small power producer facilities or for qualifying alternate energy producers and small hydro facilities, as defined by the Public Utilities Regulatory Policies Act of 1978 or by applicable laws of the State of Iowa. Standby and supplemental service will be supplied under this rider in conjunction with Large General Service Price Schedules, but for not more than 10,000 kW.

NET MONTHLY RATE: Charges for service hereunder will be at the prices specified in the price schedules to which this Rider is applicable, subject to the following additions and modifications:

Standby Service Charge:

Summer Price	Winter Price
$1.55	$1.15 per kW for all kW of Standby Capacity

Tax Adjustment: This rate is subject to the Tax Adjustment; see Sheet No. C-2.

Minimum Bill: The sum of (1) the service charge, (2) the demand charge calculated at the rate for the current season for the greatest demand established for any month during the twelve months ending with the current month as further defined herein, and (3) the standby charge based upon the difference, if any, between the customer's reserved capacity and the demand used in determining the demand charge portion of the minimum bill hereunder. The demand used in determining the demand charge portion of the minimum bill shall exclude demands established during periods which the Company has explicitly designated for delivery of economy replacement energy and in which customer has conformed to the limits specified for such energy, and shall exclude the portion of any established demand which is attributable to service provided for a coordinated scheduled outage, but in no event shall be less than the minimum billing demand specified by the price schedule to which this Rider is applicable.

Rider No. 1 to Electric Large General Service - Standby and Supplementary Service (con't)

Standby Capacity: The kW of capacity which is available to customer to serve the portion of customer's load which is supplied by a source of power other than the Company's electric system and which may be placed upon the Company's system at the discretion of the customer. Standby capacity shall be determined as the difference between the reserved capacity and the greatest of (1) the greatest load which is actually placed upon the Company's system in the current month excluding demands established during periods which the Company has explicitly designated for delivery of economy replacement energy and in which the customer has conformed to the limits specified for such energy; or (2) the load as otherwise specified for the minimum bill. The non-coincident difference shall be used where reserved capacity is determined by continuing measurements.

Reserved Capacity: The capacity which the Company is to provide for customer's use, including capacity for standby service and capacity for current delivery of power and energy. The reserved capacity for the current month shall be the greater of (1) a quantity mutually agreed upon in writing by customer and Company, or (2) the greatest load which customer has actually placed upon the Company's system during the 12 months ending with the current month, excluding loads during periods which the Company has explicitly designated for delivery of economy replacement energy in which customer has conformed to the limits specified for such energy.

Provided, however, within 90 days following the date on which customer has actually placed a load upon the Company's system which is greater than the quantity mutually agreed upon, excluding loads during periods which the Company has explicitly designated for delivery of economy replacement energy in which customer has conformed to the limits specified for such energy, Company may provide written notice to customer that the reserved capacity previously mutually agreed upon does not adequately represent customer's apparent requirements, and request that the parties enter into negotiations to specify by a new mutual agreement a revised quantity for the reserved capacity. In the event the parties do not reach a new mutual agreement within 90 days following the date of the notice, the reserved capacity for the current month shall thereafter be the greater of (1) the quantity previously mutually agreed upon by customer and Company, (2) the greatest load which customer has actually placed upon the Company's system during the 12 months ending with the current month, excluding loads during periods which the Company has explicitly designated for delivery of economy replacement energy in which customer has conformed to the limits specified for such energy, or (3) the greatest load which customer has actually placed upon the Company's system after 90 days following the date of the notice, unless subsequently modified by mutual agreement of the parties.

Company and customer may, by mutual consent, increase or decrease the reserved capacity. However, the Company shall be under no obligation to provide greater capacity without reasonable notice to permit necessary modifications to its system, and shall be under no obligation to agree to a lower specification until the customer demonstrates to the Company's satisfaction that the total load customer will place upon the Company's system is less than the currently effective reserved capacity.

Rider No. 1 to Electric Large General Service - Standby and Supplementary Service (con't)

Demand: The kW as shown by or computed from the readings of the Company's demand meter for the 15-minute period of customer's greatest use during the month, determined to the nearest kW, but not less than the minimum billing demand specified by the price schedule to which this Rider is applicable, provided that demands established during the periods which Company has explicitly designated for delivery of economy replacement energy and in which customer has conformed to the limits specified for such energy will be excluded.

Economy Replacement Energy: Company may, at its sole discretion, designate periods during which customer may take increased amounts of energy from Company as a replacement for energy which customer would normally supply from its alternate source. Company may establish limits to the rate of flow and amount of energy available to customer during any such designated period. Economy replacement energy will be billed in combination with other energy delivered to customer during the billing period under the applicable prices, with no increase in demand for billing purposes because of such economy replacement energy delivery provided customer has conformed to the limits specified.

Scheduled Outage Coordination: Company and customer may coordinate the planning and the determining of a schedule for performance of periodic maintenance of customer's facilities, such maintenance normally to be scheduled during the months of October through May. The loads placed upon the Company's system by customer during the term of the agreed schedule for maintenance of customer's facilities shall be used in determining the charges for the current period's service, but the portion of such loads attributable to the equipment scheduled for maintenance, up to but not exceeding the reserved capacity, shall not be used in determining the minimum bill for subsequent periods. Company may require the customer to provide six months or more notice of its proposed schedule for periodic maintenance. The term of the agreed schedule may thereafter be extended only with the consent of the Company in response to customer's request received prior to the scheduled end of the maintenance period.

FACILITIES COSTS: Company shall be reimbursed by the customer for costs which are incurred, or which have been previously incurred, in providing facilities which are used principally or exclusively in supplying service for any portion of the customer's requirements which are to be normally supplied from a source of power other than the Company's electric system.

A.4: Interstate Power and Light

Interstate Power and Light Company

ELECTRIC TARIFF

Filed with the I.U.B.

ORIGINAL TARIFF NO. 1

Seventh Revised Sheet No. 26
Canceling Sixth Revised Sheet No. 26

Electric Large General Service Usage

Rate Codes: 300, 307-8, 320, 327-8, 440, 447-8, 807-8

Applicable:
Large General Service Usage customers for all electric uses in one establishment adjacent to an electric distribution circuit of adequate capacity. No resale of service is permitted. Customers on this rate must have energy usage of 20,000 kWh or more in each billing month. Customers falling below required metered usage levels will be placed on the General Service Usage rate for a minimum of one year.* Service hereunder is also subject to Company's Rules and Regulations.

Character of Service:
60 Hertz alternating current single or three-phase, at secondary voltage through one meter and one point of delivery or by customer's option a higher available voltage. The Company shall provide only one transformation. Alternative voltages and/or service is available in accordance with the Rules and Regulations and Excess Facilities Charge.

Billing Provisions

Monthly Demand Charge:

Zone	All Zones		
Rate Codes	All Rate Codes		
Season	Winter	Summer	
First 200 kW	$8.21	$15.61	R
Next 800 kW	$7.49	$15.48	R
Next 9,000 kW	$6.86	$15.27	R
Next 20,000 kW	$6.68	$15.18	R
Over 30,000 kW	$4.98	$12.29	R

Energy Charge per kWh:

Zone	All Zones		IES – South & IPC Zones		
Rate Codes	307-8, 327-8, 447-8, 807-8		300, 320, 440		
Season	Winter	Summer	Winter	Summer	
On Peak	1.586¢	2.483¢	NA	NA	I
Off Peak	0.687¢	1.586¢	NA	NA	I
Non TOD Option	NA	NA	1.073¢	1.971¢	I

Summer Period:
From June 16 to September 15.

Billing Demand:
The kW demand to be used for billing purposes each month shall be the sum of the highest 15-minute demand during on-peak hours of the current month plus 50% of the amount by which the highest 15-minute demand during off-peak hours exceeds the highest on-peak demand, but not less than 75% of the highest monthly billing demand similarly determined during the previous months of June, July and August. In no month shall the monthly billing demand be less than 50 kW.

* A Customer may request an undue hardship exemption pertaining to the usage qualification standard in accordance with Section 5 of the Company's Rules and Regulations.

Date Issued: January 18, 2011 Effective Date: February 25, 2011
By: Erik C. Madsen – Director, Regulatory Affairs

Interstate Power and Light Company

ELECTRIC TARIFF

Filed with the I.U.B.

Substitute Second Revised Sheet No. 27

Canceling First Revised Sheet No. 27

ORIGINAL TARIFF NO. 1

Electric Large General Service Usage

Rate Codes: 300, 307-8, 320, 327-8, 440, 447-8, 807-8

Time of Day:
On-Peak/Off-Peak Definition: On-peak hours shall be from 7 a.m. to 8 p.m. CST (8 a.m. to 9 p.m. during daylight savings time), Monday through Friday. Off-peak hours are all other times.

Excess Facilities Charge:
Any standard facilities required to provide non standard service, in excess of that permitted under this Schedule or the Company's Rules and Regulations, shall be provided at a monthly amount equal to 1.6% of the Company's investment in such facilities.

Primary Service Discounts:
Where primary service is available and provided the Customer purchases primary service and furnishes the approved transformation and protective devices, the following discounts on demand charges will be allowed: 4.42% for transformations from the available IPL standard primary service voltage to less than 34,500 volt C
service, 7.50% for 69,000 and 34,500 volt service (Customer assumes all responsibility transforming voltage from transmission level) and 10.00% for 115 kV service and above. A Customer is not eligible for both point of T
delivery discounts and primary service discounts.

Meter not at point of delivery:
Where metering is not done at the point of delivery such as primary metering with secondary voltage delivery or secondary voltage metering with primary voltage, there will be a 2.0% decrease or increase in metered kW demand and kWh respectively before above rate schedule is applied. A Customer assumes all cost N
responsibility to configure service to primary metering and is responsible for any incremental costs IPL incurs N
above the secondary metering application. A Customer is not eligible for both point of delivery discounts and N
primary service discounts.

Power Factor:
The above rate schedule is based on a power factor of 90% or higher. Where the power factor is less than 85%, the net demand charges will be increased by 1% for each whole 1% the power factor is below 90%; likewise where the power factor is higher than 95%, the demand charges will be decreased by 1% for each whole percent point the power factor is above 90%. The power factor shall be determined by suitable recording instruments. A power factor of 100% will be used in the event the Customer is providing kilovars to the IPL system at the time the billing demand is set.

Second Nature Program:
A voluntary program, which allows customers to support generation technologies that rely on renewable energy resources. The Second Nature program affects the Energy Cost Adjustment, see Rider SECNAT.

Energy Cost Adjustment:
Billing under this schedule will include an adjustment per kWh, computed monthly to compensate for changes in the cost of fuel as described in the Energy Adjustment Clause, Rider EAC.

Tax Adjustment Clause:
This price is subject to a Tax Adjustment, see Rider TAX.

Economic Development Clause:
See Rider ECON.

Energy Efficiency Bill Credit:
See Rider EEBC.

Energy Efficiency Cost Recovery Clause:
See Rider EECR.

Date Issued: March 2, 2011

Effective Date: February 25, 2011

By: Erik C. Madsen – Director, Regulatory Affairs

Interstate Power and Light Company

ELECTRIC TARIFF

Filed with the I.U.B.

ORIGINAL TARIFF NO. 1

Third Revised Sheet No. 28
Canceling Substitute Second Revised Sheet No. 28

Electric Large General Service Usage

Rate Codes: 300, 307-8, 320, 327-8, 440, 447-8, 807-8

Regional Transmission Service Clause: N
Billing under this schedule will include an adjustment per kW, computed annually, to compensate for changes in N
the cost of transmission service as described in the Regional Transmission Service Clause, Rider RTS. N

Prompt Payment Provision:
After 20 days, add 1 1/2% on the past-due amount.

Interruptible Service Option:
See Rider INTSERV.

Interruptible Demand Transfer Service Option:
See Rider IDTS.

Day Ahead Hourly Time Of Use Service Option:
See Rider DAHP, Day Ahead Hourly Time Of Use.

Date Issued: January 18, 2011 Effective Date: February 25, 2011
By: Erik C. Madsen – Director, Regulatory Affairs

Rider SSPS - Standby and Supplementary Power Service
Rate Codes: 790/840

Availability:
Applicable to power and lighting requirements of Large General Service or Large General Service – Bulk Customers having their own generating facilities and desiring standby or supplementary power and who have entered into an Electric Service Agreement with the Company for the interconnection and operation of on-site extended parallel distributed generation systems with capacity of 100 kW or more. The Qualifying Facility is a cogeneration facility or a small power production facility under 18 CFR Part 292, Subpart B or an Alternative Energy Production facility as defined in tariff AEP. Customer's need for temporary standby power will be used for scheduled maintenance and unscheduled outage service. Supplementary power shall be used by a Customer having additional power requirements beyond that provided by their self-generation. The rates for supplementary power in this tariff apply to those customers whose supplementary power requirements are less than forty percent (40%) of the entire Customer's facility power requirements. Large General Service or Large General Service – Bulk tariff rates apply when a Customer's supplementary power requirements are in excess of 40% of customer's entire facility requirements. Contracts will be made for this service provided the Company has sufficient capacity available in production, transmission and distribution facilities to provide such service at the location where the service is requested. Not applicable for resale Customers.

Power production equipment at the Customer site shall not operate in parallel with the Company's system until the installation has been inspected by an authorized Company representative and final written approval is received from the Company to commence parallel operation.

A Customer receiving standby and/or supplementary service may terminate standby and/or supplementary power service and establish service under the applicable standard non-residential service tariff within the same time frame as would be required of a new Customer with a similar load to establish service under a Company non-residential service tariff. The term of any notice required to switch to standard tariff service will be dependent on the Company's ability to adjust its generation capability, including reserve margin, for the increased firm load due to Customer's selection of standard tariff service from the Company.

Energy provided to the Customer under this tariff is limited to energy for scheduled maintenance, unscheduled outages, and supplemental service as defined in the definitions below. Customer shall not generate and allow energy to flow onto the Company's system unless it is separately metered or otherwise permitted in accordance with the Company's Rule and Regulations.

For purposes of determining applicability of this rate schedule, the following definitions shall be used:

(1) "Firm Standby Service" means electric energy or capacity supplied by the Company to replace energy or capacity ordinarily generated by the Customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the Customer's generation. Firm Standby Service is IPL's most reliable, constant electric service; IPL would interrupt the supply of electricity to firm service Customers only as a last resort. The cost of firm service includes the reservation cost of generation, transmission and distribution of electricity plus usage charges.

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(2) "Non-firm Standby Service" means electric energy or capacity supplied by the Company to replace energy or capacity ordinarily generated by the Customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the Customer's generation. Non-firm Standby Service is the electric service that IPL provides only to the extent that it has capacity not being used to meet the needs of firm-service Customers. The cost of non-firm service includes the distribution and/or transmission reservation costs of electricity plus usage charges.

(3) "Supplementary Service" means electric energy or capacity supplied by the Company in addition to that which is normally provided by the Customer's own generation equipment.

A Customer taking service under Company's AEP or CSPP tariffs and requiring 100 kW or less of standby capacity from the Company is exempted from paying any standby charges. Standby service will be available to these Customers through its base tariff rates.

Standby Service and Supplementary Service is not available for emergency standby generation.

Service hereunder is also subject to Company's Rules and Regulations.

Service Agreement:
Customer will be required to contract for the service provided under this tariff for an initial term of not less than five years with an appropriate cancellation charge covering the cost of installation and removal of facilities if service is terminated in less than ten years, unless otherwise mutually agreed upon by the Customer and the Company.

A notice of one year may be required before the Company will allow a Customer currently receiving firm service from the Company, for a load in excess of ten thousand (10,000) kW, to begin service under this tariff unless otherwise mutually agreed upon by both the Company and the Customer. The term of any notice will be dependent on the Company's ability to adjust its generation capability, including reserve margin, for the reduced firm load due to self-generation installed by the Customer.

Character of Service:
The Company delivers 60 hertz, single or three-phase, alternating current service at transmission, primary or secondary voltage under this tariff. As available and at the Company's option, such service shall be supplied at available voltage.

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Monthly Standby Charges:

	Firm Scheduled Standby	Non-firm Scheduled Standby	
Reservation Fees: Base Demand Charge per Month per kW of Contracted Standby Capacity			
Reservation Generation Service	$0.69	$0.00	I
Reservation Transmission Service*	Rider RTS	Rider RTS	I
Reservation Distribution Service**	$4.34	$4.34	I
Scheduled Standby Usage Rates: Daily Demand Charge Per kW for each daily maximum On-peak Standby demand			
Secondary Rate	$0.37	$0.37 ***	
Primary Rate	$0.36	$0.36 ***	
Transmission Rate	$0.34	$0.34 ***	I
Non-fuel energy charges per kWh:			
On-peak Summer	$0.02483	$0.02483	I
Off-peak Summer	$0.01586	$0.01586	I
On-peak Winter	$0.01586	$0.01586	I
Off-peak Winter	$0.00687	$0.00687	I

* Terms, conditions, and charges for transmission service are subject to MISO's Open Access Transmission Tariffs. Rate subject to Rider RTS Standby rate. N

** Distribution service is required for all customers served at a non-transmission voltage level. Secondary rate is applicable for voltages under 4,160 volts, transmission rate is applicable for voltages 69,000 volts and above, and primary rate is applicable to all other voltages.

*** In the event Customer requires capacity during such times the Company has insufficient accredited capacity under its power pool agreement the Company at its option may purchase additional capacity to serve unscheduled standby service. All capacity charges and any other costs incurred by Company in obtaining such additional capacity shall be billed to Customer.

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Unscheduled Standby Usage Rates:
Unscheduled energy provided to the Customer under this tariff is limited to backup energy required during a forced outage of the Customer's self-generation. In lieu of the Scheduled Standby Usage rates above, the price for such sales shall be based on each hourly kW priced at the Midwest Independent System Operator (MISO) ALTW.ALTW node real-time LMP price plus a 10% adder for any incremental administrative and MISO-related charges, less the energy adjustment clause factor for the month. Customer is allowed to use unscheduled standby service up to 964 hours per year without incurring additional supplementary power charges. In addition, the Rider EECR, Rider TAX, and Rider EEBC shall apply.

Customer Charge:
A monthly customer charge shall also apply as follows:

Transmission	Primary Distribution	Secondary Distribution
$550	$85	$245

Definition of Peak Periods for Stand-by Service:
On-Peak: 7 AM - 8 PM CST weekdays.
Off-Peak: All other hours.

Summer Season Definition for Stand-by Service:
Summer – June 16 through September 15.

Minimum Charge for Stand-by Service:
The minimum charge for any month's service shall be the reservation fee for the applicable billing demand plus the customer charge.

Determination of Demand for Stand-by Service:
For purposes of applying the Reservation Fee, the demand will be the quantity specified in the Customer's Electric Service Agreement as the maximum amount of Standby Service the Company is obligated to supply. This quantity may be different between the summer and winter seasons. For applying the Usage Rate, when the Customer's generation is less than the minimum normal operating level as specified in the Agreement, the standby demand shall be the smaller of the following two amounts: (1) the amount of Standby capacity contracted for by the Customer minus the actual demand supplied by the Customer's own generating facilities, but not less than zero, or (2) the amount of actual capacity supplied by the Company. This amount of standby contract demand will be determined independent of and will have no effect on the standby usage demand of the Customer applied under the usage rates of the tariff. The actual capacity supplied shall be adjusted for power factor as described below.

Power Factor for Stand-by Service:
A reactive demand charge of $1.41 per kVAr will apply for the portion of the maximum kVAr registered during the month in excess of 20% of the maximum kW registered during the month.

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Contract Standby Demand:
The level of Customer's generation requiring Standby Service as specified in the Agreement. This contract standby demand will not be less than the maximum load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generation equipment. Actual demand in excess of the firm contract demand shall become the new contract demand level for the next 12 months.

Monthly Supplementary Service Charges:

a) Secondary, Primary, Sub-transmission, and non-Bulk Usage Transmission Voltage levels.

Demand Charges:
Charge per kW of Billing Demand

Demand	Summer	Winter	
First 1,000 kW	$15.48	$7.49	R
Next 9,000 kW	$15.27	$6.86	R
Next 20,000 kW	$15.18	$6.68	R
Over 30,000 kW	$12.29	$4.98	R

Energy Charges (exclusive of EAC and EECR Adjustments):
Charge per kWh

	Summer	Winter	
On-peak	$0.02483	$0.01586	I
Off-peak	$0.01586	$0.00687	I

b) Bulk Usage Transmission Voltage Level where IPL provides 161 kVA service that Customer transforms to 69 kVA (FROZEN-limited to existing Bulk Usage Customers).
Demand Charges:

Billing Demand	Per kW	
All kW	$8.45	R

Energy Charges (exclusive of EAC and EECR Adjustments):

Energy Charge	Per kWh	
All kWh	$0.00364	I

Summer Period for Supplementary Service:
From June 16 to September 15.

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Billing Demand for Supplementary Service:
The kW demand to be used for billing purposes for non-transmission and non-Bulk usage transmission voltage service each month shall be the sum of the highest 15-minute supplementary demand during on-peak hours of the current month plus 50% of the amount by which the highest 15-minute supplementary demand during off-peak hours exceeds the highest on-peak demand, but not less than 75% of the highest monthly billing demand similarly determined during the previous months of June, July and August. Billing demand for Bulk usage transmission voltage service shall be the largest metered demand in the twelve months ending with the current billing month but not less than 25,000 kW.

Time of Day Defined for Supplementary Service:
On-Peak/Off-Peak Definition: On-peak hours shall be from 7 a.m. to 8 p.m. CST (8 a.m. to 9 p.m. during daylight savings time), Monday through Friday. Off-peak hours are all other times.

Primary Voltage Service Discounts for Non-Bulk Usage Supplementary Service:
Where primary service is available and provided the Customer purchases primary service and furnishes the approved transformation and protective devices, the following discounts on demand charges will be allowed: 4.42% for transformations from the available IPL standard primary service C
voltage to less than 34,500 volt service, 7.50% for 69,000 and 34,500 volt service (Customer C
assumes all responsibility transforming voltage from transmission level) and 10.00% for 115 kV service and above.

Power Factor for Supplementary Service:
The supplementary demand charges are based on a power factor of 90% or higher. Where the power factor is less than 85%, the net demand charges will be increased by 1% for each whole 1% the power factor is below 90%; likewise where the power factor is higher than 95%, the demand charges will be decreased by 1% for each whole percent point the power factor is above 90%. The power factor shall be determined by suitable recording instruments. A power factor of 100% will be used in the event the customer is providing kilovars to the IPL system at the time the billing demand is set.

Riders and adjustment clauses applicable to Standby and Supplementary Services:

Energy Adjustment Clause (applicable only for Firm Standby and Supplementary Services):
Billing under Standby Service for both unscheduled and scheduled kWh shall include an adjustment, computed monthly, to compensate for the cost of fuel and purchased power as described in the Energy Adjustment Clause Rider EAC. All incremental unscheduled standby usage revenues in excess of the revenues that would otherwise be collected under the current month energy cost adjustment factor from Customers on this rider shall also be treated as a 100% Iowa deduction from the fuel adjustment calculations. Billing under Supplementary Service will include an adjustment per kWh, computed monthly to compensate for the cost of fuel and purchased power as described in the Energy Adjustment Clause, Rider EAC.

Energy Efficiency Cost Recovery Clause:
See Rider EECR.