Interstate Power and Light
(Subsidiary to Alliant Energy)
Standby Rate Considerations

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Acronyms

CEAC	U.S. DOE Clean Energy Application Center (now known as the U.S. DOE CHP TAP)
CHP	Combined Heat and Power
CHP TAP	U.S. DOE CHP Technical Assistance Partnership (previously the U.S. DOE CEAC)
DG	Distributed Generation
ELPC	Environmental Law and Policy Center
FOR	Forced Outage Rate
IEC	Iowa Environmental Council
IPL	Interstate Power and Light
ITC	Independent Transmission Company, owner of Alliant's former transmission assets
IUB	Iowa Utilities Board
LMP	Location Marginal Pricing
MISO	Midcontinent Independent System Operator
OCA	Iowa Office of Consumer Advocate
PURPA	Public Utility Regulatory Policies Act of 1978
Rider SSPS	IPL's Standby and Supplemental Rate

Executive Summary

It is the goal of this paper to provide Iowa policy stakeholders (including the Iowa Environmental Council (IEC), the Iowa Utilities Board (IUB) and Interstate Power and Light (IPL) – the Iowa subsidiary of Alliant Energy) with an analysis of the economic impacts on CHP systems created by IPL's current standby rate. Additionally, this paper offers a framework for more beneficial standby rates that, while allowing for utility cost recovery, also incorporates successful approaches for eliminating barriers to DG and combined heat and power (CHP). Similar to the recent experience with MidAmerican Energy in 2013, this research is intended as the beginning of a collaborative process with the intent to reduce the financial barriers currently present in IPL's standby rates.

In a previous study completed January 2012, the U.S. DOE Midwest Clean Energy Application Center (Midwest CEAC, now the Midwest CHP TAP) found that IPL's current standby rates financially burden otherwise economically viable distributed generation (DG), including combined heat and power (CHP) projects. [1] Combining the principles of cost of service rate methodology [2] with various rate analysis metrics[3] in addition to metrics developed by the Midwest CHP TAP, this study further determined that the structure underpinning IPL's standby rates and the method in which IPL allocates and recovers utility costs is inconsistent with how standby customers incur costs. This inconsistent cost recovery contributes to the financial burdens faced by standby customers. The following list contains the attributes within IPL's standby rate most responsible for claims of inconsistent cost allocation:

- Standby customers pay a greater amount to reserve transmission capacity than large general service customers pay to actually use that transmission capacity.
- Transmission costs are assessed to IPL by transmission owner, ITC Midwest, on a coincident peak basis; however, IPL recovers transmission costs using an excess and average methodology whereby standby customers are charged for transmission service even if they do not use service during peak periods.
- A standby customer with a small forced outage rate will pay the same reservation charge as another customer with a much greater outage rate even though the two customers exert different costs onto the grid.
- All unscheduled standby usage (forced outage) is priced using real time locational marginal pricing even if the standby customer paid to reserve generation service and IPL has sufficient generation capabilities.
- Both firm and interruptible standby customers pay the same for distribution and transmission service even though interruptible service can be terminated due to capacity constraints.

[1] US DOE Midwest Clean Energy Application Center, "Iowa On-Site Generation Tariff Barrier Overview," 2012. Available at, http://www.iaenvironment.org/documents/energy/TariffBarrierOverview.pdf

[2] As constructed by James C. Bonbright et al in the second edition of his seminal work "Principles of Public Utility Rates."

[3] As constructed by the U.S. EPA CHP Partnership, the National Regulatory research Institute (NRRI), the American Council for Energy Efficient Economy (ACEEE), ICF International, and the State and Local Energy Efficiency Action Network (SEEAction)

The Midwest CHP TAP analyzed model rates of other utilities in other states to provide guidance on best practices to restructure standby rates in a manner that can more accurately allocate and recover costs benefitting both the utility and standby customers. The standby rates of Pacific Power in Oregon and Detroit Edison in Michigan were used as the primary models with several other utilities and rate studies serving as guidance in these recommendations.

This paper concludes that the financial disincentives that exist for CHP and DG caused by the existing IPL standby rates, can be removed by revising IPL standby rates to better allocate costs in accordance with a cost of service methodology, and improving its structure with provisions that are more transparent, flexible, and promote economically efficient consumption.

Transparent rates provide customers clear signals on the cost of each aspect of electric service to allow customers to operate in a manner that lessens their burden to the utility. Aspects of transparency entail:

- The separation of capacity costs to best reflect the drivers of cost for each component, i.e. dedicated distribution, shared distribution, transmission, and generation capacity;
- A differentiated demand charge reflecting the costs associated with on-peak and off-peak periods for transmission and distribution service;
- Unbundling rates to the maximum extent feasible; and
- Clear, easily understood rate mechanics.

Examples of successful transparent rate design include:

- Pacific Power Partial Service Rate 47 (Oregon) separates the distribution charge into three categories (Basic, Facility, On-Peak) to most accurately capture the drivers of each component. The facilities charge covers the cost of local delivery facilities that must be dedicated to serve a specific customer while the on-peak demand charge covers the costs associated with shared distribution facilities. The basic charge is akin to a customer charge – a fixed monthly charge delineated by voltage class.
- Detroit Edison Rider 3: Parallel Operation and Standby Service (Michigan) uses daily, as-used, on-peak demand charge to recover utility costs; these charges are differentiated depending on the nature of the service (scheduled or unscheduled).
- MidAmerican Energy Rider SPS (Iowa) divides the reservation charge into four categories corresponding to generation, transmission, distribution and substation cost causation. A customer's forced outage rate is used to calculate the generation and transmission components.

Flexible rates are those which allow the customer to avoid charges when not using service. Further aspects of flexibility include:

- Rates that provide the ability to self-supply reserves or remove load during DG outages;
- Rates that incorporate load diversity and outage probability;
- Rates that allow customers to minimize charges by operating in a manner beneficial for the utility; and

- Rates that allow, if available, the ability to purchase power from real-time markets.

Examples of successful flexible rate design include:

- Pacific Power (Oregon) allows customers to self-supply reserve load in order to avoid utility reserve charge.
- Pacific Gas and Electric Schedule S (California) calculates reservation capacity using the outage diversity of a customer's generating unit.
- American Electric Power (Ohio) allows a standby customer to choose their outage level which corresponds to the monthly reservation charge.
- Detroit Edison (Michigan) allows standby customers the choice to purchase all standby capacity from the real time market.

A fundamental purpose of a cost of service methodology rate structure is to *promote economically efficient consumption* in ways that benefit both the utility and the customer. Rate mechanisms that help achieve economically efficient consumption include:

- Sending clear price signals that charge a premium for unscheduled outage demand that coincides with utility peak, and minimizing charges for scheduled outage demand during periods of excess utility capacity;
- Removing or reducing ratchets in order to allow customers to ration themselves efficiently every month; and
- Recovering costs in a manner that penalizes customers who use the grid inefficiently while allowing customer to avoid charges when not taking service.

Examples of successful standby rates that promote efficient consumption include:

- NSTAR Rate T-2 (New York), Portland General Electric Rate 75 (Oregon), and MidAmerican's Rider SPS (Iowa) have no demand ratchets.
- Hawaiian Electric Company Rate SS (Hawaii) charges standby customers a fairly high ($0.156/kWh) energy charge during both scheduled and unscheduled DG outages. This provides the customer a strong and direct incentive to ensure that their generator is well maintained.[4]
- Southern California Edison rate TOU-8-RTP-S (California) delineates the price for standby energy in hourly allotments corresponding to ambient air temperature, voltage taken, and day of week. This gives standby customers a detailed knowledge of how utility costs are incurred and how and when to operate to avoid high costs.

Standby rates are necessary for a utility to recover the costs incurred to serve customers with on-site generation, but they should be created in a way that justly and without undue discrimination allocates only those costs incurred by such customers. This paper provides examples from multiple utilities of rate mechanisms that fairly recover incurred costs while being transparent and flexible, and incentivizing efficient consumption. It is not, however, the intention of this paper to propose specific rates, but to provide examples of different rate mechanisms that more evenly allocate costs incurred while

[4] Hawaiian Electric Company, Schedule SS: Standby Service, Sheet No. 69, Effective May 15, 2008.

promoting economically efficient consumption. Unlike specific rates, these rate mechanisms are broad enough to be applicable in vastly different utility situations.

This paper also explores the extent to which IPL's current standby cost allocation achieves cost-based rates for CHP customers. Creating an analytic framework that uses rate theory and current federal legislation to guide utility regulation, this paper shows that IPL's standby rate structure may unfairly allocate costs which in turn can impede important rate functions and worsen the financial viability of combined heat and power projects. Those mechanisms in IPL's rate structure that create inconsistent cost recovery include IPL's methodology for transmission cost recovery from standby customers, the year-long supplemental demand ratchet, the 964 hour limit to unscheduled standby service, and the lack of available market options.

Findings and Examples of Successful Standby Rate Structures:

Unlike businesses operating under market conditions in which innovation is financially rewarded, regulated utilities have little financial incentive to create new, more innovative or flexible rates. This push for reform and innovation falls most strongly on regulators and advocates. The following table provides a summary of the analysis of IPL's current standby rates and compares these rates to successful approaches of standby rate structures in other utilities.

Table 1: Summary of IPL Standby Rate Barriers and Successful Approaches to Standby Rate Structures by Other Utilities

Principle	Identified Factor	Analyzing Interstate Power and Light's Standby Rates	Successful Approaches to Standby Rate Structures
Transparency	Transmission Cost Allocation	IPL allocates transmission costs for standby customers using an excess and average methodology even though transmission owner, ITC Midwest, allocates costs to IPL using a coincident peak methodology. Standby customers are assessed transmission charges every month even if they do not use the transmission grid during peak periods.	Pacific Power in Oregon assesses transmission costs using on-peak methodology. This more accurately reflects the costs of providing transmission service. MidAmerican Energy in Iowa calculates the transmission reservation charge using a customer's forced outage.
	Unbundling Reservation Rate	IPL unbundles their reservation rate into generation, distribution and transmission components.	Portland General Electric further unbundles their distribution charge between shared and dedicated distribution infrastructure. A customer's FOR is then applied to the shared distribution component. NSTAR separates distribution costs between summer and winter peaks reflecting difference in cost incurrence.
Flexibility	Load Shedding Provisions	IPL allows standby contract capacity to be set by the customer.	Pacific Power employs mutually agreed upon standby contract capacity including opportunities for standby customers to self-supply reserves or install a load limiting device.
	Daily As-Used Demand Charge	IPL provides daily as-used demand charges for scheduled outages only.	Orange and Rockland recover all standby distribution charges through a daily as-used demand charge.
Promoting Efficient Consumption	Use of Forced Outage Rate to Calculate Reservation Charge	IPL does not incorporate a standby customer's forced outage rate in the calculation of the reservation charge.	Southern California Edison incorporates outage diversity into the calculation of a standby customer's reservation charge. MidAmerican Energy calculates the generation and transmission component using a customer's FOR. AEP in Ohio allows a standby customer to choose their outage level reservation rate.
	Demand Ratchets	IPL employs a 75% peak summer demand ratchet.	NSTAR (MA), Portland General Electric (OR) and MidAmerican (IA) employ no demand ratchets in their supplemental tariff.

1. Introduction

In the fall of 2010 the U.S. DOE Midwest Clean Energy Application Center (Midwest CEAC), now the U.S. DOE Midwest CHP Technical Assistance Partnership (Midwest CHP TAP), was contacted by the Iowa Environmental Council (IEC) and the Environmental Law and Policy Center (ELPC) to study the electric rates in Iowa in order to assess their financial effects on distributed generation (DG), specifically combined heat and power (CHP) systems. This study was the result of two separate settlement agreements that the IEC and ELPC filed with MidAmerican Energy and Interstate Power and Light (IPL) in order to examine possible barriers to CHP. The Midwest CEAC published their final paper[5] in 2012 and found that the standby rates of both MidAmerican and IPL acted as a barrier to the financial viability of CHP and other DG projects.

In 2013, MidAmerican Energy updated and consolidated their three previous tariff books in order to reflect their most recent cost of service study. The Midwest CEAC worked with the IEC and ELPC to provide technical assistance to MidAmerican as the utility designed its future standby rates. The standby rate that MidAmerican filed with the Iowa Utilities Board (IUB) in Docket RPU-2013-0004 was the result of this collaborative process. Through this collaborative process, MidAmerican reformed its standby rate to more precisely and consistently recover utility costs incurred by standby customers.

This paper analyzes IPL's standby rate using public utility rate theory in order to assess how some standby rates can create economic barriers to otherwise viable CHP systems. Standby rates designed to recover cost of service are largely unique to each utility's characteristics, however there are overarching principles that are universally applicable. Transparency, flexibility, and the promotion of economically efficient consumption are guiding principles that help to more consistently and beneficially allocate and recover costs, specifically those of distributed generation and combined heat and power customers. These principles allow a utility to recover their costs in a manner that specifically targets the loads that drive investment and cost. Using a sample of successful approaches to standby rates from across the U.S., this paper then provides considerations for possible tariff modifications. This analysis assesses IPL's rates and provides potential modifications using three rate characteristics each corresponding to and promoting an important rate function. The three categories include transparency, flexibility and the promotion of efficient consumption. These points concisely divide and evaluate standby rates in order to better understand how IPL's rates create barriers to CHP.

This paper provides considerations for standby rate reform that would reduce the economic burden to CHP and DG systems currently created by IPL's standby rate.

[5] US DOE Midwest Clean Energy Application Center, "Iowa On-Site Generation Tariff Barrier Overview," 2012.

2. Factors of Cost-Based Rates

The State of Iowa uses the cost of service standard to regulate rates that electric utilities may charge their customers.[6] Regulators often use the *cost of service* standard to calculate "fair and reasonable" rates because its methodology directly ties consumers to the cost of producing those goods and services consumed (in this case, electricity).[7] Furthermore, the Public Utility Regulatory Policies Act (PURPA) of 1978 mandates that electric rates shall be designed, to the maximum extent practicable, to reflect the cost of service.[8] A cost based approach, like the cost of service standard, achieves at least three important functions of public utility rate making: *consumer rationing, capital attraction*, and *compensatory income transfer*.[9]

1) Consumer Rationing – Under the principle of *consumer rationing*, consumers are free to take service (whatever kinds in whatever amounts), "as long as they are ready to indemnify the producers…for the costs of rendition," thereby rationing themselves to only what is needed and no more.
2) Capital Attraction – To ensure service now and in the future, *capital attraction* guarantees the service provider a funding source for both operating and capital expenses that are necessary to sustain grid infrastructure.
3) Compensatory Income Transfer – Lastly, the *compensatory income transfer* function requires those seeking a service to account for the use of the service through a monetary expenditure.

Achieving these three functions helps the cost of service standard recreate competitive market conditions in a situation devoid of competing market forces (i.e. electric utility monopoly in a regulated state or electric distribution utility in a deregulated state). Economists and rate theorists typically use competitive markets as guidelines for the regulation of monopolistic prices. The cost of service methodology is the commonly applied regulatory approach to simulate competitive market conditions.

2.1 General Rate Attributes

No matter the method in which rates are regulated (i.e. cost of service, value of service, performance standard, etc.), general rate function can be classified into three overarching attributes: revenue, cost, and practicality.[10]

1) *Revenue* related concerns include achieving the total revenue requirement predictably and stably through rates that are themselves stable and predictable.

[6] Iowa State Code Chapter 476
[7] David Moskovitz, *Profits and Progress Through Distributed Resources*, (Gardiner, ME: Regulatory Assistance Project, 2000), 3.
[8] *Public Utility Regulatory Policies*, 16 U.S.C. § 2625, (2012).
[9] James C. Bonbright, Albert L. Danielsen, and, David R. Kamerschen, *Principles of Public Utility Rates* (Arlington: Public Utilities Reports, 1988), 111.
[10] Bonbright et al, 383.

2) *Cost* related concerns include promoting economically efficient consumption through portioning costs fairly among customers and avoiding discriminatory rates.
3) *Practical* concerns include attributes of payment collection, rate simplicity, and ease of understanding.

These attribute categories are important for shaping the context of the IPL standby rate analysis. Rates that fail to clearly display these attributes may also fail at achieving the larger rate functions mentioned above, which, in turn, could allow for claims of unfair or non-cost based rates. The cost attribute function is important in this discussion as it specifically addresses issues of fair cost allocation. Rates that do not fairly allocate costs might impede the consumer rationing function which in turn hinders a consumer's ability to ration consumption based on accurate and market-simulated pricing. When costs are not fairly recovered or when rates are not cost-based, utilities could manipulate prices in order to increase consumption and thus revenue. The role of a cost of service methodology is to bind customers and customer classes to the specific costs they impose on the utility.

2.2 Functions of Cost-Based Rates

Cost-based rate structures must achieve both the rate attributes and rate functions listed previously while also allowing the utility to obtain its total revenue requirements. A cost of service study is necessary in order to determine the various costs imposed on the utility by each customer class. The central questions often facing a cost of service study are:

1) What specific costs are included?
2) How are these costs recovered from customers based on their consumption patterns?

Utility customers are typically grouped into rate classes and charged based on how they consume electric service. The most common classes correspond to residential, commercial and industrial classifications; however other classifications using similar voltage level and/or load level are also used in creating customer classes. The use of aggregate classes allows the utility to create rates that more accurately allocate costs, yet challenges arise when determining the level at which customer classes are responsible for utility costs.

Rate structures should be created in a manner that avoids arbitrariness, capriciousness and undue discrimination while covering the full costs each customer and customer class imposes on the grid. No rate class should subsidize the costs incurred by other classes nor should customers pay for costs that they themselves do not incur. In order to analyze IPL's standby rates and to assess the effectiveness of model tariffs, three criteria are used to evaluate the soundness and desirability of cost based electric rates structures:

> **Criterion 1 – Transparency**: Rates should be easily understood with rate mechanics and price levels that are stable and predictable. Transparent rates should provide price signals that clearly reflect the many cost drivers associated with electric service allowing customers to understand when, how and where utility costs are incurred. Having clearly delineated price signals and rate

mechanics helps promote more accurate consumer rationing and addresses the revenue and practicality rate attributes.

- **Criterion 2 – Flexibility**: Rates should distribute the burden of meeting total revenue requirements fairly and without arbitrariness, capriciousness, and inequalities among the beneficiaries of service in order to avoid undue discrimination. Flexible rates should allow customers to avoid charges when not taking service and also provide standby customers with options for taking alternative service. Flexibility in electric rates helps promote consumer rationing and addresses the cost and practicality rate attributes.

- **Criterion 3 – Economically Efficient Consumption:** Rates should be designed to discourage the wasteful use of utility services while promoting all that is economically justified in view of the relationship between the private and social costs incurred and benefits received. Economically efficient rates incentivize customers to take service when service is least expensive. This rate criterion helps promote more accurate consumer rationing and addresses the cost and revenue rate attributes.

In addition to these criteria, further guidance on ratemaking can be found in Federal Regulation, specifically those created by the Public Utility Regulation Policies Act. According to U.S. Code:

> The costs of providing service to each class of electric consumers shall…to the maximum extent practicable – permit identification of differences in cost-incurrence, for each such class of electric consumers, *attributable to daily and seasonal time of use* service and permit identification of differences in cost-incurrence *attributable to differences in customer demand, and energy components of cost*.[11]

These three criteria, as well as PURPA regulations and the cost attributes and functions previously mentioned create a framework to analyze both model standby rates and IPL's current standby rates and their respective cost recovery mechanisms.

[11] *Public Utility Regulatory Policies*, 16 U.S.C. § 2625, (2012).

3. Analyzing Interstate Power and Light's (Subsidiary to Alliant Energy) Standby Rates

3.1 IPL Standby Rate Service Offerings

Interstate Power and Light ("company") offers a standby service rider (SSPS), rate code 790/840, in their current tariff book issued 2011. Rider SSPS is available to any Large General Service or Large General Service – Bulk Power customers having their own generation equipment that requires at least 100kW of standby capacity. Rider SPSS is divided into three service offerings:

1. Firm Scheduled Standby Service
2. Non-firm Scheduled Standby Service
3. Monthly Supplementary Service Charges

3.2 Description of IPL Standby Charges

Scheduled standby service under rider SPSS includes four charges:

1. Reservation Fees - The reservation charge allows the distributed generation customer to rely on IPL during a scheduled or unscheduled outage of an onsite generation unit. A customer's standby contract capacity, to which the reservation charges are applied, is mutually agreed upon by customer and company and may differ between seasons. IPL breaks down its reservation charges intro three components, that for generation, transmission and distribution service. The only monetary difference in the reservation charge between firm and non-firm service is the $0.69 per kW to reserve generation capacity; if a customer opts for non-firm service they are able to forgo this charge. The distribution reservation service charge is $4.34 per kW. After Alliant Energy sold their transmission assets to the independent transmission operator, ITC Midwest, the transmission reservation service charge is issued and recovered through Rider RTS; in 2013 the cost for the transmission component under rider SSPS was $7.09 per kW.

2. Scheduled Standby Usage Rates - The scheduled standby usage rates are divided by voltage classification and are issued on an on-peak kW, per day charge. For customers with a contract capacity less than 10,000 kW scheduled maintenance on the generating unit must occur during the months of April, May, October or November. Customers with a contract capacity greater than 10,000 kW must provide an annual projection of scheduled maintenance to the company. The amount of advanced notice that the customer must provide is a function of the expected duration of the maintenance outage.

3. Unscheduled Standby Usage Rates - Unscheduled standby rates are priced at the Midcontinent Independent System Operator's (MISO) ALTW.ALTW node real time location marginal price

(LMP) plus a 10% adder for any utility administrative charges.[12] Standby customers are allowed to use up to 964 hours of unscheduled standby service without incurring any additional costs.

4. Customer Charge by Voltage Class - The customer charge for standby service is a monthly charge divided by voltage class.

Table 2: IPL Rider SSPS

Interstate Power and Light Rider SSPS - Standby and Supplemental Power Service		
	Firm Service	Interruptible Service
	Customer Charge	
Secondary Voltage	$245.00	$245.00
Primary Voltage	$85.00	$85.00
Transmission Voltage	$550.00	$550.00
	Reservation Rate	
Generation	$0.69	$0.00
Distribution	$7.09	$7.09
Transmission	$4.34	$4.34
Total	$12.12	$11.43
	Scheduled Standby Demand ($/kW) Daily, On-peak kW	
Secondary Voltage	$0.37	$0.37
Primary Voltage	$0.36	$0.36
Transmission Voltage	$0.34	$0.34
	Scheduled Standby Energy ($/kWh)	
On-Peak Summer	$0.02483	$0.02483
Off-Peak Summer	$0.01586	$0.01586
On-Peak Winter	$0.01586	$0.01586
Off-Peak Winter	$0.00687	$0.00687
Unscheduled Standby Usage Rates		
All unscheduled standby usage is priced using MISO's ALTW.ALTW real time locational marginal price		

3.3 Assessing IPL's Standby Rates

Interstate Power and Light's standby rate has previously been considered a significant barrier to the financial viability of CHP systems and other DG projects in Iowa.[13] As currently constructed, rider SPSS inconsistently allocates costs between standby customers in a manner that financially burdens these systems unfairly. Inconsistent cost allocation refers to instances where a standby customer is billed for service in a manner not reflected in how that service was procured by IPL. The most prominent examples of inconsistency are found in IPL's transmission cost recovery methodology, the general

[12] ALTW.ALTW is one of MISO's pricing nodes.
[13] US DOE Midwest Clean Energy Application Center, "Iowa On-Site Generation Tariff Barrier Overview," 2012.

reservation charge and the pricing of unscheduled standby service. Removing this financial burden to DG and CHP, would allow IPL's standby rates to promote efficient consumption and consumer flexibility.

3.3.1 Transmission Cost Allocation

IPL's current standby rider does not provide necessary price signals representative of how the utility incurs cost to provide service to standby customers. This practice does not promote economically efficient consumption and optimal consumer rationing. The most prominent example driving this claim is found in the transmission reservation charge. At $7.09 per kW, standby customers pay a greater amount to reserve transmission capacity than large general service customers pay to actually use that transmission capacity.[14] This means that even when standby customers *do not* go offline they pay a greater amount for transmission service than customers who use said service daily. Since standby customers pay for transmission (and distribution) service regardless of its use, there are no incentives in place to limit standby service to periods when such service is less expensive for the utility. This in turn promotes inefficient consumption.

Furthermore, IPL's current methodology of allocating transmission costs to standby customers is inconsistent with how those costs are now incurred. After Alliant Energy sold off its transmission assets to ITC Midwest, IPL incurs transmission costs based on how ITC Midwest bills IPL for its usage of that infrastructure. ITC Midwest bills transmission usage on a coincident peak basis whereas IPL distributes that cost using an excess and average methodology.[15] IPL's approach spreads the transmission costs not based on a customer class's share of the coincident peak but on their maximum and average loads regardless of when, or even if those loads use the transmission grid. The monthly bills IPL receives from ITC Midwest charge only for demand placed on the transmission network during peak periods; however, IPL recovers standby transmission costs using a monthly reservation charge based on a customer's contract capacity even if that customer never uses standby service and, by extension, the transmission grid. From a standby customer's point of view, IPL incurs the same transmission costs even when that customer does not require transmission service during that month. IPL incurs transmission costs when their customers use the transmission grid during peak periods. Economically efficient rates should reflect this by incentivizing standby usage in a manner that reduces transmission payments by both the utility and the customer.

3.3.2 General Reservation Cost Allocation

Additionally, because rider SSPS does not incorporate a customer's forced outage rate in the calculation of the reservation charge (including the distribution and transmission components) customers with widely differing outage rates may be charged the same for reservation service, thus leading to charges of inconsistent cost allocation. While the structure of the standby usage rate incentivize off-peak and scheduled usage, these charges only makes up a fraction of a standby customer's yearly bill. In order to consistently allocate costs between standby customers, the aggregate yearly costs paid by the standby customer should reflect the costs each customer imposes on the utility. A standby customer with a

[14] In 2013 Large General Service customers paid $6.68 per kW for transmission service.
[15] Iowa Utility Board, Final Decision and Order Docket RPU-2009-0002, page 96.

small outage rate will pay the same reservation charge as another customer with a much greater outage rate percentage even though the two customers exert different costs onto the grid. If, for example, a standby customer ensures that their CHP unit will not go down during a peak period or that if it does there will be some mechanism to drop the requisite load, that customer should not bear the burden of paying for the same level of transmission, distribution and generation infrastructure. As constructed, rider SSPS does not incentivize standby customers to minimize IPL's costs nor does it significantly penalize DG customers that frequently go offline during peak periods.

This point also extends to non-firm standby customers to whom IPL may suspend electric service if the necessary capacity is not available. Currently, firm and non-firm standby customers pay for the same transmission and distribution reservation charges even though serving interruptible standby customers costs less for the utility. If IPL is able to interrupt a standby customer due to transmission or distribution constraints, those services should be discounted in comparison to firm service. To this end, it would be useful to divide distribution reservation charge into shared and dedicated categories in order to best reflect the cost incurred to provide both services.

3.3.3 Unscheduled Outage Pricing

Finally, the method in which IPL recovers unscheduled standby costs might allow IPL to overcharge standby customers for that service. According to rider SSPS all unscheduled standby energy and demand is priced using MISO's real-time LMP price at the ALTW node even though IPL might not purchase this capacity on the market. Because generation and transmission costs are included in both the reservation charge and the LMP price, this methodology of recovering standby costs could lead to double charging for the same service. Instead, IPL could offer a buy-through rate in which a standby customer needs only reserve distribution service but would pay the full LMP price when taking standby service. Another approach would have unscheduled standby priced at LMP only when IPL is capacity constrained and must purchase additional capacity from the market in order to supply the customer.

4. Standby Rate Practices of Other Utilities

While every utility is different in geography, customer makeup, rate structure and other characteristics, the cost of service standard and the necessity of cost recovery are the most common rate principles guiding utilities. Regulated utilities have little financial incentive to create new, more innovative, and/or flexible rates. Push for reform and innovation typically falls most strongly on regulators and advocates. Rate structures of regulated utilities in other states can provide useful information and guidance to regulators and advocates in Iowa who are addressing similar issues.

Below are descriptions of two utility standby rates, that of Pacific Power in the State of Washington and Detroit Edison in the State of Michigan. These utilities have standby rates that promote transparency, and allow flexibility for the avoidance of costs when service is not required, and encourage efficient consumption.

4.1. Pacific Power

The first example is from Pacific Power's large general service, partial requirements Schedule 47. Rates charged by Pacific Power to standby customers are shown in Table 3:

	Delivery Voltage		
Distribution Charge	**Secondary**	**Primary**	**Transmission**
Basic Charge			
Facility Capacity ≤ 4,000 kW, per month	$340.00	$360.00	$580.00
Facility Capacity > 4,000 kW, per month	$630.00	$640.00	$1,070.00
Facilities Charge			
≤ 4,000 kW, per kW Facility Capacity	$1.35	$0.75	$0.80
> 4,000 kW, per kW Facility Capacity	$1.25	$0.70	$0.80
On-Peak Demand Charge, per kW	$2.58	$2.81	$2.54
Reactive Power Charges			
Per kvar	$0.65	$0.60	$0.55
Per kVarh	$0.0008	$0.0008	$0.0008
Reserves Charges			
Spinning Reserves			
Per kW of Facility Capacity	$0.27	$0.27	$0.27
Spinning Reserves (with Company approved Self-Supply Agreement)			
Per kW of Spinning Reserves Level	($0.27)	($0.27)	($0.27)
Supplemental Reserves			
Per kW of Facility Capacity	$0.27	$0.27	$0.27
Supplemental Reserves (with Company-approved Load Reduction Plan or Self-Supply Agreement)			
Per kW of Supplemental Reserves Level	($0.27)	($0.27)	($0.27)
Transmission & Ancillary Services Charge			
Per kW of On-Peak Demand	$0.83	$0.97	$1.43

Table 3: Pacific Power Scheduled 47

4.1.1 Transparency

The most noticeable aspect of this standby rate is its level of transparency in allocating different costs. The rate breaks down both the distribution charge and the reserves charge to most accurately capture the drivers of each component. The facilities charge covers the cost of local distribution facilities that must be dedicated to serve a specific customer while the on-peak demand charge covers the costs associated with shared distribution facilities. The facility capacity (kW), used to calculate the facilities charge, employs a rolling ratchet averaging the two greatest non-zero monthly demands established during the previous twelve months. This ratchet demand can never be lower than a customer's baseline demand but can also include the increased demand from an outage of a customer's generator.[16] Both the spinning and supplemental reserves use the facility capacity in monthly calculations as well.

4.1.2 Flexibility

The on-peak demand charge employs no ratchet, instead calculating monthly charges using each month's on-peak demand figures. The transmission and ancillary services charge also uses the monthly on-peak demand in its calculation. Both the on-peak demand charge and the facilities charge include in their calculations any increased demand from an unplanned outage, if such an outage occurs. A unique feature of this standby rate schedule is that all service – both that needed to serve a customer during DG outages (standby) and that needed to serve demand in excess of on-site generation (supplemental) – is taken under one rate.

Option of Taking Economic Replacement Power

Pacific Power offers customers with on-site generation the option of taking economic replacement power. This power is available from the utility at designated times when the cost of utility power is below that of a customer's own generation unit. Though this is part of Pacific Power's bundle of standby options it is altogether separate in function and structure than standby service. Economic replacement power benefits both the utility and the DG customer and should be considered as an available option to standby customers; however, since it is not standby service, economic replacement power does not inform these recommendations.

Avoid Reserves Charges

Pacific Power allows customers to avoid reserves charges through self-supplying or load reduction methods. This benefits the utility because it can call on a customer-generator to supply reserves when the utility needs them instead of maintaining or purchasing this additional capacity. The result is that the customer avoids greater charges on their monthly bill while helping to maintain grid stability.

4.1.3 Efficient Consumption

The generation supply rate for both supplemental capacity and scheduled maintenance service comes from the same generation supply tariff and can either be a market-based rate or a cost-based rate depending on the customer's choice. Under this tariff, a customer purchases power

[16] The baseline demand is the amount of demand supplied by the utility during the regular operation of a customer's generation unit.

for unscheduled outages directly from the real time market with an adder to cover both the risk when the real time index price is below the real time price and for any additional losses. [17]

During a customer's first three months on this rate the facility capacity equals the baseline demand level. This allows the customer generator time to work out the kinks in their generation unit and also to better understand their new rate structure. Additionally, the customer can avoid an amount of spinning and supplemental reserves charges through either a self-supply agreement or a load reduction agreement. In order to self-supply reserves, a customer must generate at least 15MW and dedicate 3.5% of generating capacity towards spinning or supplemental reserves or both. Customers using a load reduction plan may only avoid supplemental reserves and must reduce load by at least 3.5% of the supplemental load level.[18]

Pacific Power's partial service rates encourage efficient consumption and generation in a way that is beneficial for both the utility and the customer because the rates penalize customers with generators that go offline during on-peak periods while enabling a customer to avoid charges on their bill by operating in a manner beneficial for the utility. The rate accomplishes this beneficial incentive system by not ratcheting on-peak demand; tacitly acknowledging the diversity benefits at the distribution level. Ratchets do not encourage efficient consumer rationing nor do they accurately tie a customer to the costs of shared distribution infrastructure.

4.2 Detroit Edison

The second model rate is Detroit Edison's Rider 3: Parallel Operation and Standby Service. This rider uses a monthly generation reservation charge to cover DG capacity, daily on-peak demand charges to be calculated during DG outages and stipulations for outage energy pricing.

Monthly Generation Reservation Fee:

- $1.53 per kW of standby contract capacity

Daily On-Peak Demand Charge during System Outage

- $4.02 per kW during unscheduled outages
- $2.20 per kW during scheduled outages

Energy Pricing

- For certain rates, 4.408₵ per kWh plus any appropriate credits
- Other rates will use the energy charge in the customer's otherwise applicable tariff

[17] Pacific Power prices unscheduled power at the PowerDex Mid-Columbia Hourly Electricity Price Index which is a weighted average of prices reported for a particular hour. The actual price Pacific Power pays for unscheduled energy may vary from the indexed price.

[18] The Western Electric Coordinating Council requires that utilities maintain 7% reserves for thermal resources half of which must be dedicated towards spinning reserves (hence 3.5% for supplemental and spinning reserves).

Rider 3 calculates standby contract capacity using the 1001st highest half-hour on-site generation output.[19] The Detroit Edison rate separately calculates standby contract capacity for the months of June to October and the rest of the year in order to reflect seasonal variations.

4.2.1 Transparency: Use of Daily, As-Used, On-Peak Demand Charge

An important feature of this rate is its use of a daily, as-used, on-peak demand charge in order to recover the cost of demand during an outage. The use of on-peak, daily demand charges enables the utility to recover costs while influencing standby customer performance. The lack of ratchets on such outage demand further incentivizes economically efficient consumption month after month. The difference in price between the unscheduled and scheduled daily demand reflects the fact that unscheduled standby service might be taken at any time without prior notice. This price premium also helps incentivize the maintenance of DG systems and encourages systems that must go offline for maintenance to do so during off-peak periods.

4.2.2 Flexibility: Load Shedding Provision

Detroit Edison provides a load shedding provision that can help a customer further reduce daily outage demand charges. During an on-peak outage, customers may reduce their standby demand by reducing their supplemental load below the maximum monthly on-peak supplemental demand. The rate applies the supplemental load reduction to the standby demand figure used to calculate the daily demand charge.

4.2.3 Efficient Consumption: Buy-Through Standby Option

In addition to the more traditional standby service, Detroit Edison offers a buy-through standby option in which the customer purchases all needed standby demand from MISO. Under this option a customer will pay to the utility a monthly service charge, a distribution charge per kW of standby contract capacity, and kWh adders intended to cover transmission and administrative costs. The buy-through option removes daily demand charges and replaces those demand charges with hourly locational marginal prices (LMP) to be charged when the customer needs standby power.

Instead of contracting with a deregulated supplier, the customer will rely on Detroit Edison to go to market and purchase needed standby demand and energy. The utility will pass these charges directly through to the consumer.

4.3. Other Utilities

Successful standby rates such as those from Pacific Power and Detroit Edison are designed to maximize efficient consumption and consistent cost allocation while being transparent and flexible. Transparency,

[19] Detroit Edison records a customer's DG output in half hour segments. These segments are then ranked from greatest output to least. The 1001st greatest output segment is used as the standby contract capacity. This is done separately for the summer months of June to October. Since Detroit Edison only uses half hour output segments from the previous eleven months the contract capacity is constantly being revised each month.

flexibility, and promotion of efficient consumption are all important principles in the creation of standby rates. Below are examples of rate mechanics from other utilities around the country, including MidAmerican Energy in Iowa, that incorporate these principles.

4.3.1 Transparency

Transparency allows customers a better understanding of the costs of their service and how the utility recovers those costs. Other utilities with transparent rate mechanisms include:

- Portland General Electric Rate 75 (partial service) – distinguishes between shared and dedicated distribution charges. Shared distribution is calculated using a customer's monthly coincident peak demand while the dedicated facility capacity is calculated using the non-coincident peak.[20]
- MidAmerican's new standby rate – Rider SPS – divides the reservation charge into four categories corresponding to generation, transmission, distribution and substation cost causation. A customer's forced outage rate is used to calculate the generation and transmission components.[21]
- Consumers Energy – offers MISO LMP pricing to standby customers.[22]
- NSTAR Rate SB-T2 – separates distribution costs between summer and winter peak, charging a premium for summer peak demand in order to reflect cost differences.[23]
- Consolidated Edison – differentiates distribution demand and daily, as-used standby demand using three time periods during the summer and two during the winter.[24]

4.3.2 Flexibility

Flexibility allows standby customers options that best suit their needs. Flexible rates recover costs from customers who incur them while allowing customers who do not incur costs to avoid charges. Other utilities with flexible rate mechanisms include:

- Georgia Power Rate BU-8 – allows customers to choose either firm or interruptible standby service. Firm service is priced at a premium.[25]
- Pacific Gas and Electric Schedule S: Standby Service – calculates reservation capacity using the outage diversity of a customer's generating unit. PG&E also offers "Physical Assurance" for standby customers.[26]

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[20] Portland General Electric Company, *Schedule 75 Partial Requirements Service*, Sheet No. 75-1 to 75-8 (Effective November 15, 2011).
[21] MidAmerican Energy, *Rider SPS Standby and Supplementary Power Service*, Original Sheet 486 (effective June 16, 2013)
[22] Stanton, 18.
[23] NSTAR Electric, Boston Edison Company, *General Service Rate SB-T2*, M.D.T.E. No. 138C (Effective May 1, 2006).
[24] EPA, A-3.
[25] Georgia Power, *Back-Up Service Schedule: BU-8*, Original Sheet 12.30 (Effective April, 2012).
[26] Stanton, 17. Customers with Physical Assurance guarantee that if their generator units go offline they will automatically and instantaneously drop demand in an amount equal to the generating capacity. In return, these customers pay no reservation charge.

- Both Ohio Power and Columbus Power's Schedule SBS – allows customers to choose their reservation charge corresponding to an allowed use of standby power.[27]
- Southern California Edison – recommends the use of load and demand diversity during distribution peak in order to calculate the backup demand for standby customers.[28]

4.3.3 Incentives for Efficient Consumption

The promotion of efficient consumption is one of the key functions of utility rates. Rates should be created in a manner that incentivizes behavior beneficial to the utility. Other utilities with rate mechanisms that encourage efficient consumption include:

- NSTAR Rate T-2, Portland General Electric Rate 75, and MidAmerican's Rider SPS – have no demand ratchets.
- Orange & Rockland Tariff SC-25 – recovers distribution charges for both the supplemental and standby portion through daily, as-used demand charges.[29]
- Hawaiian Electric Company Rate SS – charges standby customers a fairly high ($0.156/kWh) energy charge during DG outages. This gives the customer a strong and direct incentive to ensure that their generator is well maintained.[30]

[27] Ohio Power Company, *Schedule SBS Standby Service*, Revised Sheet No. 227-1 (Effective March 2012).
[28] Public Utility Commission of California, Rulemaking 99-10-025, Decision 01-07-027 (July 12, 2001), 14.
[29] EPA, 13.
[30] Hawaiian Electric Company, Schedule SS: Standby Service, Sheet No. 69, Effective May 15, 2008..

5. Recommendations

The aforementioned rates and rate mechanics provide examples of rate structures that accommodate cost recovery while being transparent, flexible and economically efficient. These three principles should be considered in guiding IPL to creating future, standby rates that can remove the financial barriers to CHP. Below is a straw proposal outlining how these principles can affect rate design.

Transparent rate :

- The separation of capacity costs to best reflect the drivers of cost for each component: dedicated distribution, shared distribution, transmission, and generation capacity.
- A differentiated transmission charge reflecting the costs associated with on-peak and off-peak periods, especially ITC Midwest allocation of transmission costs.
- Clear, easily understood rate mechanics.

Flexible rates:

- Rates that allow standby customers to remove load during DG outages through physical assurance or some other similar mechanism. Physical assurance contracts should only apply when DG outages coincide with peak periods but not during times of available capacity on the distribution network.
- Rates that incorporate load diversity and outage probability.
- Rates that allow customers to minimize charges by operating in a manner beneficial to the utility.
- If available, the ability to purchase power from real-time markets.

Rates that encourage efficient consumption:

- Charge a premium for unscheduled outage demand that coincides with utility peak.
- Remove ratchets in order to allow customers to ration themselves efficiently every month.
- Recover costs in a manner that penalizes customers who use the grid inefficiently while allowing customer to avoid charges when not taking service.

Rate designs that consistently and accurately allocate and recover utility costs give customers a strong incentive to use electric service efficiently in order to minimize the costs that customers impose on the grid. Rates should also reflect the realities of distributed generation operation. Systems will statistically encounter unscheduled outages; however, the costs these outages impose on the grid can be minimized through diligent maintenance and well-crafted standby rates. Standby flexibility, for example, could allow customers that primarily need scheduled maintenance service to pay less than customers who need a greater amount of unscheduled backup service since the price to provide these two services can differ immensely. Instead of a one-price-fits-all approach, there could be a mechanism to incentivize DG customers who have the ability to limit their use of standby service to periods in which utility costs are minimal. That same mechanism, however, should also be used to penalize standby customers who incur great costs to the utility.

The principles delineated above are meant to be used as guidelines to help shape future standby discussions. If IPL's future standby tariff can be structured in a way that recovers costs while being transparent and flexible as well as efficient, this could reduce the barriers to customer-sited, energy efficient CHP systems.

6. Conclusion

The structure and mechanics of standby rates can greatly impact the financial viability of combined heat and power and other distributed generation projects. Non-optimal rate design can force DG customers to operate inefficiently or uneconomically. In some instances, customer-sited generation must permanently go offline due to onerous standby rates. A 2012 study by the Midwest CEAC concluded that Interstate Power and Light's standby rates posed a financial barrier to the viability of distributed generation projects. In further analyzing IPL's tariffs, this paper found that there are no price signals incentivizing customers who utilize grid power economically. Customers who exert vastly different demands and therefore cost on the utility, may pay the exact same amount. In other words, customers that use the grid in a manner that drives costs may pay the same amount as customers who use the grid in a way that incurs significantly less cost.

IPL's current standby rates reflect a situation that has since changed with the sale of Alliant Energy's transmission assets to ITC Midwest. Instead of encouraging the beneficial behavior of CHP and DG systems and more precisely assessing cost incurrence, current rates act as financial barriers toward any implementation of customer-sited distributed generation by inconsistently and, in some cases, unfairly allocating and recovering costs for standby customers. Inconsistent rate mechanisms include IPL's methodology for billing transmission standby reservation capacity, the lack of consideration for a customer's forced outage rate, and the unavailability of market options.

While specific rate structures and cost recovery mechanisms can be largely unique to each utility, there are overarching principles that are universally applicable. Transparency, flexibility, and the promotion of economically efficient consumption are guiding principles that help to more consistently and beneficially allocate and recover costs, specifically those of distributed generation and combined heat and power customers. These principles allow a utility to recover their costs in a manner that specifically targets the loads that drive investment and cost. The rate structures used by Pacific Power and Detroit Edison offer examples for how these principles translate into rates themselves; however, there are many other sources to which IPL, the Iowa Utilities Board, the Office of Consumer Advocate and other stakeholders can look for guidance. Table 1 provides a summary of the analysis of IPL's current standby rates and compares these rates to successful approaches of standby rate structures in other utilities.

In 2014, IPL may file a rate case. This possible rate case presents opportunities for IPL to consider other options for its standby rate structure.

Table 1: Summary of IPL Standby Rate Barriers and Successful Approaches to Standby Rate Structures by Other Utilities

Principle	Identified Factor	Analyzing Interstate Power and Light's Standby Rates	Successful Approaches to Standby Rate Structures by Other Utilities
Transparency	Transmission Cost Allocation	IPL allocates transmission costs for standby customers using an excess and average methodology even though transmission owner, ITC Midwest, allocates costs to IPL using a coincident peak methodology. Standby customers are assessed transmission charges every month even if they do not use the transmission grid during peak periods.	Pacific Power in Oregon assesses transmission costs using on-peak methodology. This more accurately reflects the costs of providing transmission service. MidAmerican Energy in Iowa calculates the transmission reservation charge using a customer's forced outage.
	Unbundling Reservation Rate	IPL unbundles their reservation rate into generation, distribution and transmission components.	Portland General Electric further unbundles their distribution charge between shared and dedicated distribution infrastructure. A customer's FOR is then applied to the shared distribution component. NSTAR separates distribution costs between summer and winter peaks reflecting difference in cost incurrence.
Flexibility	Load Shedding Provisions	IPL allows standby contract capacity to be set by the customer.	Pacific Power employs mutually agreed upon standby contract capacity including opportunities for standby customers to self-supply reserves or install a load limiting device.
	Daily As-Used Demand Charge	IPL provides daily as-used demand charges for schedules outages only.	Orange and Rockland recover all standby distribution charges through a daily as-used demand charge.
Promoting Efficient Consumption	Use of Forced Outage Rate to Calculate Reservation Charge	IPL does not incorporate a standby customer's forced outage rate in the calculation of the reservation charge.	Pacific Gas and Electric incorporates outage diversity into the calculation of a standby customer's rsvp charge. MidAmerican Energy calculates the generation and transmission component using a customer's FOR. AEP in Ohio allows a standby customer to choose their outage level reservation rate.
	Demand Ratchets	IPL employs a 75% peak summer demand ratchet.	NSTAR (MA), Portland General Electric (OR) and MidAmerican (IA) employ no demand ratchets in their supplemental tariff.

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