FORGING A PATH TO THE MODERN GRID

ENERGY-EFFICIENT OPPORTUNITIES IN UTILITY RATE DESIGN

ALLIANCE TO SAVE ENERGY
using less. doing more.

Rate Design Initiative

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ACKNOWLEDGEMENTS

This document is a product solely of the Alliance to Save Energy. The Alliance is a bipartisan coalition of government, industry, academia and civil society interests working together to improve energy productivity to strengthen and expand economies, improve the environment and enhance energy reliability and security.

The following white paper, while solely a product of the Alliance, was deeply informed by the core participants of our Rate Design Initiative. We are grateful for the valuable resources, contributions and insights of the 30+ organizations and individuals that shaped this report, including a wide variety of advocacy organizations, industry associations, technology companies, think tanks, regional partnerships and utilities. It is important to note that, among these stakeholders, there is a considerable divergence of opinion regarding the path forward for utility design.

Further, the recommendations in this report are not intended to prescribe any specific policy, but merely to inform policy decisions. As such, they are not intended for use in specific rate cases.

Finally, thanks go as well to the many Alliance team members, past and present, whose work underpins this important, proposed new way forward on rate design, which we believe will encourage demand side efficiency and system energy efficiency alike, to the benefit of all stakeholders.

KATERI CALLAHAN

President

Alliance to Save Energy

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Utilities will begin the journey to a modern grid from different starting positions and with different factors that control the pace and character of the transition.

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EXECUTIVE SUMMARY

The past decade has seen a convergence of technology, policy and economic trends that have directly impacted the energy sector. New appliance standards and building codes have reduced the amount of energy we use. New communications and information technology have transformed electricity delivery and use from the analog world to the digital world. Prices for renewable generation have fallen; for example, solar PV prices have fallen by more than 60% since 2010,[1] and the cost of wind projects have fallen by more than 90% since the early 1980's.[2] As a result, electricity sales for the U.S. utility industry have been flat for years and the carbon intensity of the power grid fell by 21% between 2005 and 2015.

Through it all, utility companies have been working to maintain safe, reliable and affordable service. But the way utilities have traditionally recovered much of their costs – through flat volumetric pricing (cent per kilowatt-hour), especially for residential and small commercial customers – is increasingly out of step with the needs of both the utility companies and the customer base they serve. As efficiency and distributed generation continue to put downward pressure on sales and in the absence of frequent rate increases, reliance on traditional, flat volumetric pricing makes it increasingly difficult for utilities to recover the fixed costs of existing assets and new investments needed for replacing aging infrastructure.

Fortunately, the same technology and policy trends that are driving this misalignment can be called upon to help solve the problem. The Alliance believes that the transition to a grid that is reliable, resilient, decarbonized, automated, transactive, efficient and equity-driven (hereinafter referred to as a "modern grid") can be enabled through good rate design.

Appropriate combinations of rate designs and other ratemaking policies can support an increasingly clean energy system without detriment to reliability, exorbitant costs to consumers or degradation of utilities' financial stability. Other benefits could emerge as well. System utilization would increase as customers manage their peak demand and provide headroom to bring on additional electrification of end uses. Price signals can more closely correspond to system costs, providing the correct incentives about what to deploy and where to deploy it. Customer rates can be managed due to an increase in energy supplies with zero fuel costs. And tying it all together will be the utility, coordinating the many pieces of technology that are plugged into its grid.

There are a number of elements that will be important for attaining this vision, however: demand flexibility will be critical; cost-effective energy efficiency must be aggressively deployed everywhere; and zero- and low-carbon generation must play a part in both the bulk power grid and the local distribution grid. The ability to manage customer loads through demand-side management will be critical to balancing supply with load. Energy storage (both thermal and electrochemical) will play multiple roles, including maintaining power quality on the system.

Also, products, services and markets must be developed and commercialized to coordinate everything, policies must be in place to shape the move toward a modern grid and rate design must support all these activities.

Energy efficiency will continue to be a critical means to reduce the need for electricity generation. But we expect that to some degree in the future, the nature of achieving efficiency will change so that it focuses on not only ***how much*** electricity is used, but also ***when and where*** it is used. To ensure that this transition happens in a way that optimizes the deployment of all types of system resources, prices that recognize the possibility of bi-directional price signals, power flows and geographic and temporal costs are increasingly important.

It is within this context that the Alliance to Save Energy (Alliance) convened the Rate Design Initiative (RDI), with input from a diverse set of rate design stakeholders, to develop principles and recommendations for rate design that can serve as a near-term guide for policymakers and regulators to help align their decisions with policy goals as they examine these complex issues in their own jurisdictions.

All parties participating in the Alliance's discussions fully acknowledge that a singular proposal will not apply to all markets. However, the core participants did reach consensus on a set of principles designed to drive future innovation in Demand Side Management (DSM) services and business models in response to changing customer needs and the evolution of distributed energy management, generation, storage and control technology. These are:

- Rate designs should include the ability to collect for the use of the energy grid and to compensate customers for investments that provide verifiable local and system-wide cost savings compared to alternatives.
- Rates should be designed, to the extent possible, to reflect the real-time, localized costs of service while assuring equity, limiting complexity and minimizing rate shock.
- Rates that more accurately reflect the costs and savings resulting from time- and location-dependent demand management should be introduced as a platform for delivering innovative new energy services to customers.
- Utility business models should be complementary with state energy goals and priorities.

Based upon the principles developed with full consensus of the core RDI participants and consistent with its mission, the Alliance has set forth proposed elements to consider for a transitional rate design for those utility systems with advanced metering infrastructure (AMI) and for those without it.

It is critical to note, however, that **this white paper was not prepared with specific ratemaking or regulatory proceedings in mind; it should not be cited by any party in a specific ratemaking or regulatory proceeding as evidence that the Alliance endorses any specific proposal.**

Although many commercial and industrial customers today are served today by three-part tariffs, which include a customer charge, a demand (or kW) charge and a volumetric (or kWh usage) charge, the majority of residential and small commercial (collectively, mass-market) customers are served on traditional two-part tariffs comprised of customer and flat volumetric charges. The consensus of the RDI core participants is that the latter rate design will not assist us in transitioning to the modern grid that will benefit all customers in the future.

Revenue decoupling is an important policy in many jurisdictions for many reasons, but the RDI participants stressed that it is insufficient to accomplish the needed transition and should not be viewed as a substitute for good rate design. At its core, revenue decoupling breaks the link between utility sales and revenue. By adjusting rates up or down depending on actual sales, decoupling ensures that the proper revenue will be recovered by utilities. In the short term, this can protect consumers from over-recovery if there is a hot summer and can protect utilities against under-recovery if energy efficiency programs are more effective than anticipated. The Alliance concludes on this issue that if rate design better aligns costs with prices, it will be complementary to the choice of decoupling as a policy tool.

This report provides tools to stakeholders at the start of the journey to a modern grid; extensive analysis, pilot programming and stakeholder outreach and education will be necessary to complete it.

Alliance to Save Energy Points for Consideration

Utilities will begin the journey to a modern grid from different starting positions and with different factors that control the pace and character of the transition. Some states already have in place technology (such as AMI) and policies (such as revenue decoupling) that will enable this transition to occur more quickly than others. Some states may have laws or regulations that must be considered in concert with changes to rate design. In all cases, utilities must be responsive to the concerns of their stakeholders and the precedents of rate-setting bodies.

Within this document, the Alliance provides a starting point for parties considering a new rate design, including elements of a *transitional rate design* that will encourage customers to manage their demand, including through both energy efficiency and demand response, while allowing utilities the opportunity to earn the revenues required for maintaining a safe, reliable, affordable, clean and sustainable grid. To do this, there must be a balance between encouraging demand-side efficiency and system energy efficiency, to the benefit of all. Key considerations include:

1. **The Alliance maintains that the development and implementation of any specific policy must be rigorously analyzed and tested against the "North Star" objective of maximizing system energy efficiency and reaping societal benefits, including minimizing greenhouse gas emissions and maintaining affordable energy access for all.**

2. **The Alliance recommends that as a utility and its stakeholders consider whether and how to pursue a more advanced rate design, analyses and pilot programs should be conducted to gain real-world experience on how customers respond to rate design changes.** These pilots should also test the effectiveness of different enabling technologies such as home automation systems. To the extent that this process demonstrates that the rate designs indeed prompt shifts in energy use and do not disproportionally impact subclasses of customers (such as low-income customers or urban apartment residents), the results can be used to design a rate structure that combines the most effective elements.

3. **The Alliance recommends that aggressive customer-education programs precede the deployment and roll-out of new rate designs.** Such programs are a key and critical element to ensure that customers understand how best to manage their usage under a new rate structure before the new rates are implemented system-wide.

4. **For jurisdictions that do not have AMI, the Alliance proposes a rate structure that incorporates a customer charge plus a seasonal Time of Use (TOU) rate (with cent/kWh charges that vary by season of the year).** In the absence of real-time metering capability, this

rate structure represents a sound balance among numerous goals: encouraging demand-side energy efficiency, economic efficiency and system energy efficiency, sending price signals to customers about the cost of service and providing revenue sufficiency for utilities. For those utility systems without the technical capability to implement more granular pricing, tiered rates with seasonal variation in pricing are superior to flat volumetric rates in two ways: (1) these rates more accurately assign capacity-related costs to the time of year when those costs are incurred; and (2) they link total energy use to peak demand, more accurately assigning peak demand costs to customers likely to be using the system during peak times.

5. **Where AMI is fully deployed, the Alliance recommends implementing three-part rate pilot programs, and if these are successful, the full consideration of a modified, three-part rate structure as a means of transitioning to the modern grid.** All customers, including residential and small commercial customers, could have a customer charge, a demand charge and a volumetric charge. The customer charge would collect revenues for customer-related costs. The demand charge would be based on clear and demonstrable evidence of cost causation and designed to create incentives for customers to both use the grid as efficiently as possible and to shift usage from high-cost to low-cost periods, thus lowering overall system supply and delivery costs and improving overall system energy efficiency. The volumetric charge would be a time-of-use rate with kWh charges varying during three time periods per day.

   The Alliance believes that such a rate design could be constructed to:

   - continue to provide consumers with the incentives and ability to control their energy costs;
   - increase economic efficiency and system energy efficiency;
   - send appropriate price signals to the market for demand-side management investments;
   - help customers participate in improving the efficiency of the system as a whole, delaying or avoiding altogether the need for costly incremental infrastructure investments; and
   - enable utilities the opportunity to earn a reasonable rate of return on their assets.

In this white paper, the Alliance to Save Energy offers suggestions on how states, utilities and other stakeholders could move forward to modify and transition rate designs for mass-market customers to make progress toward a modern grid. We believe that the sooner we begin down this road, the smoother the transition will be.

Rate design is one of the most critical elements of our modern energy landscape as it provides the framework for resources to ensure adequate utility services to customers. Get rate design right and solve multiple challenges simultaneously.

2

INTRODUCTION

The electric utility sector is experiencing a confluence of forces unmatched in recent history. Technology is evolving rapidly. Prices for renewable generation have fallen and the penetration of distributed generation is on the rise. Electricity sales are flat and in some areas of the country, falling. Data analytics are emerging as a powerful tool. Connectivity inside and outside of the home is increasing. And through it all, consumers are becoming more educated and more demanding.

Against this backdrop of factors, the Alliance convened the Rate Design Initiative (RDI), comprised in its first phase of a group of experts and thought leaders from utility companies representing both vertically integrated utilities and distribution utilities operating in restructured states and energy service and product providers. They were joined in conversations in Phase 2 by consumer advocates and former state public utility commissioners, to test ideas and principles against today's regulatory practices. In Phase 3, additional stakeholders including national organizations such as NASEO and NARUC, energy efficiency advocates, public power representatives, regulatory experts and regional energy efficiency organizations contributed to the dialogue. Our primary goal was to design near-term (3-5 years) rate recommendations that could achieve four outcomes: (1) continue to incent cost-effective investment in efficiency and demand-side management technologies and services; (2) incent utilities to innovate and adapt legacy systems to the rapidly evolving sector to minimize financial stress as they execute on their mandate to provide safe, reliable, affordable, clean and sustainable energy; (3) reduce total greenhouse gas emissions in the utility sector; and (4) accomplish this with minimal cost impact to customers.

As part of the Utility Rate Design Initiative, the Alliance to Save Energy executed two technical analyses and a review of literature. The first analysis investigated OpenEI's U.S. Utility Rate Database, an open-source utility tariff database, while the second analyzed the Energy Information Administration's Form 861 data. Additionally, the Alliance reviewed approximately 35 white papers and technical documents that helped inform and shape this position on rate design.

Rate design is one of the most critical elements of our modern energy landscape as it provides the framework for resources to ensure adequate utility services to customers. Get rate design right and solve multiple challenges simultaneously. Get it wrong and consumers, businesses and entire industries suffer. The rate design considerations we propose herein are intended to enable the future grid: one that is reliable, resilient, decarbonized, automated, transactive, efficient and equity-driven among consumers (hereinafter referred to as the "modern grid"). But, the recommendations in this report are not intended to prescribe any specific policy; rather, they are suggested to inform policy decisions. As such, these suggestions are not intended for use in specific rate cases.

In this carefully-designed process, the Alliance researched the evolution of rate design, concentrating on the most recent five years, then worked with Phase 1 participants to arrive at a set of principles for a transitional rate design. From these principles and based on feedback in Phases 2 and 3 of the initiative, the Alliance staff developed the rate design considerations discussed herein.

RDI distinguished rate design for utilities with and without advanced metering infrastructure (AMI or “smart meters”),[3] and in vertically integrated versus restructured markets.[4] AMI enables additional rate design opportunities, such as dynamic pricing and demand rates, which are technologically unavailable through legacy analog meters. Where appropriate, we have included separate considerations for utilities with and without AMI.

The scope of the RDI was focused on actions that parties could take in the nearer term and limited to demand side management (DSM). This choice intentionally excluded distributed generation and next-generation utility business models (such as the 21st Century Utility, New York REV and the 51st State Initiative) from the scope, to keep the document sufficiently focused to be of immediate use to regulators and other stakeholders. We also instituted a process to back-check our templates against other current and developing issues in the utility rate design space. We have examined our recommendations’ impact on distributed generation deployment and resilience to utility business model changes, finding any impacts to be relatively minor. This additional validation will make the RDI recommendations more robust as technology and policy continue to bring change to the energy sector.

2.1. BACKGROUND

The past decade has seen a convergence of technology, policy and economic trends that have directly impacted the energy sector. New appliance standards and building energy codes have reduced the amount of energy we use. New communications and information technology have transformed electricity delivery and use from the analog world to the digital world. Distributed generation prices have fallen – for example solar PV prices have fallen by more than 60% since 2010,[5] leading to a rapid increase in the deployment of distributed energy resources (DER). Costs of wind energy have declined more than 90% since the early 1980’s.[6] The culmination of these trends is that electricity sales for the utility industry have been flat or falling and the carbon intensity of the power grid has fallen by 21% between 2005 and 2015.

Through it all, utility companies have been working to maintain safe, reliable and affordable service. But the way utilities have traditionally recovered much of their costs – through flat volumetric pricing – is increasingly out of step with the needs of both the utility company and the customers they serve. As demand side management and distributed generation continue to put downward pressure on sales, reliance on traditional volumetric pricing makes it increasingly difficult for utilities to recover the fixed costs of existing assets absent frequent rate increases.

Certainty around cost recovery is becoming increasingly important given the additional investments that utilities are making to secure resilience, integrate advanced grid technologies and support integration of distributed energy resources. The utility industry has been trying to solve this issue for years. Reports have examined these trends in the past 3-5 years, some suggesting a solution where customers pay for grid access through a fixed charge, one that was substantially higher than contained within most utility tariffs at the time. While this would help solve the risk to revenue recovery problem for utilities, by itself it would dramatically reduce the financial incentive for consumers to reduce their energy use, as their savings from such measures would be reduced.

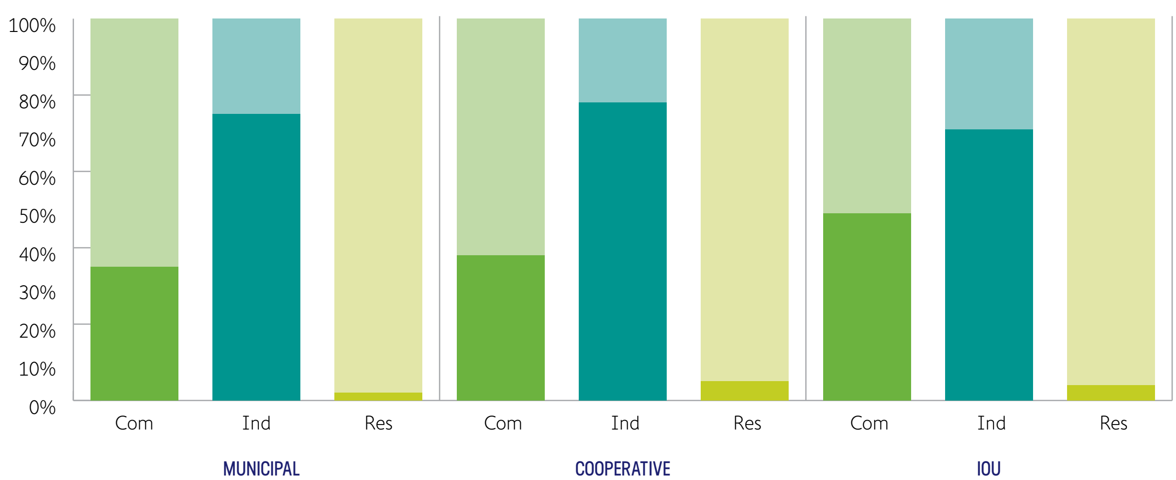
As utilities began to request higher fixed charges in rate cases around the country, many stakeholders intervened, and policy and academic institutions published papers arguing against such increases.[7] Overall, the push for significantly higher fixed charges has been met with substantial resistance. While some utilities have received partial increases for the fixed portion of the bill in rate cases, most were smaller than requested and others were denied entirely.

In some jurisdictions such as New York, Minnesota, California and Massachusetts, some have suggested that the distribution utility should be viewed as the central integrator of resources and all stakeholders should collaborate to achieve policy goals, including a shift from focusing on historic rates to a more forward-looking focus on planning, accountability and incentives for results.

More recently, the increasing penetration of advanced metering infrastructure (AMI) and the emergence of technologies that enable customers to respond to dynamic prices without needing to take direct action have shifted the debate from increased fixed charges to deploying demand charges for all customer classes. Demand charges, which are a cost component based on the customer's peak usage within a given time frame have the potential of providing a direct economic signal to customers to adjust their energy use. However, while demand charges have long been a part of large commercial and industrial tariffs, they have been used rarely for residential and small-commercial customers, known collectively as mass-market customers; and where implemented, virtually all are voluntary options. This was a topic of much discussion among the RDI participants and the subject of substantial background research conducted by the Alliance.

Today, the use of seasonal or monthly demand charges varies by consumer class: they apply to over 70% of industrial tariffs; 35%–50% of commercial tariffs; and single-digit percentages for residential customers, usually through voluntary, opt-in programs with low participation levels.

TARIFFS WITH SEASONAL/MONTHLY DEMAND CHARGES



Source: Alliance To Save Energy analysis of OpenEI Utility Rate Database

We find ourselves in 2018 facing many uncertainties. With accelerating innovation in energy technology and in communications, it will be critical to ensure the regulatory environment and utility companies' business models are able to keep pace with the rapid evolution of the energy sector. With this context, the Alliance has developed rate design considerations to help inform policymakers and regulators as they examine these complex issues in their own jurisdictions.

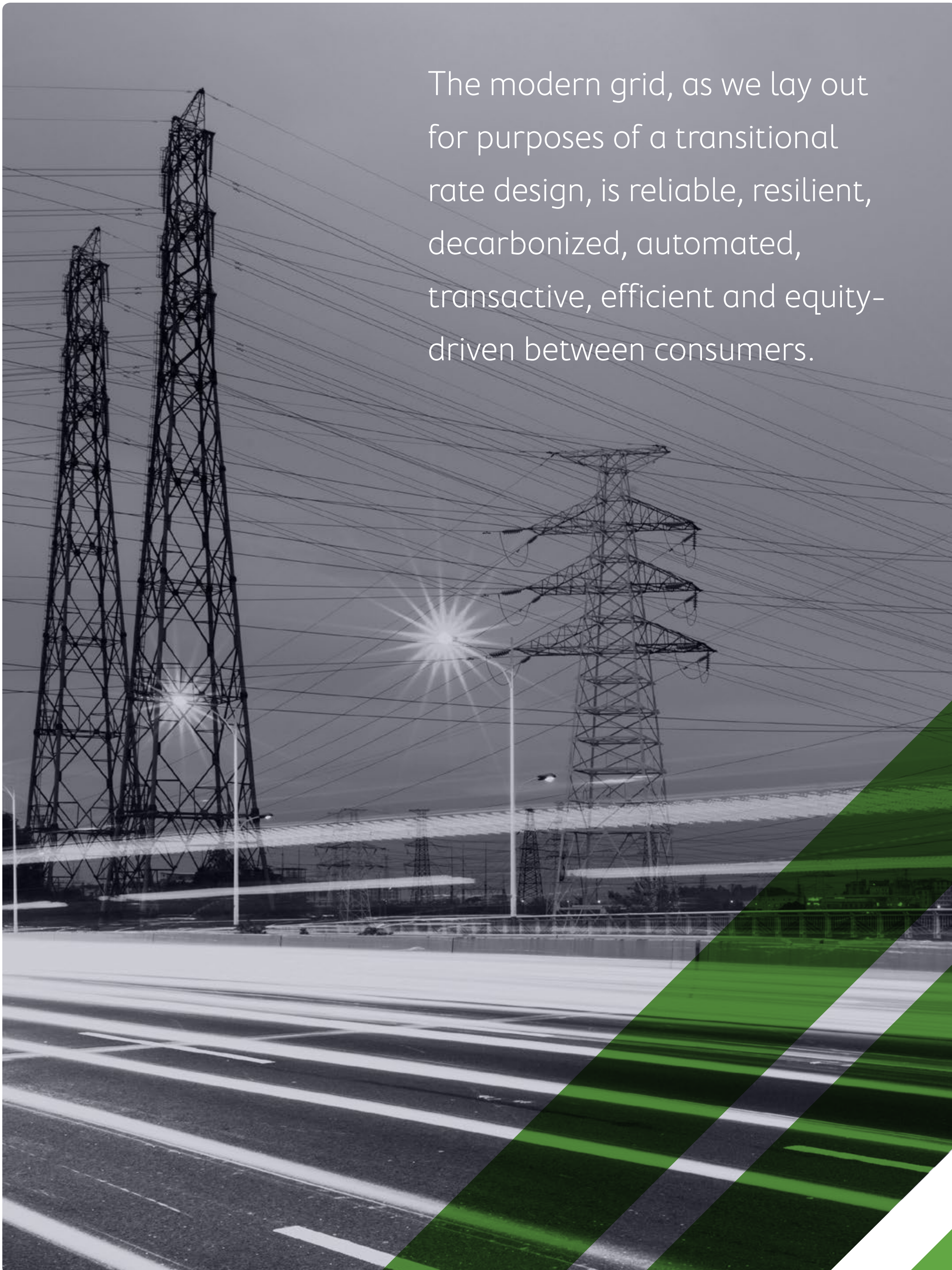
2.3. RDI PRINCIPLES

In October 2016, the Alliance published a Statement of Principles — the consensus product of the first phase of the RDI — which included a diverse set of utility companies and energy service and product providers. These companies represented both vertically integrated utilities and distribution utilities operating in restructured states. Though these principles were prepared with a focus on the advancement of demand side management (DSM), many of them reflect valuable guidance for the approach and objectives of rate design, overall:

- Rate designs should include the ability to collect for the use of the energy grid and to compensate customers for investments that provide verifiable local and system-wide cost savings, compared to alternatives.
- Rates should be designed, as much as possible, to reflect the real-time, localized costs of service while assuring equity, limiting complexity and minimizing rate shock.
- Rates that more accurately reflect the costs and savings resulting from time- and location- dependent demand management should be introduced as a platform for delivering innovative new energy services to customers.
- Utility business models should be complementary with state energy goals and priorities.

2.4. BEGINNING THE TRANSITION

We are acutely aware that states vary in policies and precedents and that some of the suggestions herein may not be possible to implement in certain jurisdictions. We also acknowledge the substantial local variability in the role of specific stakeholders; the varying stages of technical development and DSM penetration; and fundamental differences between the types of service required in a rural cooperative versus an urban investor-owned utility. However, we believe that there is still added value in exploring and clarifying the opportunities for rate design that have been playing out in rate cases across the country. This document is intended to be a starting point for discussions among stakeholders rather than a prescriptive set of conclusions.



The modern grid, as we lay out for purposes of a transitional rate design, is reliable, resilient, decarbonized, automated, transactive, efficient and equity-driven between consumers.

3

ENABLING TOMORROW'S GRID

When trying to determine what steps for rate design should be taken in the near term, it is often instructive to imagine a modern grid of the future (which we will refer to hereafter as the "modern grid") and work backward. Having laid out the destination, one can then chart the path from today and foresee potential roadblocks. Of course, this approach necessarily requires one to define the future vision.

The modern grid, as we lay out for purposes of a transitional rate design, is reliable, resilient, decarbonized, automated, transactive, efficient and equity-driven between consumers. This future state may require legal, regulatory, business model and technical changes to the current paradigm and it is probable that even this scenario will change as technology evolves. Thus, the rate design elements proposed here should be considered as transition mechanisms to use as a placeholder as we begin to understand more of what the final destination looks like and as technology and policies continue to evolve.

The transition to the future state assumes several prerequisites, based on Alliance views as well as those of many stakeholders consulted in the process:

- **Accelerating the decline in carbon emissions is vital to the nation's interest.** The implementation of a new rate design can lead to different short-, medium-, and long-term direct impacts on carbon emissions, and they should be explicitly assessed, analyzed, and minimized.
- **Demand-side efficiency, economic efficiency and system energy efficiency** will continue to be a critical means to reduce the need for fossil-fuel generation.
- Achieving this efficiency will **expand the focus on how much electricity is used to more deeply address *where* and *when*** it is used.
- To ensure that this transition happens in a way that **optimizes the deployment of all types of system resources** – and at the same time protects consumers across all rate classes and levels of technology adoption – **it will be paramount to send clear, bi-directional pricing signals** that reflect geographic and temporal costs and benefits.
- **Demand flexibility** will be critical and cost-effective energy efficiency should be used in a way that **maximizes system energy efficiency**. Demand-side management resources will be critical to balancing supply with load.
- **Cost-effective energy storage** (both thermal and electrochemical) could play multiple roles, absorbing excess zero-carbon energy for use when needed and maintaining power quality on the system. Products, services and markets must be developed and commercialized to coordinate everything.
- The implementation of new rate designs **must not jeopardize access to affordable electricity** for vulnerable communities and low-income households. Low-income households are the least able to accommodate higher utility costs and make up-front investments in energy efficiency. State utility commissions

have traditionally assigned a high priority to assuring access to affordable energy for all ratepayers, but especially low-income households. Any new rate designs and supporting policies should reflect this priority and ensure continued access for low-income households to affordable and reliable utility service.

The rate design must support all these activities.

Done correctly, this rate would result in decarbonization without detriment to reliability, exorbitant costs to consumers, or degradation of utilities' financial stability.

4

COMPONENTS OF THE TRANSITIONAL RATE DESIGN

It is a central facet of market design that rates must send appropriate price signals. Given the more dynamic nature of the modern grid, it is unlikely that traditional two-part, flat volumetric rates will serve this purpose. Instead, a more complex rate design is needed and tools to enable customers to manage its complexities will also be necessary.[8] For jurisdictions that have advanced metering, the Alliance proposes consideration of a modified, three-part rate structure, for all customers, including mass market customers:

1. A **customer charge** to collect revenues for customer-related costs.
2. A **demand charge** that is designed to incentivize customers to both use the grid as efficiently as possible and to shift usage from high-cost to low-cost periods, thus lowering overall costs and improving overall system energy efficiency.
3. A **volumetric charge** that is a three-period time varying rate, with baseload, mid-merit and peak generation costs as well as common distribution and transmission costs allocated to corresponding periods.

This rate design balances the many challenges that both current and future stakeholders will face. It will increase demand side efficiency, economic efficiency and system energy efficiency, will send appropriate price signals to the market for DSM investments, will provide consumers with the incentives and ability to control their energy costs and will enable utilities the opportunity to earn a reasonable rate of return on their assets.

Done correctly, this rate would result in decarbonization without detriment to reliability, exorbitant costs to consumers, or degradation of utilities' financial stability. Other benefits could emerge as well. System utilization would increase as customers manage their peak demand and provide headroom to bring on additional electrification of end use. Bi-directional price signals could more closely correspond to system costs and benefits, providing the correct incentives to the market and to customers about what to deploy and where to deploy it. Customer bills could be managed due to an increase in energy supplies with zero fuel costs. And tying it all together will be the utility, coordinating the many moving pieces of technology that are plugged into its grid. A "postcard" from this modern grid, describing the energy use of an example individual, is included in Appendix A.

Changes in rate design are often complicated for consumers. For the proposal outlined below, outreach to customers and stakeholders, pilot studies to identify efficacy and impacts and educational campaigns will be critical. And for every part of the rate, customer technology must be deployed to handle these changes in a seamless manner and tools enabling customers to budget and manage these charges over time will be necessary.

4.1. CUSTOMER CHARGE

A customer charge (also called a fixed charge) is a recurring charge that appears on a utility customer's bill each month, independent of actual usage. Customer charges typically vary based on customer class and the cost of serving an individual customer's account, with residential customers paying a small fixed fee and commercial and industrial (C&I) customers paying a larger fee.

The proposed transitional rate has a customer charge sized to recover customer-specific costs. While this simple statement might be obvious, its implementation is far from universal. The full costs of certain customer-specific utility functions, such as billing and meters, are not always recovered through a fixed customer charge. Some participants in RDI asserted that customers simply should be able to access the grid for the costs of connecting to the grid. While there was no consensus on the scope of these costs to connect to the grid, the Alliance believes that utilities should be afforded recovery of these costs from all customers connected to the grid, independent of their actual use over the course of the billing period. For purposes of scope, the Alliance recommends customer-specific functions should include billing, meters and meter drops and customer services provisions. This would cover what is clearly and demonstrably dedicated to customer-specific charges and focus on the ability of customers to control their bills through energy use curtailment and other demand side management practices.

4.2. DEMAND CHARGE

In contrast to volumetric rates, which measure the amount of overall energy consumed by a customer over time, demand charges are flat assessments based on the highest level of power consumption, usually over the course of an hour, for a given billing period. For example, a customer that consumes 100 kW of power consistently over a month (such as a 24-hour warehouse) and a customer that consumes 100 kW of power for only one hour of the month (such as a farm irrigation system) would accrue the same demand charge for that month. Demand charges can send a price signal to the consumer to reduce the maximum consumption loads by shifting power consumption to lower-demand periods.

Though demand charges have been common in industrial and commercial tariffs for decades, they have been rarely used for mass market consumers. In recent years, the question of "whether and how" demand charges should be employed for mass market customers has been the source of diverse perspectives and controversy, as can be seen in many rate cases across the country, as well as among the RDI stakeholders consulted in the drafting of this report.

However, it is widely accepted that to truly begin the path to enable more economic efficiency and system energy efficiency to the benefit of all, customers and markets must be provided with the price signals to increase demand flexibility. With the advancement of technologies to help customers manage the complexities and costs of their energy use, demand charges can play a critical role in providing the market with the required price signals and for minimizing the need for additional peak and super peak generation. When customers decrease or spread out their usage based on price signals, this helps the utility to manage system load and can help to delay or avoid the incremental costs of new infrastructure – be it transmission, distribution or generation. Demand charges, when deployed effectively, allow customers to participate in the process of system efficiency, therefore keeping costs down for themselves and for all stakeholders. The Alliance believes that this new component of rates for mass market customers may bring new opportunities for energy efficiency; however, where used, they must be carefully implemented, to ensure that customers receive appropriate price signals that encourage them to act to increase the efficiency of their energy use.

And as stated prior, efficiency is not the only objective of proper rate design. Care must be taken to evaluate and mitigate to the extent possible any impacts of a change in rate design on potentially affected vulnerable communities least able to afford those changes. Such mitigation could occur through education, transition periods, technology implementation, and special efficiency and rate programs for targeted customer groups. And any changes in rate design, including the implementation of demand charges, will impact the way in which customers use electricity and thus how the utility supplies electricity. Thus, rate design changes must be evaluated to ensure positive environmental impacts will result, including reduced emissions of greenhouse gases.

There are multiple ways in which demand charges can be implemented and different strategies will have different impacts. For example, the optimal strategy depends on the structure of the utility. A regulated, vertically-integrated utility likely uses bundled rates, while a restructured utility that operates in organized markets is more likely to focus on distribution system rates. In the latter case, generation and transmission costs are primarily passed through to customers from the RTO or retail supplier.

The timing of a customer's peak demand is another element that can inform demand charge design. A customer's maximum individual demand is called their non-coincident peak (NCP). Local distribution costs including meters, service drops and transformers, must be sized to meet the NCP demand of a customer. Service leading to the customer transformer is provided via secondary lines, poles and transformers and are sized depending on the coincident peak load

MEASURING CUSTOMER DEMAND

Measurement of customer demand takes four primary forms: system coincident peak (CP), utility CP, class CP and non-coincident peak (NCP). System CP demand refers to the customer's usage during the peak of the broadest balancing area in which a utility operates. For many utilities, this might be the regional transmission organization (RTO) or independent system operator (ISO). System CP demand is a measure of how much supply is needed in the bulk power grid to meet the highest simultaneous load.

Utility CP demand is the customer's usage when the utility system itself is experiencing a peak. This time might be different from the system peak. For example, one utility may experience a seasonal peak in winter, whereas the entire region peaks during the summer. Utility CP demand enables utility planners to ensure that there is sufficient power from the bulk power grid to be delivered to customers.

Class CP represents a customer's usage when their customer class (i.e. residential or commercial) is peaking. Class CP is a useful concept in cost allocation and distribution system planning, as business districts are often served with a different set of equipment than are rural or suburban residential neighborhoods. It should be noted that some utilities also define customer class differently for residential customers, for example, separating those with electric space heat from those without.

NCP demand is strictly related to a customer's individual peak usage for a given period and is not based on when the system, utility or class might be peaking, although it might correlate more to the class peak. NCP typically corresponds to the billing period for a customer. If a customer were billed monthly, they would have one NCP value per month.

of all customers on that distribution feeder. At higher voltage levels, service to these distribution facilities is provided through equipment that is sized more closely to the utility coincident peak. A good example would be transmission network facilities and high voltage level networked distribution facilities. Ultimately, power is supplied to the network from generation facilities that are built to meet the system's or utility's coincident peak (CP).

It is undisputed that demand (whether NCP or CP) has a direct correlation with costs. However, the most effective way to recognize these costs in rate designs may depend on individual customer characteristics, system attributes and policy objectives. Theoretically, demand charges could be designed based on NCP (which sends a price signal to reduce maximum consumer consumption levels) or on CP (which, when tied to the system peak, sends a price signal to reduce those consumption levels that impact peak power generation).

Utilities that advocate recovering demand-related distribution costs through demand charges rather than through volumetric tariffs have asserted that this method better reflects a customer's actual use of the grid and contribution to system costs and increases the economic efficiency of rate design. Parties who disagree state that the most commonly proposed approach (NCP demand) does not reflect cost-causation principles, as it does not charge based on usage during utility or system peaks and is difficult to manage and confusing for the average residential customer. Still others in the RDI discussion have asserted that no use of demand charge is acceptable for mass-market customers, as it diminishes the volumetric portion of the bill, creating a less direct energy efficiency price signal and benefit.

The Alliance, as an energy efficiency advocate and convener of this group, accepts the well-made points across the spectrum. At the core of this issue is whether education and technology can support the ability of customers to understand and respond to these rates and whether these rates should be based on CP or NCP demand. Consistent with the goals and principles of this initiative, the Alliance believes demand charges can be explored for a portion of the distribution charges, assuming that both pilot programs and educational campaigns have been undertaken and technology can automate choices. With the broad implementation of AMI and the data it provides, the answers to these issues will become clearer and provide sufficient information to regulators who choose to pursue this path. The choice of demand charge structure – such as the key question of whether to base the charge on CP or NCP – lies beyond the scope of this paper and should be based on evidence presented regarding the efficiency and demand response effects of the approach proposed for the various components of costs for which rates are being designed.

A number of other design variations can also be explored to enhance the efficacy of demand charges, including:

Greater segmentation in customer classes: Rather than lumping all residential customers into a single pool, customer classes could be separately established for groups such as single-family detached housing, multifamily detached housing and apartment residences, based on the specific investment required by the utility. Because the infrastructure needed to serve these customers may differ, in some circumstances it may be appropriate to capture and charge costs in this differential manner, more appropriately aligning with principles of cost causation. It is the AMI infrastructure and smart technologies that enable this more granular approach.

Changing the definition of demand charges: Currently, most demand charges in the industry/commercial sectors are based on a 15-minute or single-hour NCP approach, in which a user's 15-minute or single hour of peak consumption determines the overall charge. If warranted by policy or regulatory goals, this could be made more nuanced by assessing demand charges during established peak periods, defined by each utility, with the highest probability of coinciding with the local distribution system peak. For a summer peaking utility, this might be weekday summer afternoons and evenings. For a winter peaking utility, it could include winter mornings and evenings. As technology evolves to manage household demand and adjust to these signals in real-time, utilities could even make this distinction on a substation-by-substation basis. Alternatively, some participants supported establishing an on-peak and off-peak demand charge, assuming periods could be established that mitigated any significant revenue erosion.

Other options for demand charge design: There also are multiple options to assess a charge after obtaining the customer's peak demand. In one approach, demand charges are collected for each month of the year. In another, they would only be collected during the peak season based on the customer's monthly peak demand. This second approach will concentrate the recovery of demand costs into fewer billing cycles, sending a stronger price signal to customers to manage their peak demands. On the other hand, it may reduce revenue stability and may be misaligned with principles of cost causation. In a third approach, the seasonal average would serve as a demand ratchet for that customer for the remainder of the non-peaking months of that year. Rates would be calculated to spread the local distribution costs over the 12-month period, even though the billing demand will be determined by the average during the peak season. This results in lower monthly demand charges, but it will send a weaker price signal to incent changes in customer behaviors. While the seasonal average would be more actionable by the customer, some participants assert that it is not as compelling as the customer's monthly billing demand, since the seasonal approaches limit the period of time in which customers can adjust their behavior.

4.3. VOLUMETRIC CHARGES

For purposes of this transitional rate design, we assume the case that utilities have already implemented AMI and thus can implement sophisticated rates that include dynamic time-varying rates (TVRs). Time of use (TOU) rates are one type of TVR and have been used in the past with simple analog interval meters. However, AMI enables more advanced rates that are not fixed based on the meter's predetermined settings, but can be dynamically adjusted to market conditions.

TVR in this proposal is suggested to capture the balance of distribution costs not collected through the customer charge or the demand charge, that otherwise would be incorporated into fixed charges or flat volumetric charges in a traditional two-part rate. This modified three-part rate approach will enhance encouragement of energy efficiency and demand side management, by preserving customers' ability to control their bills through conservation and demand response. The TVR component includes distribution assets from the local substation up through the transmission substations and transmission system, as well as generation costs for vertically integrated (VI) utilities. These costs are further allocated into rates for predetermined off-peak, intermediate and peak periods.

The off-peak period rate would be set to collect a sizable portion of the remaining distribution costs and for vertically-integrated utilities, all baseload generation costs (including return on assets and variable O&M costs such as fuel). It also would be used to recover other utility costs such as depreciation expense, taxes and certain non-generation O&M services.

The intermediate period would collect mid-merit generation costs (the generators that meet incremental load after baseload generators and before peaking generators), as well as any fuel costs associated with running those facilities. Further, it would collect another fraction of the remaining distribution grid costs. These costs would be added to the off-peak rate to establish the total intermediate period rate.

Finally, the peak generation assets and variable O&M costs would be collected into the peak period, along with the remainder of the distribution system costs. These costs would be added to the intermediate period rate to establish the total peak period rate.

The specific times of these three periods can shift based on the season. For a strongly summer peaking utility, it might be appropriate to only have a peak period during summer months and to extend the hours of intermediate and off-peak periods for the non-summer months to increase the intensity of the cost-causation price signal.

4.4. CRITICAL PEAK PRICING

While the volumetric prices above are primarily intended to recover the costs of existing utility assets and other utility expenses, it is also important to send a forward-looking price signal to avoid the need for costly, infrequently used assets. Critical peak pricing (CPP) serves this purpose and some participants have posited that CPP can be used in conjunction with or as an alternative to TOU pricing for generation. The price would be set based on the cost of building and recovering costs of incremental assets over a small number of hours. It is likely – and in fact maximally effective – that this price will be many times larger than even the peak-period rate. Sending a strong price signal to discourage incremental load during times of extremely heavy grid use encourages customers to respond by reducing the load, thus eliminating or delaying the need to procure or construct incremental supply and distribution equipment.

Since the utility cannot know in advance how often CPP events will be called by system operators, revenue from this bucket will always be somewhat variable and therefore should not be relied upon to recover costs of operating and maintaining a safe, reliable power grid. Since these revenues cannot be relied upon to recover costs of operating the grid, they should be utilized for the direct long-term benefit of customers. For example, revenue collected during CPP events could be used to fund customer energy efficiency or demand response programs. Alternatively, it could be used to reduce the off-peak rate in a following year.

4.5. CARBON PRICING

Decarbonization is a key requirement for the modern grid. Like other desired impacts of rate design, the impacts of rate design on system emissions is highly complex and dependent on context and implementation. The most direct path to ensure movement toward a decarbonized grid is to include a price on carbon as a component of volumetric rates, thus sending a clear price signal that values decarbonization.

One of the core principles of RDI was to create rates that send proper price signals to customers for increased system energy efficiency and encourage DSM for customers to control their bills, balancing societal, individual, and utility interests. Accordingly, the management of total energy – not just peak demand – remains important and is consistent with the core principles. Setting a value on carbon is external to energy prices, yet no less important in creating that balance. While the Alliance is on record in support of some form of a carbon price, we are agnostic to the specific form of implementation. That said, the Alliance believes that a national carbon policy is preferable to regional or state policies and that it should recognize existing regional and state programs.

The modern grid of the future assumes universal deployment of AMI and broad deployment of home and business automation that seamlessly integrates demand-side resources.

5

IMPLEMENTING A TRANSITIONAL RATE DESIGN

Some of the components of the rate design scenario discussed above are already in use today, but others are not. Demand charges for mass-market customers are very rare and when used, are almost entirely voluntary. TVR is more prevalent, but most often remains an opt-in rate design. Critical peak pricing, typically in the form of a critical peak rebate, is being implemented in several jurisdictions, as is carbon pricing, although such policy is currently limited to regional or state-based approaches. However, the feedback the Alliance received from the RDI participants is that today's rate design will not assist us in transitioning to the modern grid. New rate designs will be necessary.

5.1. KEY DISTINCTIONS BETWEEN THE STATUS QUO AND A TRANSITIONAL RATE DESIGN

The modern grid assumes universal deployment of AMI and broad deployment of home and business automation that seamlessly integrates demand-side resources. The proposed transitional rate design to enable this grid relies on AMI as a first step. While AMI has been installed for roughly 50% of all utility customers, many utilities currently have no plans to roll out smart meters. In fact, according to an Alliance analysis of 2014 EIA data, 58% of utilities had zero AMI meters deployed, while 30% had AMI installed in at least 98% of their customers premises.[9] In other words, it is currently an all-or-nothing approach and average AMI deployment figures are being skewed upward by large IOUs that are fully implementing AMI.

RDI core participants advised the Alliance that the additional capabilities that AMI provides for load management and rate design warranted its deployment where cost-effective. As complexity and interconnectedness grow, having AMI capabilities will be increasingly important to manage the electricity grid. To realize the Alliance's transitional scenario, AMI is likely required.

Home and business automation products are rapidly emerging. Companies such as Nest, Amazon, Samsung and Verizon have more recently entered this space, along with more traditional providers such as Whirlpool, Ingersoll Rand, Johnson Controls and Schneider Electric. Although it is possible for customers today to install home automation systems, the markets and services needed to fully utilize them are still emerging. This is a very active space and progress continues to accelerate.

Customer charges are very common today, found in over 90% of IOU tariffs and over 80% of municipal and cooperative tariffs.[10] Thirty-two states include a fixed customer charge on 100% of the residential tariffs. However, the fixed charge does not always recover the full customer-specific costs.

The most prominent example is in California, where until recently there was a *de minimus* customer charge for some utilities and no minimum bill. Recent actions by the CPUC implemented a $10/month minimum fee ($5/month for low-income customers) that will recover some of the costs from each utility customer regardless of usage.

In other jurisdictions, the fixed charge recovers not only the customer-specific costs, but also some "minimum system" costs.[11] In the past several years, some utilities have filed for increases in their customer charge to recover more of these minimum system costs. [12]

Demand charges remain uncommon in the mass market, but proposals for their use continue to arise. AMI is a prerequisite for mass-market demand charges,[13] and as discussed above, roughly half of household meters were still using traditional analog meters as of the end of 2015.[14] In utilities that have implemented demand charges, nearly all are voluntary (19 utilities in 14 states). A handful of utilities are requesting mandatory mass-market demand rates in their current rate cases (Arizona Public Service and Gulf Power are two recent examples).

Volumetric rates today are primarily flat, with some utilities implementing seasonal and tiered rates. As discussed above, as MWh sales remain flat or decline, recovery of fixed costs from existing utility assets through flat volumetric pricing is increasingly challenging to maintain a reliable, cost-effective and affordable system. That said, temporal price signals (such as seasonal rates that are higher in months that correspond to system peaks) should still be implemented. Additionally, tiered rates such as inclining block structures where the volumetric price increases after a certain quantity of kWh is used, can send a stronger energy efficiency signal.

TVR and TOU rates have been around for decades. TOU has been implemented by utilities for mass-market customers going back to the 1980s, although fewer customers are on TOU rates now than in past years. TOU rates are designed to increase economic efficiency, as they better send price signals that correlate with supply costs. TOU rates can be implemented on some traditional meters that are capable of recording usage during pre-determined time periods. For non-AMI utilities that have these meters, there could be benefits in developing simple TOU rates. As jurisdictions continue to evolve to AMI, the Alliance believes that static TOU rates will become less effective, as they lack the flexibility to quickly respond to evolving market conditions.

As a first step in our proposed transitional rate design, we assume advanced metering and home automation technology will be implemented to dynamically respond to price signals. And those price signals would contain the costs and benefits of using or supplying energy during each period. This dynamic capability is important as a static TOU design might be overcome by events as technology and usage patterns shift.

Critical peak pricing is currently being implemented in some form in many states. In some jurisdictions, utilities offer a critical peak rebate (CPR) for customers who reduce their usage during peak events.[15] This rebate can provide a strong signal to customers to ease congestion on the grid. In contrast to CPP, CPR must first determine the baseline usage of a customer, which can introduce some uncertainty in providing the correct amount of rebate.[16]

Our transitional rate design suggests a forward-looking CPP rate that would reduce these concerns by sending clearer price signals about the price of developing incremental assets that operate very infrequently (less than a few dozen hours per year).

Carbon pricing exists now for 40 national and 24 sub-national regions in the world.[17] In the U.S., California and the nine states[18] in the Regional Greenhouse Gas Initiative (RGGI) have implemented some form of carbon pricing. Many private companies implement internal "shadow" carbon pricing to help inform management and investment decisions.[19] To most cost-effectively realize decarbonization in the modern grid, the Alliance recommends a carbon price implemented at the national level, compatible with existing efforts. The Alliance is neutral on what form of carbon pricing is implemented, whether a carbon tax, a market-based mechanism or some other form.

We recognize that a national system that fully captures the externalities of greenhouse gas emissions and prices them into energy costs is not likely in the near term. However, this policy will be an important component of rate design to reach the decarbonization described in the modern grid.

When considering practical advances in rate design, we must consider what is feasible in the near future both from a technology and a regulatory perspective.

6

THE REALITIES OF MOVING RATE DESIGN FORWARD

Having discussed where we want rate design to go in the next 3-5 years and where it is today, how do we get from here to there? This complex question provoked multiple responses from the RDI participants, but we found clear consensus on this point: there is no single path that can be pursued by all utilities to reach the same outcome.

Rate regulation is an inherently local issue. While state commissions set rates for most investor-owned utilities (IOUs) and some larger municipal utilities or rural cooperatives, many rural cooperatives and municipal utilities set their own rates. Rate design must consider the technological starting point of the utility; as illustrated earlier, AMI deployment is currently very binary (it is either fully implemented, or not at all) and much more prevalent among IOUs than cooperatives and municipal utilities. Some states have policies such as energy efficiency resource standards (EERs) and revenue decoupling that provide incentives for energy efficiency and demand response deployment, while others do not.

These and other issues of local control over rate setting are very important to stakeholders. As a result, some utilities will be able to start the process to implement our proposed rate design immediately while others will have to go through further transitional changes. And in some instances, there may be circumstances that prevent certain types of utilities from fully implementing the recommendations in this document. We point this out not to critique the different choices made by states, but simply to point out that this is the reality that regulators face when they contemplate rate design changes.

Given that the transitional rate design requires AMI to be successfully implemented, we define at least two different starting points: utilities with AMI and utilities without AMI. The first step would be to tell all utilities to immediately implement AMI and move forward from there, but that is neither likely nor productive. The Institute for Electric Innovation's report on smart grid deployment projects 90 million AMI meters by 2020, up from roughly 60 million today.[20] This improvement will only represent about two-thirds of household meters, meaning that tens of millions of customers still will not have AMI in the near future. It therefore is appropriate to discuss rate designs that utilities may implement without AMI, while still encouraging utilities to implement AMI when and where it is cost effective.

Another key component of the transitional rate design is an assumption that there are advanced automation software and services available widely that are capable of responding to electronic signals in real time and controlling major household and commercial appliances and equipment. Given the rapid development of these technologies in the past few years, it is not unreasonable to assume broad deployment at some point in the near future. As with AMI, we cannot take for granted that this technology – and the necessary modifications to markets and policies – will be seamlessly integrated in the immediate future. Below, we discuss some steps that utilities can take today to move toward the transitional rate design as technology and markets develop, including conducting more real-world pilots and analysis.

When considering practical advances in rate design, we must consider what is feasible in the near future both from a technology and a regulatory perspective. This section will discuss options for utilities with AMI and those without, and suggesting specific steps that all utilities and stakeholders can take to develop supporting technologies and policies needed to attain the transitional rate design.

6.1. NEAR-TERM RATE DESIGN FOR UTILITIES WITHOUT AMI

Dynamic TVR, demand rates for mass-market customers and critical peak pricing all require AMI. However, there are still several rate designs that can be implemented that will encourage energy efficiency, better align utility costs with customer rates and improve system energy efficiency of the grid even in the absence of AMI.

In each of these cases, the utility and state regulators should consider the bill impact from the rate design change. The examples below are intended to represent a starting point for the rate design and it is anticipated that commissions, utilities and stakeholders would go through an iterative process to ensure that any change does not induce rate shock. If the changes are larger than stakeholders are comfortable with, they can be phased in over a period of time.

Three examples are discussed below, in decreasing order of economic efficiency. Consistent with the principles and objectives of the RDI, the Alliance recommends TOU rates with a seasonal design element for those jurisdictions without AMI.

6.1.1. TOU RATE DESIGN

In TOU billing, fixed periods of hours are separately logged by the meter and billed based on different rates. These periods typically correspond to peak, intermediate and off-peak hours. A TOU rate should still have a customer charge that recovers customer costs, while all remaining costs are recovered through the different periods on a volumetric basis.

TOU rates increase economic efficiency as they can signal prices correlating with supply costs. At off-peak times, when energy is typically less expensive, rates are low. During peak times when high-cost assets are needed to meet demand, rates are higher. TOU rates can also be designed to allocate demand-based distribution systems costs into the peak and intermediate period volumetric rate.

A key characteristic of a TOU rate is the peak/off-peak period ratio. The higher the ratio, the more incentive a customer has to shift usage. Nearly 60% of residential TOU tariffs had a peak/off-peak ratio of less than two, while more than 20% had a ratio of three or higher.[21] In these higher ratio tariffs, a customer is receiving a stronger signal to shift their usage and substantial bill savings could be realized if they are able to change their behavior. Additionally, by better managing their usage during peak periods, system efficiency can be improved.

The core RDI participants generally agreed that TOU rate design could be a useful tool to implement the rate design principles in certain circumstances. Peak period volumetric rates could capture some portion of the demand-based costs from the distribution systems and generation facilities. Fuel costs can be allocated to different time periods as less fuel-efficient generation facilities are often used at peak times and require more fuel (and thus more costs) to produce each MWh of electricity.

TOU rates can be combined with tiered and/or seasonal rates. One must be careful not to get overly complex, but it is possible (and implemented by some utilities) to have tiered, TOU rate designs that vary by season. We acknowledge commissions' common requirement to design rates that are transparent to consumers, keeping rates as simple as possible while still sending appropriate price signals, particularly when combining seasonal rates with other rate design types. In their efforts to improve the economic efficiency of the system and fairness within and between customer classes, this can sometimes be a difficult balance, which we believe can be accomplished through customer education and enabling energy management tools.

The table below, as well as those that follow, illustrate how costs might be allocated to different rate design charges in a non-AMI jurisdiction. The percentages are illustrative and not meant to be prescriptive. Should a similar rate design be adopted, appropriate percentages would best be determined in individual proceedings.

TIME OF USE RATE DESIGN COMPONENTS	NOTES
Customer Charge ($)	Includes all customer-related costs necessary to connect to grid
Off-Peak Period Rate ($/kWh)	Includes • 100% of other expenses (G&A, non-generation O&M, etc) • 60% of return on demand-based distribution assets • 100% of return on baseload generation assets* • 100% of baseload generation fuel and O&M
Intermediate Period Rate ($/kWh)	Off-peak rate, plus adder for • 20% of return on demand-based distribution assets • 100% of return on mid-merit generation assets* • 100% of mid-merit generation fuel and O&M
Peak Period Rate ($/kWh)	Off-peak rate, plus adder for • 20% of return on demand-based distribution assets • 100% of return on peak generation assets* • 100% of peak generation fuel and O&M

** Indicates costs for vertically integrated utilities. Illustrative purposes only.*

In discussions with the Alliance, the RDI core participants observed that TOU rates are inflexible in the face of the changing utility landscape and the Alliance concurs. With customer usage patterns shifting because of DSM and DG, in some locations peak and off-peak periods have shifted already and will be different still in the future. The prototypical example of this phenomenon is the California "duck curve" and its mid-day net load shift due to increasing deployment of solar PV.[22] Changing TOU periods would require physical modifications to analog meters and re-educating customers. Additionally, the RDI group did not feel that installing analog TOU meters was a worthwhile investment for utilities that did not already have that capability, as it would be an expensive proposition with limited cost-effectiveness potential. It was considered a more prudent investment decision instead to move directly toward deploying AMI in order to enable the modern grid.

6.1.2. SEASONAL RATE DESIGN

Seasonal rates vary based on the time of year and are a simple way to allocate certain demand-related costs to volumetric rates. For a utility that peaks during the summer, the utility could make volumetric rates in the summer higher than those in winter, to capture the capacity costs associated with serving peak load.

Although less economically efficient than TOU rates, this design is easily understood by and transparent to customers. Seasonal rates can also be combined with tiered rate designs to send a stronger price signal to customers.

SEASONAL RATE DESIGN COMPONENTS	NOTES
Customer Charge ($)	Includes all customer-related costs needed to connect to grid
Non-Peak Seasonal Rate ($/kWh)	Includes • 100% of other expenses (G&A, non-generation O&M, etc.) • 60% of return on demand-based distribution assets • 100% of return on baseload generation assets* • 100% of baseload generation fuel and O&M • 50% of return on mid-merit generation assets* • 50% of mid-merit generation fuel and O&M
Peak Seasonal Rate ($/kWh)	Non-peak season rate, plus adder for • 40% of demand-based distribution costs • 50% of return on mid-merit generation assets* • 50% of mid-merit generation fuel and O&M • 100% of return on peak generation facilities* • 100% of peak generation fuel and O&M

** Indicates costs for vertically integrated utilities. Percentages are intended to be illustrative.*

6.1.3. TIERED RATE DESIGN

Non-AMI utilities could implement tiered, or block rate designs. These rate designs charge one rate for an initial quantity of energy use and a separate rate for additional use. Rates can either increase (inclining block) or decrease (declining block) as a customer uses additional kWh.

From an energy efficiency perspective, inclining block structures are more conducive to sending price signals to reduce energy use. However, as seen in certain locations such as California, very steep block rates can result in unintended consequences for revenue recovery and unintended cost shifting between consumers. A more conservative inclining block structure can be used to recover additional capacity costs from high electricity users, whose total energy use tends to correlate more with higher peak energy use. The first block could be set at a modest level, such as 150% of median energy use, to ensure that the bulk of the incremental cost recovery falls to the heavier users of the system. However this is allocated, the Alliance believes that block rates should principally be correlated to costs.

INCLINING BLOCK RATE DESIGN COMPONENTS	NOTES
Customer Charge ($)	Includes all customer-related costs needed to connect to grid
Base Rate ($/kWh)	Includes • 100% of other expenses (G&A, non-generation O&M, etc.) • 60% of return on demand-based distribution assets • 100% of return on baseload generation assets * • 100% of baseload generation fuel and O&M • 50% of return on mid-merit generation assets* • 50% of mid-merit generation fuel and O&M • 50% of return on peak generation facilities* • 50% of peak generation fuel and O&M
Block 1 Rate ($/kWh)	Base rate, plus adder for • 40% of demand-based distribution costs • 50% of return on mid-merit generation assets* • 50% of mid-merit generation fuel and O&M • 50% of return on peak generation facilities* • 50% of peak generation fuel and O&M

** Indicates costs for vertically integrated utilities. Percentages are intended to be illustrative.*

6.1.4. MAXIMIZING IMPACTS FOR NON-AMI UTILITY RATE DESIGN

The Alliance recommends that non-AMI utilities implement seasonal TOU rates. For utilities with metering capable of implementing seasonal TOU rates, this represents the best balance between encouraging demand-side energy efficiency and system energy efficiency.

Seasonal TOU rates are a preferred option where available as they enable a tighter targeting of demand-based costs to those customers who are using the system at peak times. Capacity costs can be concentrated in peak rates during the peak season months, sending a strong signal for customers to manage their coincident peak loads. This will help reduce future system costs and it will increase the overall system energy efficiency of the grid. Utilities can anticipate some degree of peak shifting in response to these price signals and design the TOU period rates accordingly.

For those without the capability to implement seasonal TOU rates, tiered, seasonal rates are superior to flat volumetric rates in two ways. First, they more accurately assign demand-based costs to the time of year when those costs are incurred. Second, tiered rates allow utilities to take advantage of the correlation between total energy use and peak demand, to more accurately assign peak demand costs to customers likely to be using the system during peak times.

These rate designs will encourage both overall energy efficiency as well as peak demand reduction, increasing overall system efficiency. Customer education will be required in both scenarios, but should be more moderate for the tiered, seasonal rate than for the seasonal TOU rate.

Even as non-AMI utilities transition from flat, volumetric pricing to something more aligned with system costs, the RDI core participants strongly recommend they consider implementing AMI. As customers continue to want more from their energy providers and as technology evolves to offer opportunities to better manage use and costs, AMI will become increasingly indispensable. AMI may not be cost-effective for every utility to deploy immediately, but an eye should be kept towards future benefits as they develop.

6.2. TRANSITIONAL RATE DESIGN FOR UTILITIES WITH AMI

The transitional rate design for utilities with AMI in the near term (including piloting studies) includes both new and familiar components: a customer charge, a demand charge, a TVR energy charge, a critical peak price and a carbon price. The path toward the transitional rate design is, at the same time, more straightforward and more complex for utilities that already have AMI. While one of the major technical hurdles (AMI deployment) has already been cleared, the transition to mass-market demand charges presents complexities beyond the technical. To that end, we advise here the steps that stakeholders can take to help them move toward the end goal. Ultimately, the pace and path that utilities take to implement the transitional rate design will depend largely on state commissions and stakeholders. But the Alliance believes that the shifts in rate design will be critical to increase demand flexibility, increase system energy efficiency and decarbonize the energy sector.

6.2.1. IMMEDIATE CHALLENGES

AMI customers might already have been exposed to CPP in some form (such as the peak time rebate discussed above) and TVR is comparable to TOU rates that are based on the traditional kWh. However, demand charges, especially, may be new to customers and significant outreach and education, coupled with appropriate incentives to adopt technologies to manage response will be necessary. Non-AMI customers are likely better equipped to immediately understand tiered, seasonal and TOU rates as they share a fundamental characteristic – billing based on kWh usage – with the current flat volumetric rates.

Because demand charges are less familiar to most mass-market customers, the modern grid assumes that technology exists to manage home and business energy use. After all, if one can coordinate the cycling of an air conditioner with that of the washing machine and oven, one can run all simultaneously without a significant spike in power. But it should be said that this automation is not necessarily required to begin the transition.

These challenges can and must be overcome to reach the future scenario where demand charges send needed price signals to the market and customers are able to manage their costs. The sequencing of rate design changes in the near-term will be critical to successfully implement new rate designs in the future, while ensuring that customers – and eventually automated home management systems – are able to react to the price signals. We discuss below a potential path from the current state to the transitional rate design, recognizing that each utility and commission will proceed at their own timing and based on their own precedent. By moving quickly in some areas and incrementally in others, the proposed transitional rate design can be reached in relatively short order.

6.2.2. INITIAL STEPS – ANALYSIS AND PILOT PROGRAMS

Our intention here is to lay out the full recommended process where all steps can be executed in a public stakeholder process. Some utilities have already performed some of these steps, in which case they may move forward to subsequent activities.

Analyze system use. One of the first steps on this path is to analyze the system to characterize and segment customer usage and demand and present the findings. Where accessible, information such as distribution of total usage, CP demand, utility CP demand, feeder CP demand and NCP demand should be included. For residential customers, information should be broken out by different characteristics that may impact system usage, such as apartment, multifamily and single family detached housing stock.

Next, as a first step to educate consumers as to the need for rate design transition, cost and revenue allocation can be compared between current and proposed rate structures and the impact on various customer types can be analyzed.

Develop pilots. Consistent with the regulatory principles of gradualism, the Alliance recommends that the utility propose a pilot program with input from stakeholders that will incorporate elements of the future rate design scenario such as demand charges and dynamic TVR. The pilot could be designed to encompass geographically contiguous areas so that the impact on local distribution equipment can be measured. Utilities might provide some customers with supporting technology, such as home automation equipment or in-house displays. Shadow pricing will be a critical component of these pilots, with customers seeing their bills based on both current and multiple new rate designs (for instance, different versions of TVR along with different demand charge structures such as a single 60-minute NCP demand, a monthly average NCP demand, a monthly average NCP demand during peak hours and a season-long average NCP demand during peak hours).

An optimal pilot should draw real-world conclusions on the efficacy of the home automation technology and how customers respond to new rate designs. It also will be critical to track and analyze detailed data about local distribution circuits, including loads during peak and off peak periods, as well as total energy use over time. Additionally, pilot programs will help utilities and regulators understand how actual utility customers respond to different price signals in a way that theoretical economic analyses cannot.

Rollout of the transitional rate design. After the pilot program is completed and hearings to examine the results and receive stakeholder input have been conducted, results of various rate designs should be considered, including:

- Total energy use and system and feeder peak demand
- Bill impacts on different customer classes and on the continuum of users within a class
- Economic efficiency of rate design and adoption of beneficial efficiency measures
- The effectiveness (or lack thereof) of different in-home technologies for managing customer peaks

Results of the pilot program can be used to design a rate structure that combines the most effective elements and continued education and technology will be necessary to assist customers in understanding how to best manage their usage under the new rate structure before the new rates are implemented system-wide.

This transitional rate design may be implemented in stages, as stakeholders confirm that cross-subsidization is not of issue and vulnerable populations are not disproportionally impacted. For example, by 2015, CPP was implemented for residential customers in twelve states and for commercial and industrial customers in 24 states.[23] Likewise, educating customers on TVR early would give additional time for customers to understand and adjust their energy use behavior. As technology emerges that enables customers to automatically react to and respond to demand-based rates, they can be phased in and be used to collect some portion of demand-based costs. Effectively, this change would affect the individual TVR period rates, but would not change the overall structure of the volumetric portion of the bill.

6.2.3. POLICY CONSIDERATIONS IN IMPLEMENTING A TRANSITIONAL RATE DESIGN

As rates are transitioned to optimize the balance of system and demand side efficiency, complementary policies can help ensure long-term success of these changes. Revenue decoupling could be implemented to balance out the short-term fluctuations in revenue recovery from unanticipated changes in energy sales. Carbon pricing legislation more accurately accounts for currently-externalized costs. Performance-based ratemaking is also a policy that can help align the interests of customers, utilities and other stakeholders. Regulators will also need to consider the impact of making rates voluntary or mandatory and if voluntary, whether to allow opt-in or opt-out. Stakeholders should work to increase the simplicity of customers' bills, even as rates become more complex.

Revenue decoupling is an important policy for many reasons, but the RDI core participants stressed to the Alliance that it should not be viewed as a substitute for good rate design. At its core, revenue decoupling breaks the link between utility sales and revenue. By adjusting rates up or down depending on actual sales, decoupling ensures that the proper revenue will be recovered by utilities. In the short term, this can protect consumers from over-recovery if there is a hot summer and can protect utilities against under-recovery if energy efficiency programs are more effective than anticipated.[24] However, some participants asserted that decoupling removes the financial incentive for utilities to encourage demand-side management programs and others noted that decoupling may cause some customers to pay less than the costs that they incur, while others pay more (a cross-subsidy). The Alliance concludes that, in the long term, revenue decoupling is a necessary, but not sufficient, component of the solution.

Performance-based ratemaking (PBR) is another policy tool that warrants consideration. Rate designs today provide an incentive for utilities to increase assets and sales. As energy efficiency policies have expanded and sales flattened, decoupling emerged as a policy tool to remove the throughput incentive.[25] Today, other metrics such as reliability, carbon intensity, customer service and customer choice are increasingly important to consumers, policymakers and regulators alike. With PBR, commissions can establish targets for a utility that impact its bottom line. Over-perform and a utility could earn a bonus. Under-perform and it would face a penalty. By aligning the incentives of the utility with the policy outcome, as opposed to simply a volumetric throughput, PBR can be a powerful motivator.

Evidence has shown that voluntary rate designs do not always attract high levels of participation.[26] While many residential customers have access to more complex TOU rates, very few choose them. Likewise, with utilities that have implemented voluntary demand charges, participation is quite low. Voluntary rates suffer from adverse selection issues – those likely to opt into them are necessarily the ones who will benefit. One option is to make the more sophisticated rates we discuss here the default option, but still enable customers to opt out to a more conventional rate. This will dampen the political challenges associated with mandatory rate designs and will likely result in much higher participation in the new rates than if they were voluntary and opt-in.

Many of the options discussed in this document result in rates that are more complex than the traditional two-part rate with flat volumetric pricing. While the Alliance believes that rates must be actionable and as straightforward as reasonable, complexity is not a problem in and of itself, as long as the customer is able to understand the rates or if enabling technology has been deployed to automate customer responses. Shaping rate design to enable the modern grid may be more complex, but the Alliance believes it is an acceptable tradeoff.

One way to address this complexity is to design simpler customer bills. Instead of listing the many separate charges with technical names, bills should be simplified with basic terminology. A link to a utility tariff page can be provided for those seeking more details on which miscellaneous charges are included. But the basic bill should reinforce the core economic principles of the rate design and emphasize what customers can do to help save them money and reduce stress on the grid.

Subject to the assumptions outlined in this document, including AMI, home energy management deployment and customer education, we provide an example in Appendix B of the modified three-part rate design that satisfies the "North Star" objective of creating a more energy-efficient grid. These figures are based on an actual cost of service study for residential customers of a vertically integrated utility, although certain assumptions were made when insufficient data was available.[27] While this exercise represents a substantial simplification of the actual rate case and rate decision process, it is intended for readers to get a sense of how the options discussed in this paper would translate into rates and give a sense of magnitude for the bill components for peak and off-peak months. Not every utility will have the same mix of assets and expenses, or the same mix of customers and load profiles.

A transitional rate design will not only help us progress toward the future, but also help define it. The sooner we begin down this road, the smoother the transition will be.

7

CONCLUSIONS

Rate design is a critical aspect of moving toward the modern grid: one that achieves greater energy efficiency, while being reliable, resilient, decarbonized, automated, transactive, efficient and equity-driven. In a system with AMI deployed, the Alliance recommends the consideration of a transitional rate design — pending positive results in piloting studies — that includes the following components to move us to this future:

1. Customer charge ($)
2. Demand charge ($/kW)
3. Time varying energy charge ($/kWh)
   - Critical peak price ($/kWh)
   - Carbon price ($/kWh)

For jurisdictions where AMI is not available, there are still options available that can meet the objectives outlined in the Rate Design Initiative. The Alliance recommends a seasonal TOU rate that represents the best balance between encouraging demand-side energy efficiency, system energy efficiency and economic efficiency, as they enable a targeting of demand-based costs to those using the system at peak times. These components include:

1. Customer charge ($)
2. Time of Use charge, varying by season ($/kWh)
   - Carbon price ($/kWh)

Transitioning rate design will require cooperation between all stakeholders. If one designs rates or enacts policies independently and in a vacuum, even the most ideal output could cause unanticipated problems. Rather, rate design should be considered alongside other policy decisions, such as the installation of AMI, the implementation of revenue decoupling, the enactment of programs designed to assist vulnerable populations and a national carbon price. Only by coordinating a policy approach with a responsive but manageable rate design will stakeholders be able to move toward socially optimal outcomes.

Consumers are already becoming accustomed to home management systems such as Google Home and Amazon Alexa. More functionality is being built into these devices and network effects are starting to emerge. Such systems already control lighting, heating, air conditioning and other connected appliances. It is not a stretch to imagine these capabilities being extended further and evolving into a home management system.

Control technology provided by third parties to contribute to the modern grid is evolving just as distributed energy resources and energy storage continue to come into the mainstream. Energy storage could be a true game changer, as costs fall in a similar manner as wind and solar PV. The customer of the future will have options open to them that simply do not exist today and they will likely want to take advantage of these newfound capabilities.

It is important in realizing this future that the tools and incentives be implemented to enable it. A traditional two-part rate with flat volumetric pricing is unlikely to support the activities needed to transition to this modern grid. Certain utilities are in a position today to take steps toward the rate design suggested in this paper. Others must address potential AMI deployment to implement more advanced rate designs, but can still take immediate steps to increase the economic efficiency of their rate designs, to the benefit of all consumers.

As we stated in the introduction, the Alliance has offered ideas on how to move forward with a transitional rate design that will not only help us progress toward the future, but also help define it. The sooner we begin down this road, the smoother the transition will be. We at the Alliance eagerly anticipate meeting the challenges that lie ahead of us and look forward to the potential and promise that awaits.

APPENDIX

APPENDICES

APPENDIX A: A POSTCARD FROM THE MODERN GRID: A DAY IN THE LIFE OF CARLA

It is another hot day in July, the third in a row during the current stretch. The utility has implemented its high load protocol for Carla's portion of the utility territory. The changes actually started earlier in the morning, when Carla's home management system took advantage of the low energy prices from the atypical early-morning winds to pre-cool Carla's house. Given the tight building shell and high-efficiency HVAC system, Carla's house is able to maintain the lower temperature with a minimal amount of additional energy supplied from the mid-day solar peak.

As Carla drives home in her EV, the battery has been fully topped off by the solar panels supplementing her charging station at work. She arrives home and habitually plugs in her car. The smart charging port reads the battery state and having already crunched the weather forecast and knowing Carla's schedule for the upcoming days, decides to flip the car into grid support mode to take advantage of the credits available for grid support services. Other houses and businesses with the requisite technology begin their daily dance to balance their load with the local and regional energy supply, automatically optimizing their use to minimize and flatten the total load on their local substation.

While Carla's house is already a comfortable temperature, not every house has been retrofitted with the latest technology that enabled Carla to pre-cool her house with zero-carbon energy. As such, the local utility still faces a substantial ramp period in the late afternoon when many customers come home from work.

The nearby solar panels are still producing a reasonable amount of energy, but their contribution will be fading soon. In advance of that time, the smart home and building management systems in Carla's neighborhood soak up remaining zero-carbon energy, converting it to thermal energy (such as cooling houses or heating water) and topping off any available battery system.

As the sun goes down, Carla's car battery joins with the myriad air conditioners and appliances in hers and nearby neighborhoods to automatically begin balancing themselves. Carla's high-efficiency air conditioner cycles in sequence with her neighbors' systems, preventing too many from running simultaneously. Electric heat pump water heaters are shut down during the heavy evening hours, their water having been previously heated while the mid-day solar output was at its peak. Low cost lighting and occupancy sensors ensure that vacant rooms and buildings are not lit and commercial buildings begin to cycle down for the night.

Because of the advanced coordination of the various technologies, Carla's utility is able to comfortably manage through the hot evening. The neighborhood peaks were well managed, as was the overall utility system. While the peak demand was high, it was well within the infrastructure limits of the system. Those who contributed to supporting the grid will see a nice credit on their next bill.

APPENDIX B: A TRANSITIONAL RATE DESIGN EXAMPLE

Subject to the assumptions outlined in this document, including AMI, home energy management deployment and customer education, we provide an example of the modified three-part rate design that satisfies the Alliance's "North Star" objective to enhance energy efficiency. These figures are based on an actual cost of service study for residential customers of a vertically integrated utility, although certain assumptions were made when insufficient data was available.[28] While this exercise represents a substantial simplification of the actual rate case and rate decision process, it is intended for readers to get a sense of how the recommendations would translate into rates and give a sense of magnitude for the bill components for peak and off-peak months. Not every utility will have the same mix of assets and expenses, or the same mix of customers and load profiles.

B.1 COST OF SERVICE STUDY

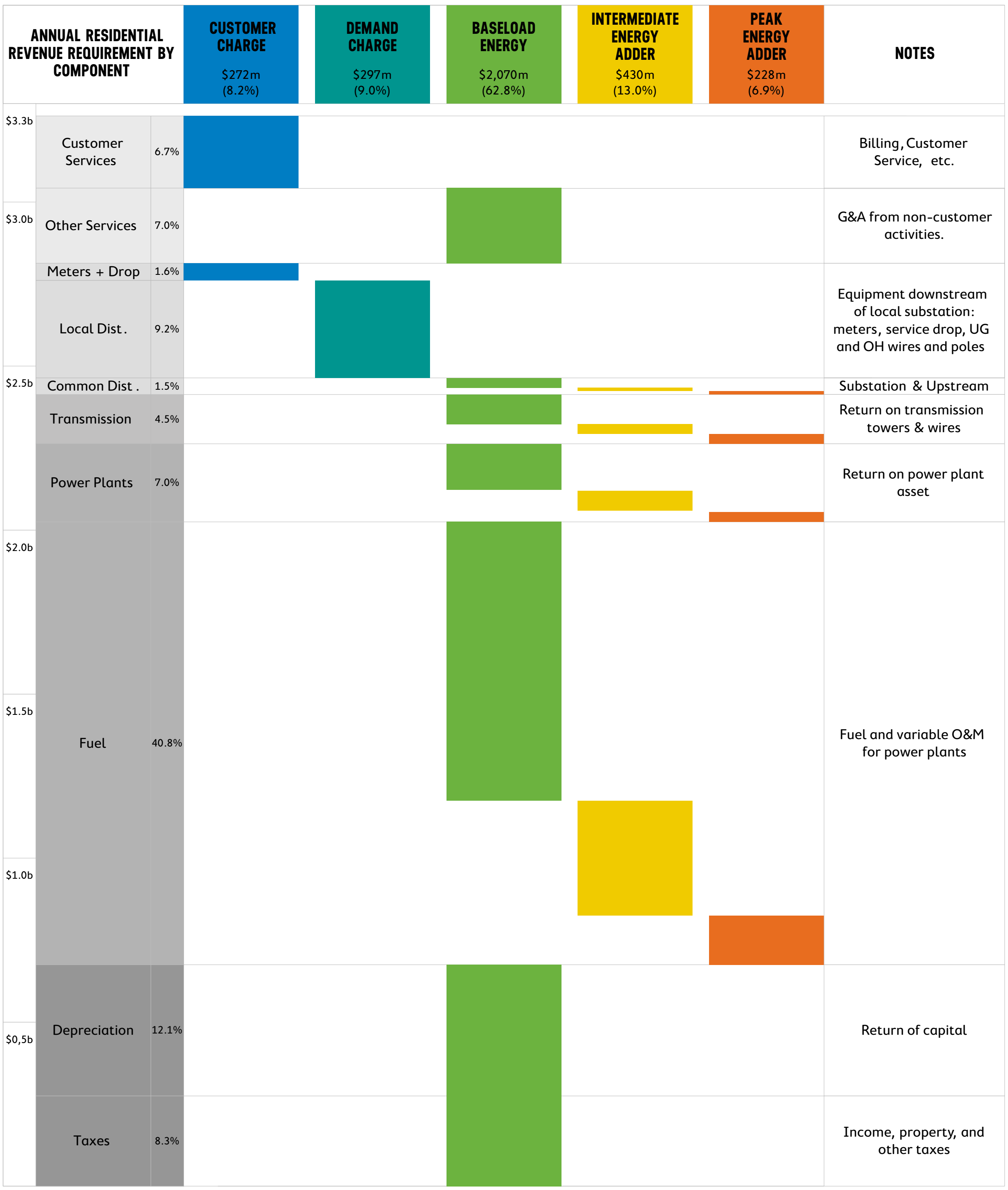
In our example, a vertically-integrated utility has a revenue requirement of roughly $8 billion annually. This figure is based on recovery of all allowable expenses, plus a weighted average cost of capital rate of return of 7% on the utility assets. Once the total revenue requirement has been established, costs are typically allocated to customer classes based on a billing determinant. For example, demand-based costs are allocated based on a customer class's aggregate demand, energy-based costs based on a customer class's total energy sales and customer-specific costs on a per customer basis.

In our example, $3.3 billion in revenue requirement has been allocated to the residential class serving 2,063,000 customers. Fuel costs for the utility's generating assets are the largest single expense, followed by depreciation and return on distribution assets. The table below breaks down the allocated residential class revenue requirement for each category, including both expenses such as fuel and taxes and return on investments. Figures have been rounded for simplicity.

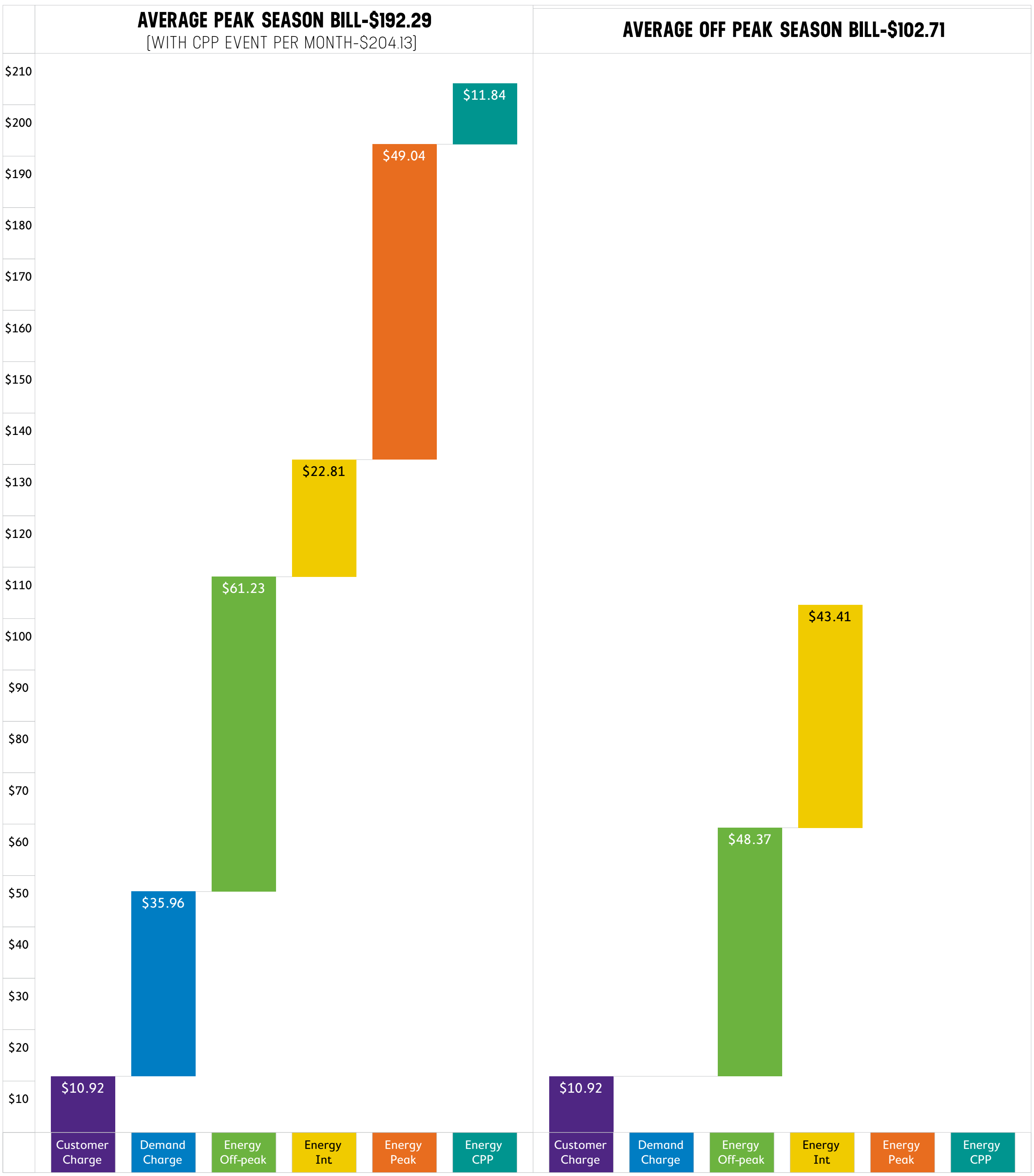
Note: For purposes of this example the costs are broken out by peak, mid-merit and baseload generation plant and variable operation and maintenance (VOM). The Alliance recognizes the recent industry discussions surrounding the usefulness of these specific terms, considering the increasingly prevalent methodology of wholesale generation bids in restructured wholesale markets. However, for purposes of this exercise, we refer to the more traditional accounting method.

ASSET OR EXPENSE CATEGORY	GROSS PLANT	DEPRECIATION	NET PLANT	RETURN	EXPENSE	REVENUE
Generation Plant	6,300,000	2,900,000	3,400,000	238,000		238,000
Peak	750,000	350,000	400,000	28,000		28,000
Mid Merit	1,550,000	700,000	850,000	59,500		59,500
Baseload	4,000,000	1,850,000	2,150,000	150,500		150,500
Generation VOM					1,350,000	1,350,000
Peak					160,000	160,000
Mid Merit					330,000	330,000
Baseload					860,000	860,000
Transmission Towers, Wires and Substation	2,100,000	590,000	1,510,000	105,700	45,000	150,700
Total Distribution	4,850,000	1,350,000	3,500,000	245,000	155,000	400,000
Common Distribution Towers, Wires and Substation	620,000	172,000	448,000	31,360	20,000	51,360
Local Distribution	4,250,000	1,180,000	3,070,000	214,900		214,900
Expenses					135,000	135,000
Substation	45,000	12,000	33,000	2,310		2,310
Poles, wires and conduits	2,285,000	640,000	1,645,000	115,150		115,150
Feeder transformers and distribution automation	80,000	22,000	58,000	4,060		4,060
Customer transformer	810,000	225,000	585,000	40,950		40,950
Customer service drop	810,000	225,000	585,000	40,950		40,950
Customer meter	215,000	60,000	155,000	10,850		10,850
Other Plant	845,000	375,000	470,000	32,900		32,900
Customer services					220,000	220,000
Other Services					230,000	230,000
Depreciation Expense					400,000	400,000
Taxes					275,000	275,000
Total	14,095,000	5,215,000	8,880,000	621,600	2,475,000	3,296,600

Next, we allocate these costs into specific rate design charges. Some of the RDI participants advocated for a more direct translation of cost of service study results into a rate design (i.e. translating all demand costs into a demand charge), while others advocated for an approach that emphasizes factors related to current rate allocation, such as gradualism and unity of earnings. Still others advocated for a policy of no demand charges whatsoever for mass-market customers, based on precedence. As a way forward, which balances the need to encourage demand side management and system energy efficiency, the Alliance recommends the following allocation: customer costs into a customer charge, local distribution (i.e. downstream of the local substation) into demand charges and all the rest into a volumetric three-part TVR structure. A summary is below:



The next chart collapses these costs into the specific rate design categories. For purposes of this example only, we have assumed that demand charges and peak energy charges are collected during the four-month peak period using a CP method. As stated earlier in this report, a non-coincident peak method might also have been assumed if merited in a particular case. The other eight months consist only of the customer charge along with the baseline and intermediate charges. All figures are based on a customer who has an average residential monthly bill of $132.

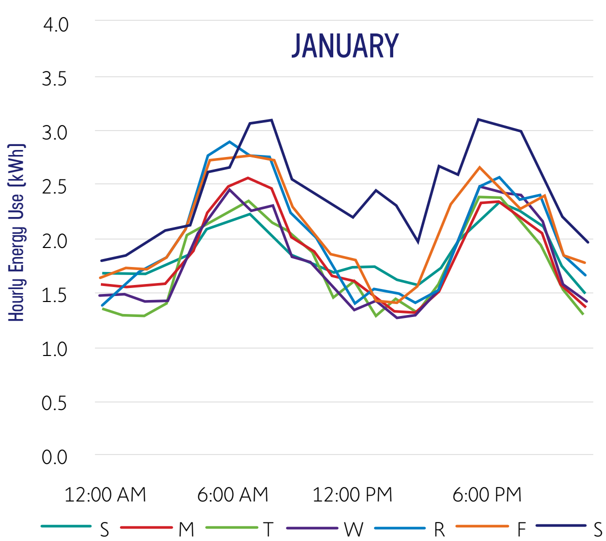


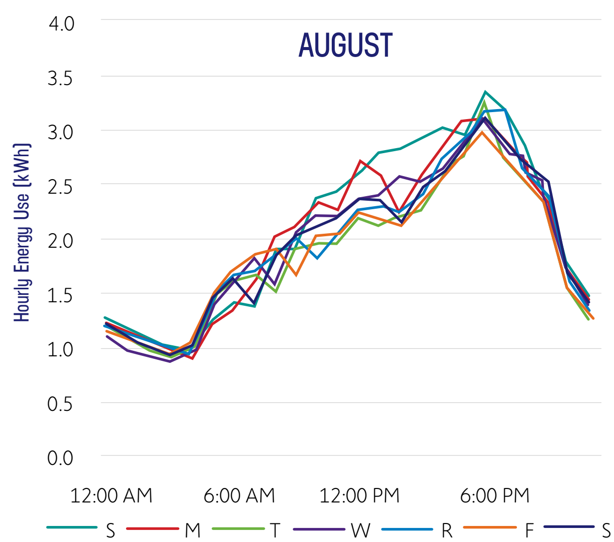
In our example, the bulk of the costs in all months come from the collection of fuel costs, business expenses and return on baseload generation, transmission and common distribution assets that are included in the off peak and intermediate period volumetric charge. Demand charges and peak volumetric charges are reasonably high in the peak months, consisting of 20% and 26% of the bill, respectively. If one CPP event is called each month, it will increase the bill by about 6.5%. However, these categories are not collected at all during the non-peak season months, resulting in a bill that is largely driven by total energy consumption during most of the year. A specific carbon price was not modeled here, but if it were, it would increase the off-peak, intermediate and peak volumetric components according to the carbon intensity of the corresponding generating assets.

B.2 DETERMINING TVR VOLUMETRIC RATES

At this point, we have the total revenue allocated to each component of the bill, along with the average revenue collected for each bill category for a typical customer spending $132 a month. The next step in this process is to determine the actual rates based on the load profile of the customer class. An illustrative unity load profile for a residential customer class was used, scaled to match the annual average residential energy use of the utility of 12,980 kWh per year (an average 1,082 kWh per month).

Usage patterns for residential customers vary by day of the week and by season. Below are average load profiles for January and August. The weekly pattern is clearly discernable in the winter and more muted in the summer. January weekday usage is driven by more customer loads and some heating (the load profile was a blend between electric heating and natural gas heating customers), while August loads are more consistent across the days in response to air conditioning usage.[29]





Each hour in a year was assigned to either the off-peak, intermediate or peak period based on the formulation below, assuming a summer-peaking customer class. In any actual rate design, stakeholders must match peak and intermediate periods to their own usage patterns. Winter peaking utilities (or even winter-peaking classes within utilities) could assign peak costs to winter mornings and evenings and may define different seasons to better link system costs and rate designs. Applying this mapping to the year, 72% of hours (6,307h) become off peak, 23% (2,015h) become intermediate and 5% (438h) become peak hours.

	OFF-PEAK	INTERMEDIATE	PEAK
Summer **(June – September)**	All other hours	Weekdays 1 PM to 3 PM 8 PM to 10 PM	Weekdays 3 PM to 8 PM
Non-Summer (October – May)	All other hours	Weekdays 6 AM to 9 AM 5 PM to 8 PM	None
Total Hours	6,312	2,018	430

In this example, a total of $2.7 billion of the $3.3 billion[30] is collected over roughly 26,500 GWh of sales from just over 2 million customers. When one applies these hours to the collection of costs, an expected pattern emerges. Since proportionally more costs are allocated to peak and intermediate hours and since there are proportionally fewer peak and intermediate hours, peak and intermediate rates are correspondingly higher.

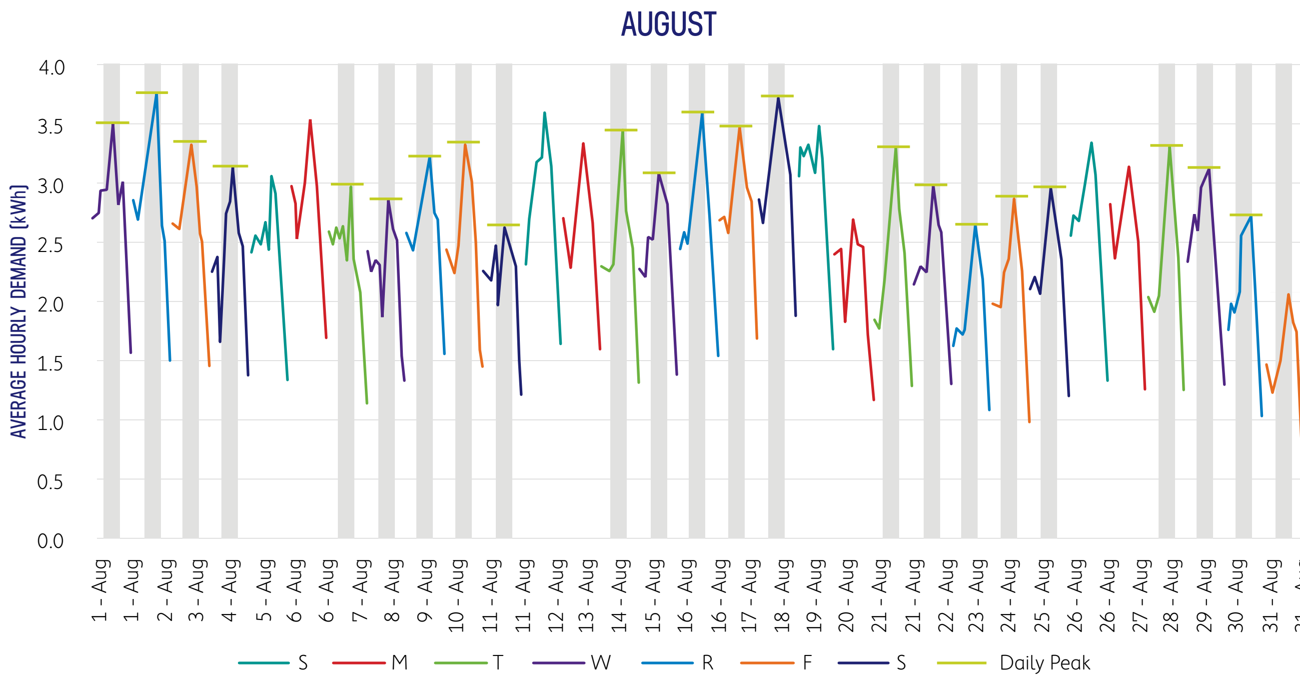
	TOTAL	OFF-PEAK	INTERMEDIATE	PEAK
Cost to Allocate	$2,727,960,000	75.9%	15.8%	8.4%
Energy Sales	26,489 GWh	63.5%	27.9%	8.6%
Period Hours	8,760	72.1% (6307)	23.0% (2015)	4.9% (438)
Average Demand		1.30 kW	1.80 kW	2.60 kW
Allocated Sales and Hours		All	Int. + Peak	Peak only
Period Adder		$0.000	$0.0438	$0.0989
Derived Rate ($/kWh)	$0.1016	$0.0771	$0.1209	$0.2198

The total derived rate reflects a steep TVR structure. Peak price is 2.8 times the off-peak price, resulting from the rate design choices that were made earlier in the example. For instance, peak costs are only collected during the peak season, not year round. Additionally, all fuel costs for and earned return on peak facilities were allocated to these hours. The result reflects the fact that many costs are derived from assets that are infrequently used.

In an actual rate case, an additional step would be performed that would analyze the bill impact on different customers within a customer class. While the data was not available to perform this analysis, it is a critical piece of the rate design process. If this analysis showed that a subset of customers (such as low-use or high-use) are disproportionally bearing the costs of the rate design change, stakeholders would iterate on the assumptions. They could adjust the mapping of the costs to the different billing "buckets" and work toward a design that is more balanced within the customer class. Additionally, they might decide to phase in the changes over time so as to avoid "rate shock" – dramatic changes to customer bills all at once.

B.3 DETERMINING DEMAND RATES

As with the volumetric portion of the bill, the demand costs that have been allocated to the customer must be translated into a charge per kW of demand. In our example, roughly $300m of revenue will be assigned to the demand rate to be collected during the four months of the peak season. For purposes of this example, we take the average of the highest hour-long reading (top of the hour to top of the hour) between 3 PM and 8 PM for each weekday over the course of a single billing period. Below is a graphical representation of the calculation.



In this chart, we see the hourly usage for a typical residential customer between the hours of 12 PM and 12 AM for each day in August. The grey banded areas represent the daily peak window of 3 PM to 8 PM. The dark grey line represents the highest reading for a given single hour within each day's peak window. By our calculation, this customer's monthly demand charge is based on the average of each of the grey line readings, 3.13 kW. Following a similar methodology for the other peak periods, the billing demand would be 3.05 kW for June, 3.21 kW for July and 2.38 for September.

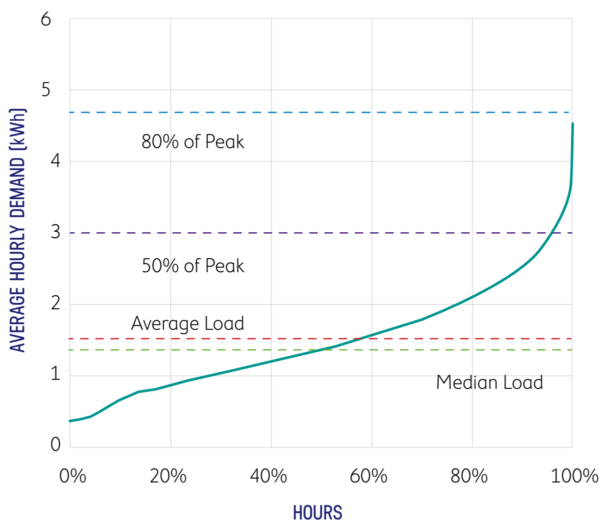
When these billing demands are used to allocate costs solely to the peak summer months, the billing rate can be derived. Based on the total number of customers in this example, we find the following rates and billing results. The demand rate is a function of collecting all demand revenue during the four-month peak season. As discussed earlier, to lower the demand portion of the bill, the total cost ($143.83) could be collected over all twelve months with a demand charge at one third this rate.

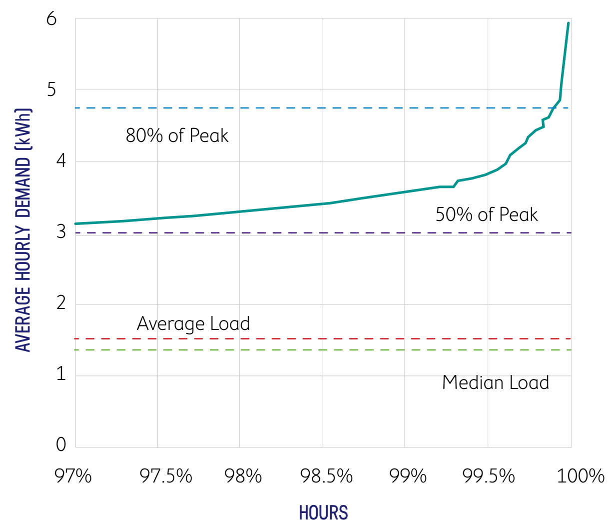
	Total	June	July	August	Sept.
Cost to Allocate	$297,470,000				
Seasonal Billing Demand (kW)	11.77	3.05	3.21	3.13	2.38
Peak Season Demand Rate ($/kW)	$12.22				
Demand Charge ($)	$143.83	$37.27	$39.23	$38.25	$29.08

B.4 DETERMINING CRITICAL PEAK PRICING

The critical peak pricing is the final piece of the rate design example. While the other portions of the bill are designed to collect existing utility costs, the CPP is designed to reflect forward looking marginal costs for new infrastructure requirements. If a utility is faced with load growth or specific locational load pockets, it has two choices to meet demand reliably. One is to build new infrastructure, whether supply, transmission or distribution assets. The other is to proactively manage the load, either reducing it or shifting it to a time where the system is less stressed. Because the new infrastructure will necessarily be a low utilization asset, it will almost certainly be less expensive for customers to avoid or delay building the infrastructure through alternative means.[31]

The Alliance did not have the information needed to calculate this value, but a closer analysis of the typical customer load profile can be useful to illustrate how frequently (or in this case, infrequently) peak assets may be used. Below is a cumulative distribution for the representative load profile.





For this profile, the single highest peak demand is 5.91 kW, but the average and median loads are 1.48 kW and 1.36 kW, respectively. Demand greater than 50% of peak value is only attained for 367 hours, or 4.2% of the time. And 80% of the peak load is only exceeded in 7 hours a year, a mere 0.08% of the time. Taken at face value, this implies that a system built to serve this customer would use 20% of its capacity only 7 hours a year.

Of course, this is just one load profile and individual customers will have different usage profiles. While this fact is unlikely to dramatically affect the distribution of a given customer (they will likely still have steep tails, even if the peak demand is shifted up or down), it will tend to reduce the steepness of the total system distribution profile. And regardless of the steepness of this profile, utilities are obligated to serve all customer demand in a safe and reliable manner. Fortunately, utilities do not build their entire system under the assumption that every single individual customer will peak simultaneously, but rather they build to ensure the class peaks and system peaks can be managed.

Even with this variation among customers, the basic relationship holds true: a non-trivial portion of utility capacity is used as few as dozens of hours a year. If load were to grow, it would require assets that will be used very rarely to meet the incremental demand. From a cost-causation perspective, these assets would have all costs recovered over only a few dozen hours a year and would be very expensive on a per kW or per kWh basis. As an alternative, stakeholders could consider other solutions that would reduce customers' loads. This is the basis for sending a strong price signal through a CPP price.

Since the CPP basis is intended as a signal to induce certain user behaviors that can avoid or delay incremental infrastructure investments, the CPP price should be forward-looking and based on the avoided cost of these new assets when recovered over only a few hours. Given that peak events are not knowable in advance, we do not recommend using the potential revenue to recover historic utility costs. Rather, the revenue collected could be used to support programs that enable customers to better manage their demand or to offset future baseload rates.

Several utilities are currently implementing a CPP tariff. Pacific Gas and Electric has an option residential CPP tariff of $0.60/kWh on peak event days that also reduces the standard peak rate by $0.024/kWh.[32] Minnesota Power ran a CPP pilot with rates in the $0.82/kWh to $0.86/kWh range.[33] Several California utilities run commercial CPP programs with rates in the $1.20/kWh to $1.37/kWh, derived from a cost calculation similar to the one described above.[34] Each of these CPP programs have a strong price signal that is based strongly on cost causation principles.

B.5 PUTTING THE TRANSITIONAL RATE DESIGN TOGETHER

In an actual rate design exercise, consideration is given to balancing inter- and intra-class earnings, avoiding rate shock and applying the principles of gradualism before arriving at a final rate. In our simplified example, these steps are not performed and can be considered a "raw" rate design that serves as the starting point for the next iterations.

The following table summarizes the rate design example, along with the amounts collected in each portion for peak and non-peak average months, representing the average residential customer. Actual results under this tariff will depend on a host of factors regarding an individual customer's usage patterns. The example assumes 4 total CPP events and a CPP rate of $0.75/kWh. Additionally, a carbon price is not modeled in these results, but would have the impact of increasing the TVR rates.

AVERAGE MONTHLY BILL	PEAK SEASON AVERAGE (4 MOS.)			OFF PEAK SEASON AVERAGE (8 MOS.)		
	Rate	**Quantity**	**Bill**	**Rate**	**Quantity**	**Bill**
Customer Charge ($)	$10.92	1	$10.92	$10.92	1	$10.92
Demand Charge ($/kW)	$12.22	2.94 kW	$35.96	$0.00	0 kW	$0.00
TVR Charge ($/kWh)						
Baseload Rate ($/kWh)	$0.0767	798 kWh	$61.23	$0.0767	630 kWh	$48.37
Intermediate Rate ($/kWh)	$0.1209	188 kWh	$22.80	$0.1209	359 kWh	$43.41
Peak Rate ($/kWh)	$0.2198	279 kWh	$61.38	$0.0000	0 kWh	$0.00
CPP Rate ($/kWh)	$0.7500	15.8 kWh	$11.84	$0.0000	0 kWh	$0.00
Total			**$204.13**			**$102.71**

APPENDIX C: ACRONYMS & GLOSSARY

ACRONYMS

AMI	Advanced metering infrastructure
CPP	Critical peak pricing
DER	Distributed energy resources
DG	Distributed generation
DSM	Demand-side management
EE	Energy Efficiency
EERS	Energy Efficiency Resource Standards
EIA	Energy Information Agency
EV	Electric vehicle
G&A	General and Administrative expenses
IOU	Investor-owned utility
kWh	Kilowatt hours
LMP	Locational marginal pricing
NASEO	National Association of State Energy Officials
NARUC	National Association of Regulatory Utility Commissioners
NCP	Non-coincidental peak
O&M	Operation and Maintenance costs
PV	Photovoltaic
RDI	Rate Design Initiative
ROR	Rate of Return
TOU	Time-of-use rates
TVR	Time-varying rates
VI	Vertically-integrated

GLOSSARY

Advanced metering infrastructure (AMI) – an integrated system of smart meters, communications networks and data management systems that enable two-way communication between utilities and customers.

Baseload – the minimum amount of electric power delivered or required over a given period at a steady rate.

Capacity costs – the cost passed on to ratepayers to ensure the utility has secured enough potential generation to meet predicted levels of demand, with a margin of reserve.

Carbon intensity – the amount of greenhouse gases released from combustion of energy production per unit of energy created.

Carbon pricing – a mechanism to limit emissions of greenhouse gases, or their carbon dioxide equivalent (CO^2) by economically internalizing the costs to society in the price of energy.

Coincident peak demand – the energy demand by a customer during periods of peak system demand.

Cost causation – the principle that cost should be borne by those who cause them to be incurred.

Cost recovery – the utilization of a combination of mechanisms by a distribution utility to provide sufficient revenue to provide a return of expenses related to providing electricity service.

Critical peak pricing – when utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during a specified period in which the price for electricity is substantially raised.

Customer/fixed charge – a cost component a customer pays to cover basic administrative costs associated with the customer's account.

Customer class – groupings of customers into categories with similar characteristics (e.g. Residential, commercial, etc.).

Declining block rate – a rate structure that decreases the cost of energy as the customer's consumption increases, typically used by high-volume customers.

Decoupling – policies designed to separate utility profits from total electric or gas sales so utilities do not have an incentive to try to sell more energy.

Default rate – the rate a customer will be charged if a different rate option is not chosen.

Demand – the rate at which electricity is being consumed at a specific time.

Demand charge – a cost component based on the highest capacity a customer required during the given billing period.

Demand response (DR) – a reduction in energy use in response to either system reliability concerns or increased prices or generation costs.

Demand side management (DSM) – programs that plan, implement and monitor activities of electric utilities which are designed to encourage consumers to modify their level and pattern of electricity usage.

Distributed energy resource – a source of electric power that is not directly connected to a bulk power transmission system, including both generators and energy storage technologies.

Dynamic pricing – prices which change due to circumstances, including time-based, seasonal or due to increased demand.

Energy/volumetric charge – a cost component based on energy consumed.

Energy efficiency (EE) – using less energy to provide a given service.

Energy efficiency resource standard (EERS) – a state-level policy that targets reductions in energy use; may be mandatory or voluntary.

Fixed costs – the non-fuel costs incurred by a utility to provide service, typically relating to overhead.

Fixed/ customer charges – charges that appear on every bill every billing cycle, regardless of energy use or demand levels.

Flat rate – a rate design with a uniform price per kWh for all levels of consumption.

General and administrative (G&A) expenses – expenditures related to the day-to-day operations of a utility.

Grid support services – also known as "ancillary services," the services necessary to support the transmission of electric power from seller to purchaser, so that the supply of electricity continually meets demand.

Home automation systems – interconnected equipment and appliances, sensors and controls which can communicate with the grid and other systems to increase energy efficiency while providing desired levels of service.

Inclining block rate – a rate structure that increases the cost of energy as the customer's consumption increases.

Load – the combined demand for electricity placed on the system.

Locational marginal pricing – the way in which wholesale electricity prices reflect the value of power delivery at different locations in different time period, accounting for physical constraints of the system.

Marginal cost – the cost of the next unit of electricity produced.

Mass market – residential and small commercial customers.

Mid-merit – also known as "load following," electric power generation which comes online when demand increases or fluctuates.

Minimum bill – a rate design that charges the customer a minimum utility bill, regardless of how little electricity they use.

Minimum system – the minimum infrastructure that must be in place for a customer to receive electricity.

Non-coincident peak demand – a customer's maximum energy demand during any stated period.

Operation and maintenance (O&M) costs – expenditures related directly to the operation and maintenance activities of the utility.

Opt-in – customers are only placed on an alternative or new rate design if they actively choose that option.

Opt-out – customers are automatically placed on an alternative or new rate schedule unless they actively choose to stay on the old rate design.

Peak demand – the highest demand during a specific period.

Performance-based regulation – sets out specific performance goals and financial incentives to meet the targeted performance.

Rate base – a measure of the total long-term investments made by the utility to serve customers, net of depreciation and other adjustments.

Rate case – a proceeding before regulators that involves the rates to be charged for a service that is provided by a utility.

Rate of return (ROR) – in regulated markets, the rate of return is the revenue allowed to be provided through the utility's rates to incentivize continued shareholder investment, based on the assets the utility owns.

Real-time pricing – pricing rates that apply to usage on an hourly basis.

Restructured market – a utility market in which the historical monopoly system of electric utilities selling the commodity of energy has been replaced with competing sellers; utilities no longer own all levels of the supply chain.

Revenue decoupling – the disassociation of a utility's profits from total electric or gas sales to remove the incentive to sell more units of energy.

Revenue requirement – the amount of money a utility must collect to cover its costs and make a reasonable profit.

Seasonal/monthly demand charges – charges that are based on the highest demand of a customer over a billing period, typically measured in $/kW (but sometimes in $/kVA or $/HP). Seasonal demand charges may include a different demand rate for summer and winter months, while monthly tariffs might vary by month. Additionally, demand tariffs may have different tiers (e.g. one up to 100 kw and another for over 100 kw) with correspondingly different rate levels.

Seasonal/monthly energy charges – charges that are based on a $/kWh rate. As with seasonal or monthly demand charges, these rates may vary season-to-season or month-to-month and may have different tiers with different prices.

Service drops – in the electric grid, the point of electricity delivery from the distribution utility to the customer.

Straight fixed/variable rate – a rate design that recovers all short-run fixed costs in a fixed charge and only short-run variable costs in a per-unit charge.

System efficiency – optimizing the load profile of the electric grid.

Tariffs – fees and charges included in the retail price of delivered electric power.

Time-of-use rates – rates that vary by time of day and day of the week, reflect difference in underlying costs incurred to provide service at different times.

Time of use (TOU) demand charges – charges that are based on the highest demand of a customer over a shorter time frame, analogous to the more common time of use energy rates. In these rates, customers might face one rate during weekday peak hours and another during weekend or off-peak hours. There may also be a seasonal component to the rate levels.

Time of use (TOU) energy charges – charges that are based on a $/kWh rate that vary based on what time of day or week the energy is consumed. The economically efficient use of energy in the economy — e.g., maximizing economic production per unit of energy use.

Vertically integrated market – a utility market in which the utility owns all levels of the supply chain: generation, transmission and distribution; utilities have a monopoly over the production and sale of power.

APPENDIX D: LITERATURE REVIEW & RESOURCES

Discussions with RDI participants (May 12, 2016 – March 15, 2017)

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APPENDIX E: END NOTES

1 Solar Energy Industries Association. n.d. "Solar Industry Data." http://www.seia.org/research-resources/solar-industry-data

2 American Wind Energy Association. n.d. "The Cost of Wind Energy in the U.S." http://www.awea.org/Resources/Content.aspx?ItemNumber=5547

3 For RDI purposes, AMI does not include meters with advance meter reading (AMR) capabilities, but rather those that have full two-way communication with the host utility. While AMR is useful in reducing meter reading costs, it does not include the requisite capabilities to implement advanced rate designs.

4 Participants agreed that the difference between integrated and restructured markets were less impactful in rate design for retail rates and so this paper does not make separate recommendations in these quadrants.

5 Solar Energy Industries Association. n.d. "Solar Industry Data." http://www.seia.org/research-resources/solar-industry-data

6 Department of Energy, Lawrence Berkeley National Laboratory 2014 data.

7 See Appendix D: Literature Review and Resources

8 The proposed rate design is influenced by ***Smart Rate Design for a Smart Future by Jim Lazar and Wilson Gonzalez, Regulatory Assistance Project.***

9 Alliance analysis of EIA Form 861 data

10 All references to tariffs are from the Alliance to Save Energy's analysis of the OpenEI Utility Rate Database (http://en.openei.org/apps/USURDB/), unless otherwise noted. This analysis is available at http://www.ase.org/sites/ase.org/files/rdi_analysis_narrative.pdf.

11 The minimum system approach includes all costs of the distribution network required to deliver the first unit of energy to a customer (such as poles, wires and transformers), even if they are not directly related to the costs of adding an incremental customer.

12 In 2014, 23 cases were filed to recover more customer charges. By September 2015, there were 50 such cases.

13 Commercial and industrial customers might have analog meters capable of measuring demand, but these are almost never deployed to mass-market customers due to their higher costs.

14 Institute for Electric Innovation. October 2016. "Electric Company Smart Meter Deployment. http://www.edisonfoundation.net/iei/publications/Documents/Final%20Electric%20Company%20Smart%20Meter%20Deployments-%20Foundation%20for%20A%20Smart%20Energy%20Grid.pdf

15 One example of a critical peak rebate program is in New Mexico: https://www.pnm.com/peaksaver

16 Some algorithms attempt to factor out weather and occupancy, minimizing the uncertainty.

17 World Bank, Ecofys, and Vivid Economics. 2016. "State and Trends of Carbon Pricing 2016." http://www.ecofys.com/files/files/world-bank-ecofys-vivid-2016-state-trends-carbon-pricing.pdf

18 Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont currently participate in RGGI. New Jersey participated from 2009 to 2011.

19 A list of U.S. companies with internal carbon pricing can be found in the report Embedding a Carbon Price into Business Strategy by CDP, 2016. https://b8f65cb373b1b7b15feb-c70d8ead6ced550b4d987d7c03fcdd1d.ssl.cf3.rackcdn.com/cms/reports/documents/000/001/132/original/CDP_Carbon_Price_report_2016.pdf?1474899276

20 Supra 12

21 Alliance analysis of OpenEI Utility Rate Database

22 St. John, Jeff. November 3, 2016. "The California Duck Curve is Real and Bigger than Expected."

23 Energy Information Administration, Form 861 data

24 While decoupling helps ensure that utilities recover their revenue requirement, it does not address potential intra-class revenue differentials between customers whose relative usage changes as a result of customer action.

25 That is, the incentive for utilities to sell as much energy as possible as their revenues were tied to volumetric sales.

26 A number of strategies to encourage adoption of voluntary rates are included in "Time-Varying and Dynamic Rate Design," RAP, July 2012.

27 For instance, the ratio of baseload, mid-merit and peaking generation assets was estimated based on fuel type and generation fuel costs were prorated based on generation investments.

28 For instance, the ratio of baseload, mid-merit and peaking generation assets was estimated based on fuel type and generation fuel costs were prorated based on generation investments.

29 In another load profile dataset for a different utility but over 8 years, these weekly trends become more clear as single-year variations are averaged out.

30 Note that the costs collected through the customer and demand charges are not included here as they are collected through a different portion of the bill.

31 See, for instance, the Brooklyn Queens Demand Management program: (https://conedbqdmauction.com/)

32 Pacific Gas and Electric. n.d. "Learn About SmartRate". https://www.pge.com/en_US/residential/rate-plans/rate-plan-options/smart-rate-add-on/smart-rate-add-on.page

33 SeventhWave. 2016. "Minnesota Power's Advanced Metering Infrastructure Project." https://energy.gov/sites/prod/files/2017/01/f34/MN_Power_CBP_FinalEvaluationReport_09302016.pdf

34 Nexant. 2016. "2015 Load Impact Evaluation of California's Statewide Nonresidential Critical Peak Pricing Program." http://www.calmac.org/%5C%5C//publications/7._Statewide_2015_CPP_Report.pdf

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