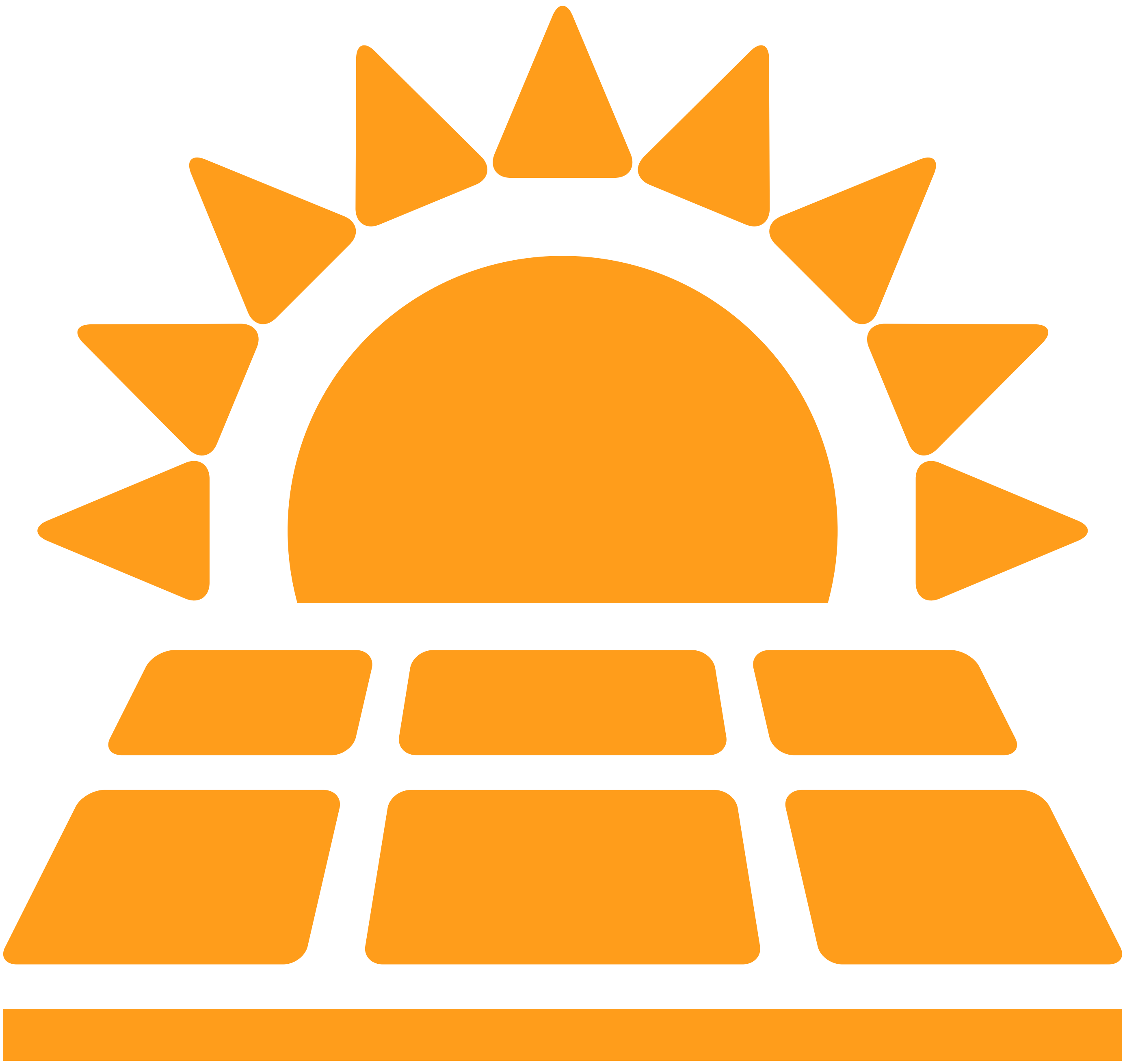
APPA American Public Power Association

APPA's Roadmap to the SEPA 51st State - Phase II



Executive Summary

In response to Phase II of the Solar Electric Power Association's 51st State Initiative, the American Public Power Association (APPA) presents a roadmap for public power grid modernization. APPA has undertaken a strategic initiative titled Public Power Forward which is focused on helping its members prepare for a new era in electricity, to help its members decide whether, when and how to revise their unique rate structures, services and operations to provide the enhanced retail services that their customers want. Distributed Energy Resources (DERs) are a part of that vision.

Profile of Public Power

APPA's submittal begins with a profile of public power utilities in the United States, including utility demographics, their resource portfolios, customer characteristics, services and rate design practices, as well as a description of the public power business model.

Lessons Learned from Electric Restructuring and Characteristics of the Current State

Next, we identify lessons learned from the last round of electric restructuring and characteristics of the current state that will drive the transition to the 51st State for the utility industry. This discussion includes analysis of some of the design flaws that caused electric restructuring to fall short of expectations over the last 20 years, as well as identification of characteristics and starting points for the current transition, including an assessment of current solar and DER penetration and resource costs; tradeoffs between utility, community and rooftop solar; and a discussion of pricing and market design flaws with net energy metering.

First Steps to a Sustainable Future

From the preceding discussion, APPA identifies needed first steps to a sustainable future for public power utilities, including business practice changes, experimentation with community solar, changes to residential rate designs to manage NEM risks, plus community education and governing board support.

Planning the Transition: Developing a Public Power Community Grid Modernization Plan

Finally, APPA outlines how public power utilities could plan the transition to the future state. Public power utilities need to map out and respond to exogenous policy directives and market forces, identify customer and community preferences for new services and then develop a strategy for utility risk management. These change vectors and starting conditions lay the foundation for a public power community grid modernization plan that includes new customer services; third-party business partnerships; advanced resource planning; integration of new resources (including DER) into distribution system modeling, planning and operations; consumer and community education; and changes to rate design and regulatory practices.

Introduction

The American Public Power Association (APPA)[1] is pleased to participate in Phase II of SEPA's 51st State Initiative. APPA learned much from the exchange of ideas in Phase I and looks forward to sharing our thoughts and gaining insights from other participants in Phase II.

SEPA says that: *"The 51st State Initiative can be boiled down to two fundamental goals:*

1. *To create equitable business models and integrated grid structures to ensure that electricity is provided safely, reliably, efficiently, affordably, and cleanly; and,*
2. *To meet customer demand in the near and long term for solar and other distributed options."*

The electric utility industry has often experienced periods in which operating and business practices have been challenged, reconsidered, and sometimes transformed into fundamentally different business and regulatory models. We are unquestionably in such a period now, driven by technological innovation and changing customer preferences. We're driven by new thinking about the relationship among consumers, utilities, and other providers of energy services including distributed energy, storage, customer load management, and energy efficiency. Utilities are also challenged by the financial pressures caused by slow load growth, rapid changes in the relative prices of generation resources, and the pressing need to address climate change and other environmental goals.

APPA members are embracing the emerging trends — but with a public power take. As noted in our Phase I submission, APPA believes that our most efficient path forward is through carefully considered modifications to the public power business model to adapt to structural changes, while ensuring that public power utilities continue to meet customer and community expectations for safe, reliable, clean, and affordable electric services.

Distributed energy resources (DERs) are definitely part of the path forward for public power utilities, but only part of the vision. This new strategic vision is only just starting to emerge.

At the direction of the APPA Board, APPA has undertaken a Strategic Initiative titled *Public Power Forward*, charging APPA staff with helping members prepare for a new era in electricity. APPA will undertake research, advocacy, education, and development of new operational tools and technologies to help our members provide the enhanced retail services that customers want, such as distributed generation (including rooftop and community solar), demand response/energy storage, and energy efficiency.

APPA will also help provide a business, policy, and technology assessment toolbox for members. However, individual members will need to decide whether, when, and how to revise their rate structures, services, and operations — based on the circumstances and opportunities in their states and regions, while ensuring the interests of all customers are protected. APPA's 51st State Phase 2 submission should be viewed in that context.

I. Profile of Public Power: The Current State

Nationwide, there are more than 2,000 public power systems of varying sizes, with diverse service territories, customer bases, resource portfolios, and operational features. Some publicly owned electric utilities generate, transmit, and sell power at wholesale and retail. Others purchase power and distribute it to retail customers. And some perform all or a combination of these functions.

One feature common to all public power utilities — that will continue to be paramount in the future — is the mission to provide reliable and safe electricity service, keeping costs low and predictable for customers, while practicing good environmental stewardship.

SEPA identifies a series of factors or attributes to characterize the current state of the industry. The table to the right presents an overview of the "typical" public power utility.

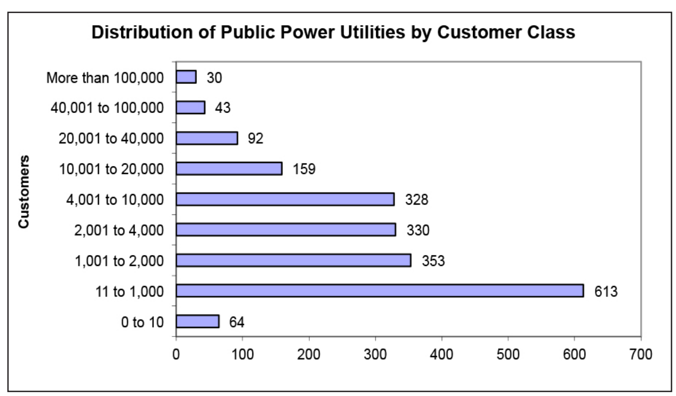
Public Power Current State Descriptors

- **Utility Type –** Public power – state and community owned, not-for-profit distribution utilities
- **Service Territory –** Typically small cities and towns, but also including many large urban centers
- **DER Penetration -** Fairly low but growing rapidly — like much of the nation
- **Utility Structure -** Vertically integrated, with different degrees and varieties of generation ownership and power purchase arrangements
- **Wholesale Market –** Roughly equally divided between RTO/ISO regions and bilateral market regions, with heavy concentrations in regions served by federal utilities
- **Retail Market –** Cost-based, bundled service as opposed to retail competition; most public power utilities are self-regulated
- **Renewable Policy –** State RPS requirements generally apply to public power
- **NEM Policy –** Each utility generally establishes its own NEM policies

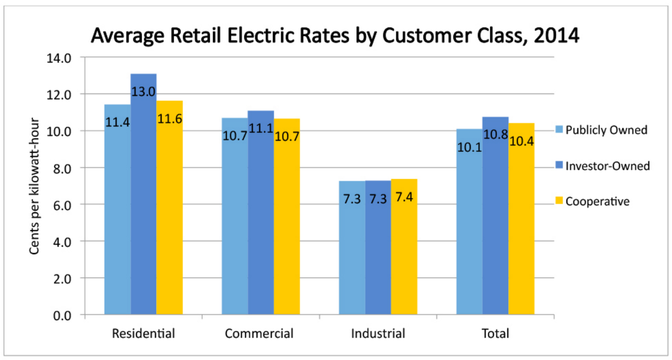
We elaborate on these factors.

A. Demographics

Public power ranges from small utilities serving a handful of customers to large utilities serving large cities with a million or more customers. The typical public power utility, as represented by median customer size, serves approximately 2,000 end-use customers.



On average, public power utilities have residential rates that are approximately ten to fifteen percent lower than those of investor-owned utilities. On average, our service reliability is also well above the national average, as measured by various service interruption and restoration indices.



Source: Energy Information Administration, Form EIA-861, 2014 data.

While public power utilities differ in location and regulatory framework, the typical public power utility is vertically integrated, operates in an RTO market region, and purchases some or all of its power requirements from a wholesale supplier. Over 1,000 of these smaller systems are members of municipal joint action agencies, which are member-owned utilities organized under state law to generate and purchase electricity for resale to distribution utility members. Joint action agencies typically handle interactions with RTO markets on behalf of their members. Many other public power systems are power and transmission customers of large federal utilities such as the Tennessee Valley Authority and Bonneville Power Administration.

The overwhelming majority of public power utilities have independent rate authority, meaning they do not have to obtain state regulatory approval to alter the level or rate design of their retail rate tariffs. These utilities are either governed by the city council or by an independent board that may be appointed or elected. While larger systems tend to be governed by an independent board, the typical utility as described above is more likely to be overseen by the city council, which has final say over changes to rate structures and other utility programs. Utility programs are often used to support broader public policy goals established for the community, such as economic development and support for new businesses.

Public power utilities are closely connected to the communities they serve. Many are operated by a handful of employees that wear other hats for the city government. While public power utilities are generally exempt from state and local taxes, most make substantial contributions to state and local governments through payments in lieu of taxes and other contributions (such as municipal street lighting). Payments in lieu of taxes on average exceed five percent of total revenue.

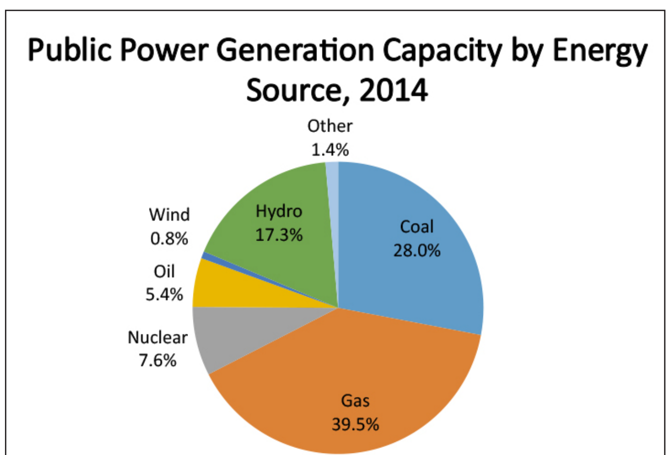
Therefore, even though public power utilities are not for profit, revenue and sales reductions due to increased DER penetration could impact the amount of money they are able to return to local governments.

Public power utilities are largely exempt from regulation by the Federal Energy Regulatory Commission, although they are subject to the rules and regulations established by FERC for open-access transmission service, RTO markets, and electric reliability standards.

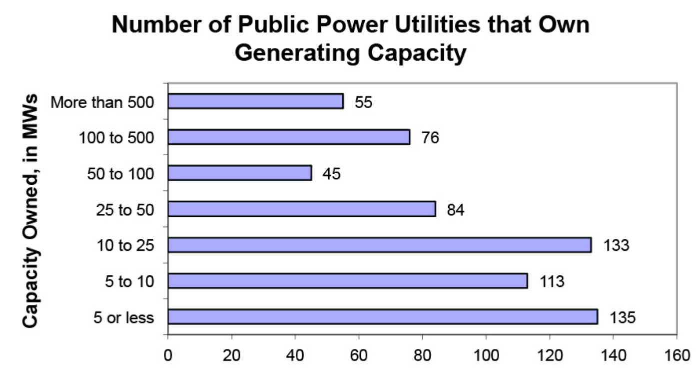
B. Resource Portfolio

Public power resource portfolios are diverse and reflect the supply alternatives available in each region of the nation. On balance, public power utilities are slightly more "green" than other industry sectors, because of our long-standing access to hydroelectric resources, and in recent years, increased use of natural gas.

Most public power utilities, particularly smaller ones, do not own generating capacity. Approximately two-thirds of end-use public power capacity is supplied by municipal joint action agencies or through purchases from other utilities and generating companies.



Source: Energy Information Administration, Form EIA-860, 2014 data



Source: Energy Information Administration, Form EiA-861, 2014 data

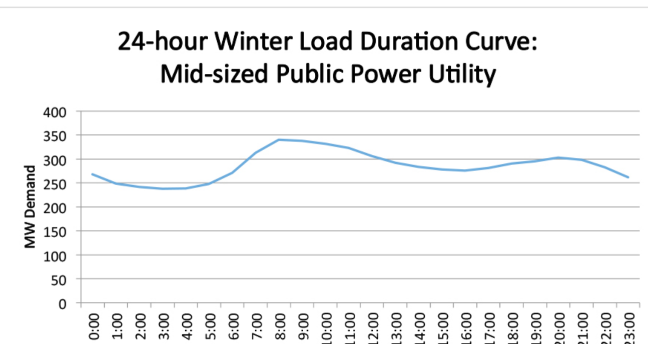
Public power is at the forefront in the adoption of renewable energy including wind, biomass, and solar. Nearly one-fifth of public power generation is provided by hydropower. A large number of utilities have signed long-term power purchase agreements with wind and solar generators. Nuclear energy, often through joint ownership with other utilities, also forms a substantial portion of public power supply portfolios.

Many public power utilities are net buyers of electricity from the wholesale market, generally through a mix of long term contracts and power purchase agreements, supplemented with spot market purchases. This approach takes advantage of our longer time horizon and lower cost of capital as compared to investor-owned utilities and merchant generators. We use ownership, long term contracts, and portfolio management to keep rates down and reduce exposure of our customers to volatile wholesale markets.

C. Customer Profile, Services, and Pricing

Public power customers look much like America itself, with a broad distribution across residential, commercial, and industrial classes and all the challenges that electricity customers everywhere may face. Some public power communities are quite wealthy, but most look more like small-town America than the prototypical rooftop solar customer.

The load characteristics of the typical public power customer mirror the utility as a whole. The typical public power residential customer has a monthly bill of just $106 and uses 932 kWh per month.



The figure above shows a typical daily winter load duration curve for a medium-sized APPA member.

Public power customers, even in small communities that are remote from the frontlines of electric restructuring, are very interested in new technologies and green energy.

Public Power Renewable Capacity

Nameplate capacity, in megawatts

		Public Power
Renewable Fuels		
Geothermal		220.0
Sun (Photovoltaic, Thermal)		56.9
Wind		962.2
Biomass Fuels		
	Agricultural Crop Byproducts	
	Black Liquor	131.4
	Landfill Gas	395.0
	Municipal Solid Waste	598.4
	Other Biomass Gases	170.2
	Other Biomass Liquids	2.0
	Other Biomass Solids	
	Sludge Waste	1.9
	Wood Waste Liquids	
	Wood/Wood Waste Solids	180.8
Hydro		21,170.0
Total Renewable Fuels		**23,888.8**

Source: Energy Information Administration, Form EIA-860, 2014 data

Public power participation in solar energy, through direct ownership, utility-scale purchased power, and non-utility generation has grown dramatically since 2014. APPA's analysis of the SEPA project database indicates that as of June 2015, 355 public power utilities had some form of non-utility solar power generation serving their communities. The cumulative amount of solar capacity serving public power communities has grown to at least 1,169 MW including a substantial base of small utility-scale projects.

	Number of public power solar installations	Cumulative MW capacity
Residential	67,185	322.31
Non-Residential	6,101	428.38
Total Non-Utility	73,286	750.60
Utility-scale	338	418.76
Total	73,624	1,169.45

Source: APPA Staff, Analysis of Public Power Solar Installations from SEPA Database, June 2015.

The public power non-utility installations shown above represent approximately 11 percent of total residential and commercial solar installations in the United States. Total public power solar capacity (including utility-scale) is just under six percent of total U.S. solar capacity installed as of June 2015.

With respect to retail electric services, public power utilities nearly always provide bundled electric services to their customers — what might be called plain-old electric service or POES, supplemented by community-specific special services such as conservation and energy audits. Rates for the typical residential customer recover the majority of revenues from kWh energy charges, in many cases supplemented by a modest customer charge.

Commercial and industrial rates for public power utilities are generally designed as they are at other electric utilities, comprising a fixed monthly charge, a demand charge based on the customer's maximum monthly kW demand, and a variable energy charge based on kWh usage. Some public power utilities have incorporated time-of-use (TOU) rates into their commercial and industrial tariffs. Public power utilities and their commercial and industrial customers also work with third parties for energy efficiency and demand response programs designed to curtail usage during peak periods.

Many public power utilities have key account programs to help large customers manage their energy usage, integrate customer-owned generation into customer and utility operations, meet specific power supply reliability and quality needs, and, to the extent possible, help ensure that electricity prices do not create a competitive disadvantage for these firms. APPA views the SEPA 51st State and APPA's Public Power Forward initiative as focused extensions of many customer service concepts that utilities traditionally offer to key accounts — through business practices that are scalable to serve large numbers of customers.

Electricity supply rates and reliability can be used as an economic development tool, to attract and retain businesses in a community, in conjunction with other services and amenities that local governments may offer. However, economic development measures that subsidize one customer or group of customers at the expense of others will weaken the community as a whole.

Ultimately, rate design in public power communities comes back to the same principles that apply to other utilities. Rates need to:

- Be fair and non-discriminatory across classes
- Be simple enough for customers to understand
- Encourage short-term and long-term economic efficiency through good price signals
- Avoid cross-subsidies beyond those needed to achieve agreed-upon social welfare goals (such as rates for low-income consumers)
- Achieve rate and revenue stability and adequacy to provide financial support to the enterprise
- Allocate risk efficiently to those best equipped to accept or mitigate those risks

D. Public Power Business Model

Public power utilities have no stockholders — other than the community itself — to pick up the tab. If a rate design does not recover the costs incurred to serve a particular customer or class of customers, including the common costs incurred by the utility, then the rates for other customer classes will exceed costs.

As not-for-profit, community-owned electric systems, public power utilities leverage their low costs of capital to finance long-term investments to build a least-cost, low-risk power supply portfolio. Investment policies are generally very conservative, reflecting our view that the community-owned utility must be operated to achieve the community's goals, rather than to take on risks that might maximize profits from the enterprise. Further, public power's reliance on tax-exempt debt means that the financial strength of the enterprise and the community become assets that will increase our bond ratings and help to reduce the cost of financing capital investments.

Many public power utilities are very interested in new technology and innovation, but their size and business model, as small publicly-owned enterprises, has pros and cons. On the one hand small-scale projects can be initiated quickly as the utilities are self-regulated. However, these projects generally lean toward limited scope demonstration of commercial potential given the scale, scope, and complexity of projects that can be managed by a small utility. Public power utilities are very interested in creative micro-projects, but less able to support original research and development and large-scale projects than large investor-owned utilities.

Many public power utilities have yet to modernize their information technology (IT), operations technology (OT), and customer interface/metering infrastructures. The immature state of IT/OT and advanced metering infrastructure is both a challenge and an opportunity. Not being early adopters in this space means small public power utilities have a much larger set of hurdles to fully modernizing their infrastructure and business processes.

Conversely, they may be able to avoid the mistakes of others and adopt solutions that are well adapted to a smart grid future. IT, OT, and AMI can be designed around business objectives, avoiding the mistakes many companies make in acquiring technology and installing infrastructure and systems before fully developing the business case. For typical public power utilities, off-the shelf rather highly customized applications are essential.

Regardless of the new services a utility decides to offer, IT, OT and AMI must support core business objectives, e.g., meter reading, asset management, and power outage management. Integration of new rooftop PV and other DER is just one of a set of business use cases.

These insights and characteristics have important implications for the SEPA 51st State dialogue and are summarized below.

II. Lessons Learned and Characteristics that Drive the Transition to the 51st State

APPA staff sought to identify characteristics of the current solar industry, as well as previous restructuring initiatives, that will drive the direction that public power utilities are likely to pursue. These characteristics and lessons learned are not unique to public power utilities, although our responses may well be different than other industry segments.

A. Electric Restructuring: Lessons from the Last Round

Past electric restructuring initiatives have taught us that the benefits of restructuring are often oversold, that much of the customer savings were predominantly wealth transfers from one group of market participants to another, and that the complexity of the transition to new business models and regulatory rules can often lead to real losses of efficiency and exercise of market power.

On the plus side, restructuring can lead to the introduction and more rapid deployment of new technologies that can increase economic efficiency of resource allocation and exchange, ultimately benefiting consumers and the nation as a whole.[2]

Wholesale open access transmission broadened access to competitive sources of electricity over wider geographic areas. RTOs and ISO extended these benefits through the real-time dispatch of bid-based markets in large control areas, albeit with sometimes catastrophic consequences for customers and market participants when market design flaws created or magnified market power and incentives to manipulate markets. Indeed, litigation of the California energy crisis of 2000-2001 continues to this day.

APPA does not see that substantial benefits have accrued to customers from retail competition —often called customer choice. While there is some evidence that large industrial and commercial customers have achieved savings, residential customer savings have been minimal. The simple contra-factual comparison of rates in retail choice states versus other states that retained bundled franchise monopoly service shows no marked lower costs in deregulated states compared to their vertically integrated neighboring states.[3 4]

Leonard Hyman and William Tiles[5] note that: "[e]lectricity deregulation began in the 1980s with three articles of faith: regulated firms operated inefficiently, competition would force them to reduce their costs, and it would force them to pass on those reductions to consumers." They find that "electricity restructuring reduced air pollution by hastening the retirement of aging coal-fired stations, raised industry operating efficiency and stirred long-dormant thought processes in an industry running on autopilot." Generators improved their operating efficiency and utilities learned to do more with fewer employees. However, the promised benefits to customers did not materialize. According to Hyman and Tiles,in the U.S., states with high electricity prices deregulated to reduce prices, but their prices still remained above the U.S. average and the percentage differential did not diminish, as shown in Hyman and Tiles' figure 1 below.. Deregulation did not change the fundamental factors that produced high prices.

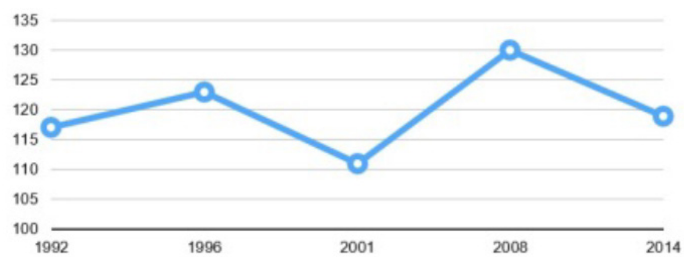


Figure 1. Average price to ultimate customers in deregulated states as percentage of U.S. national average price.

Hyman and Tiles suggest five design flaws that caused electricity restructuring to fall short of expectations:

1. Policymakers misunderstood human motivations. They did not understand the degree of operational efficiency that utilities had accomplished in the existing regulated industry structure. Moreover, new entrants "had a different goal, to maximize profit, preferably legally but not always. It was never clear why all those profit maximizers, acting separately, would miraculously produce the lowest priced or most reliable product."
2. "Neither policymakers nor industry players fully understood two cost of capital concepts: that shifting the risk does not make it go away, and that the new unregulated generators had substantially higher costs of capital because they were riskier."
3. Deregulation produced transaction costs from the structural unbundling of companies into separate entities, "each with its own profit and loss statement, and none with full control of the product or motivation to bring prices down for the ultimate consumer."

4. “Customers faced additional complexity, an array of service offerings that required professional expertise to fathom – and everyone offering a new service expected to be paid.”
5. “Politicians concentrating on specifics rather than policy confused means with ends and undermined the market.”

Much of the benefit achieved from electric restructuring is concentrated and limited to the wholesale level, and is directly attributable to a single set of improved electricity production technologies: highly efficient natural gas turbines and combined cycle generation. This technology is responsible for much of the downward price movement in wholesale energy markets. Bid-based RTO energy markets, in conjunction with natural gas price spikes, are likely responsible for a major portion of the price volatility experienced in wholesale markets, as all generators in these markets are paid the market clearing price.

The rapid introduction of merchant generators operating gas turbines and combined cycle plants has placed competitive pressures on incumbent generation owners, particularly coal-fired and aging nuclear plants, for much of the past 20 years. When natural gas prices have been high, a “dark spread” of profitability re-emerged for merchant coal and nuclear plants. When natural gas prices have been low, customers have benefited, even as merchant generators have struggled.[6]

Merchant plants have encountered severe problems remaining profitable over time based on energy market revenues, particularly in deregulated states and have thus repeatedly sought additional sources of revenue through RTO capacity and ancillary service markets.

Borenstein and Bushnell make very similar points about wholesale and retail electric restructuring over the last twenty years and apply those lessons learned to the current focus of restructuring—residential solar.[7]

B. Characteristics and Starting Points for the Current Transition

Borenstein and Bushnell write that:

> The growth of wind and solar generation sources raises two issues that are now coming to dominate policy discussions among utilities and policy makers: (1) economic and technical management of intermittent-production resources for which costs are largely sunk before production begins and (2) policy towards distributed generation resources that are on the property of the end user (so-called “behind the meter” generation). The latter is primarily an issue with rooftop solar PV today, but could expand to batteries and other generation or storage devices in the future.[8]

As discussed below, APPA believes solar is on the verge of a transition to widespread deployment in much of the U.S., driven by commercial competition, Renewable Portfolio Standards, climate change mitigation strategies, and community interest in and commitment to renewable energy. The issue for APPA becomes how to help public power utilities manage this transition while assuring benefits to the communities they serve.

Other technologies, particularly energy storage, are not yet commercially viable, except in certain limited applications, unless they are heavily subsidized or utilities are subject to mandatory purchase requirements. In contrast, there is a suite of conventional and advanced customer-side technologies including smart thermostats and grid-connected appliances. We discuss those technologies briefly in section III. Grid-controllable electric water heaters and heat pumps can be managed to make more efficient use of the grid, if visibility, coordination, and control issues can be resolved.

Several factors must be considered in the growth of solar.

1. Solar and DER Penetration

As of December 2015, solar energy had reached a significant milestone in the U.S., with MWh output doubling over the previous year and total installed capacity from all sources increasing by 7.3 GW.[9] Despite the rapid growth over the last two years, solar capacity still amounts to only 2 percent of the installed generation capacity in the United States.[10] While solar energy in Hawaii and California has reached substantial scale, it has yet to reach a dominant market share in most states. Solar capacity additions, while noteworthy, come at a time when much of the industry is in a capacity addition holding pattern. Coal generation is increasingly targeted for early retirement based on competitive pressure from natural gas, coupled with imminent burdens of increased environmental regulations, including, but not limited to the Clean Power Plan (CPP). The current Supreme Court stay on the CPP may slow this trend but is not likely to change the direction. Coupled with low to flat demand growth, existing capacity resources are generally adequate.

As baseload dispatchable coal resources are retired they will need to be replaced with other resources to maintain reserve adequacy, meet customer load requirements, and provide essential reliability services.

2. Solar Resource Costs

Solar, particularly at the community and utility-scale, is increasingly becoming an economic source of energy and to a limited extent, a capacity resource, in many parts of the country with high solar irradiance. In recent months, we've seen solar power purchase agreements ranging from just below $40/MWh to the mid-50s.[11] Various studies have cited rapidly decreasing capital costs.

Nonetheless, in much of the U.S., natural gas still appears to be the most competitive source of new generation. The lesser interest in gas generation can be attributed to the fact that many utilities and merchant generators have already invested heavily in gas. Interest in solar and wind represents a physical hedge against future natural gas price increases and climate change obligations.

3. Rooftop vs. Utility-scale vs. Community Solar

The cost of residential rooftop solar development appears to be decreasing. However, rooftop solar still costs at least twice as much per KWh as corresponding utility-scale projects. One source cites panel, inverter, land, and balance of system costs of $1.58 per watt for utility-scale solar, as opposed to $3.46 per watt for residential solar and $2.19 per watt for large commercial projects.[13] This cost differential is attributable to economies of scale, the ability to mount panels on tilt axis to increase output, and the lower costs of integrating larger installations into utility operations.[14] Utility-scale projects often have the added benefit of being sited in areas with better irradiance than projects that are closer to load centers.

Community solar projects appear to have many of the costs advantages of utility-scale projects, with the added advantage of being sited closer to load, avoiding significant transmission costs and line losses, while being relatively easy to integrate into distribution system operations. For many utilities in large urban areas, land may not be available for community solar projects. For public power utilities located outside of major urban areas, land may be available quite close to load.

4. Residential Rooftop Solar: Pricing and Rate Design

The incentive structure the U.S. has created for rooftop solar has several design flaws. Net Energy Metering (NEM), in conjunction with retail rates that recover all or nearly all utility costs through a cents per kWh commodity rate, is likely to over-compensate rooftop solar output for the energy value of the solar output, compared to alternatives such as utility generation or purchases from the wholesale market. During certain hours of scarcity conditions, the wholesale price of energy may well exceed typical residential rates, but those hours are few and far between.

DERs, including residential rooftop solar, may well provide long-term benefits to the distribution system, such as avoided distribution capacity costs and some types of ancillary services. If coupled with energy storage, solar may support more effective utility-scale load management. However, none of the benefits are achievable without integration of these resources into utility planning and operations, which may or may not be cost-effective except as part of a utility innovation plan.

It is sometimes argued that rooftop solar customers are "banking" their surplus output with the utility for later use. The flaws in this argument can be illustrated by a simple example.

> Imagine the Wellandia Municipal Utility serving Wellandia — a small, wealthy city with no business and no industry. Every residential customer has a rooftop solar array that is sufficient to cover his/her entire annual

kWh consumption, producing a surplus during the day and drawing energy during other hours.

Assume for simplicity that each residential customer in Wellandia has a perfectly flat load, day and night, of one kW per hour. Assume that each customer's 3 kW solar array achieves a 100 percent capacity factor over eight daytime hours. The utility has sized its distribution network to deliver all surplus energy produced by the customer to the bulk power system, while meeting all customer needs during periods when solar output is not available through market purchases.

Under NEM pricing, the customer's monthly bill would be zero, although the utility would be receiving 2 kWh per hour per customer during the eight solar output hours to sell on the wholesale market and buying 1 kWh per hour for each customer during the sixteen off-peak hours. Unless wholesale market prices during solar output hours (plus any green generation credits) are more than twice as high as off-peak market prices, there would be no source of revenue to pay distribution system and other costs, and the Wellandia Municipal Utility would soon be bankrupt.

Of course, in a world of high renewables and "duck curves", one would expect just the opposite—high solar output in a region is likely to depress daytime energy prices. Conversely, prices are likely to spike upward in the late afternoon and early evening hours, as natural gas and other fossil generation is dispatched to meet the evening customer load and replace solar generation.

NEM, particularly in the simple single energy charge form, sends pricing signals to consumers that encourage inefficient investment. Energy-only NEM pricing is unlikely to be economically efficient or commercially sustainable for utilities.

Identifying the issue does not answer the question of how to price either electricity consumption or production at the customer level. Getting the incentives right is hard. Our purpose in this section is only to identify the need for more efficient pricing as one of the starting points for a successful transition to the 51st State. Starting off with business models predicated on market design flaws and cross-subsidies does not bode well for a sustainable transition.

For example, some utilities have used increasing block energy rates to accomplish social policy goals. Under these rates, the price for the initial energy consumption tier is set very low, to provide life-line consumption rates for small, presumably low-income customers.[15] These customers may barely cover the variable costs incurred to serve them. Conversely, high usage customers may pay high tier energy rates that are several multiples of the cost of wholesale energy, to encourage energy conservation. As more residential customers install rooftop solar arrays, more remaining fixed costs of the distribution system are shifted—in this case to their neighbors in high consumption tiers. This will drive more customers to add rooftop solar, increasing the share of costs that must be recovered from a dwindling remaining customer base.

III. First Steps to a Sustainable Future – Implications for the Transitional State

From the discussion thus far, APPA draws the following inferences on first steps for public power utilities to build on the their fundamental strengths and respond to emerging customer preferences, business and technological opportunities, and public policy goals. These first steps include:

- Initial measures likely to lead to sustainable long-term business practices and customer relationships.
- Experimenting with various approaches to utility controlled community-scale solar to identify business and operational challenges.
- Starting to realign retail customer rates with economic costs and cap exposure to NEM regulatory arbitrage.
- Modeling and managing risks to the utility and customers driven by external factors.
- Constant communication with governing boards, customers, and community stakeholders on the utility's plans.

1. Sustainable Business Practices

Solar photovoltaic (PV) is on the verge of becoming a mature, fully commercialized technology – and needs to be treated as such. Public power utilities cannot afford to ignore it. Solar PV is early on the "S curve" for technology adoption, with a nationwide market share of 1 to 2 percent but growing rapidly. It is the right time to get incentives and business rules right and create a commercially sustainable path forward.

The path forward will require building a set of planning, interconnection, operations, and communications technologies and business practices to support solar PV integration. These technologies and business practices are more mature at the wholesale/bulk power level than at the customer DER level.

Public power utilities must continue efforts — through pilot programs where necessary — to integrate solar into utility operations, manage and mitigate DER supply characteristics, and develop better use/application cases to support offerings by third-party vendors.

Most public power utility customers can't participate directly in residential rooftop solar. Their incomes and bills are too low to make it worthwhile or they live in unsuitable housing. But customers can participate as subscribers in community solar programs or through utility scale solar. This model is particularly well suited to public power utilities.

2. Community Solar

Community solar provides an important opportunity for public power utilities to gain operational experience by integrating solar resources into their distribution SCADA systems, and working with third party suppliers. While some public power utilities may elect to own and operate community solar facilities directly, a partnership with an experienced third-party developer that is eligible to take advantage of the solar investment tax credit, is likely to be more economic for the utility and its ratepayers.

Community solar also provides an opportunity for public power utilities to experiment with various customer subscription models. Many public power utilities may decide to roll the costs of community solar projects into their retail rates, so that all customer classes bear the costs and receive the benefits. Others might use a scalable subscription model in which individual retail customers subscribe to take and pay for a portion of the output of the facility through bill credits against their electricity consumption.

In most cases, community solar subscriptions will be sold at a premium above the utility's corresponding retail rates. Some utilities may elect to charge community solar participants at the equivalent of a NEM rate. However, care must be taken to structure community solar arrangements so that they do not resemble a financial security that might trigger concerns at the Securities and Exchange Commission.[16]

Recent experiences of a number of APPA members indicate widespread, diverse interest in community solar projects. One large municipal joint action agency, American Municipal Power, recently executed an agreement with a subsidiary of NextEra Energy Resources, LLC to construct 80 MW of distribution scale solar in member cities, with 28 projects identified so far and more likely to come in the future.[17]

Another joint action agency is working with a large Fortune 500 company with major loads in several agency member cities to meet corporate environmental stewardship goals. The agency's community and utility-scale solar projects will help anchor those industrial electrical loads — and the jobs that come with them — to the host communities and the state.

3. Rate Design

Public power utilities must take first steps to realign retail customer rates with economic costs and cap exposure to NEM regulatory arbitrage. Many public power utilities may face minimal exposure to residential PV for a number of years. As public power residential electric rates tend to be less than those of investor-owned utilities, we are somewhat less likely to have high tail block rates that increase the incentive to install solar PV.

The typical bill of a public power residential customer, at $90 to 100 per month, does not rise to a level that would cause most customers to invest $15,000 or more in a solar PV array or to sign a 20-year lease agreement.[18]

For many public power utilities, a simple cap on the load or number of rooftop solar customers eligible for NEM would suffice to limit the utility's immediate financial exposure and the potential cross-subsidy by non-rooftop customers. A variety of other rate mechanisms can be used. Existing rooftop solar customers can be grandfathered, coupled with decreasing incentive payments for new customers. Another option is a buy-all/sell-all model in which the customer's load is recorded on one meter, with a separate feed-in tariff rate for the solar array that is indexed to wholesale market prices and other community benefits.

It is abundantly clear that NEM in conjunction with an energy-only tariff will lead to cross-subsidies among DER and non-DER customers. A cap on NEM participation may cap the utility's financial and operational exposure and is one second-best solution for utilities that do not have advanced meters capable of supporting demand charges and TOU rates. But this cap does not align customer prices and incentives with the economic costs incurred by the utility. NEM treats the grid as a big lake into which everyone can dump their surplus for free and draw it out for free. In the absence of energy storage, there is no inter-temporal electricity market — all electricity must be used as it is generated.

To improve utility economic efficiency, treat all customers fairly, and send good price signals to customers interested in DER — based on the economic costs and benefits they bring to the table — utilities should adopt a multipart rate design. The design should include time-of-use energy charges, a capacity charge based on the customer class contribution to the utility's peak loads at various functional levels (production, transmission, primary distribution), a customer service charge for servicing the account, plus a fee for costs that can be directly assigned to the customer (e.g., a DER meter). Some utilities are considering critical peak pricing approaches, using real-time prices to signal the need for immediate load reductions.

All rate design changes are likely to be painful and raise opposition, regardless of industry sector. They can and will create winners and losers. Public power utilities are no more immune to pressure against change than other industry sectors.

Current market conditions, however, do create a window of opportunity for utilities to redesign rates to more closely align with actual costs incurred to provide service, on a revenue neutral basis. The real, inflation-adjusted costs of providing electric service have fallen for many utilities with the decrease in natural gas prices and little to no demand growth, allowing existing resources to meet customer demand. A revenue-neutral change in rate designs has a much greater chance of success now than in periods of rapid price increases.

APPA encourages public power utilities with AMI to consider a gradual move to a separate customer charge, a demand charge, and time-differentiated energy charges. For utilities that have yet to install AMI, simple changes to cap NEM participation and a gradual increase in the customer charges may be all that is appropriate.

4. Community Outreach and Policymaker Education

Community and governing board education is critical, from the outset. New programs and rate design changes need a well-articulated goal and reasons. Even as the utility is engaging in these modest initial steps, other industry sectors are changing. Most of the SEPA swimlanes are deeply affected by the actions of other market participants and regulators.

IV. Planning the Transition to the Future State

As noted in its Phase I submission, APPA believes that the public power 51st State should retain key elements of current industry structure for production and delivery, with modifications to facilitate the development of modern, efficient energy resources — including DER, utility and community-scale renewables, traditional supply resources, and customer-focused energy efficiency and demand-side management programs. Individual communities will make very different choices, based on the available economic alternatives and the community's preferences, as well as state and federal regulatory directives.

The key elements of the transition to the future state include:

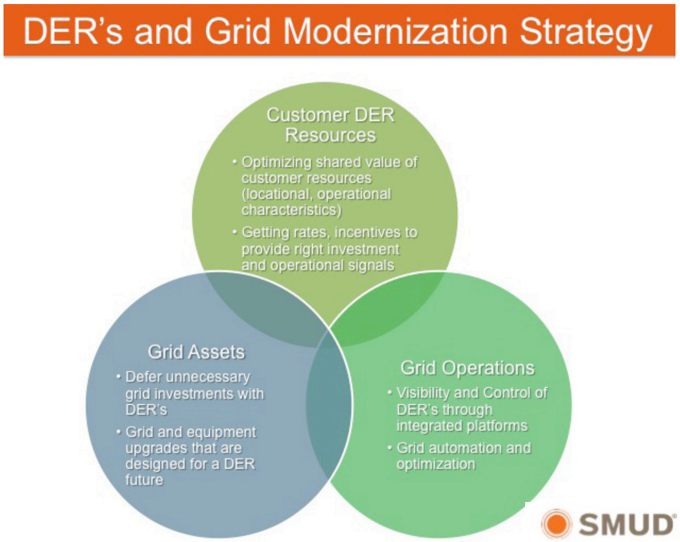
- Recognizing the real economic costs and risks of alternatives —and reflecting them in utility specific rates and service offerings. Subsidies can create an unsustainable, high-DER future.
- Aligning customer interests with those of the utility and third-party suppliers at the grid edge and wholesale/bulk power levels.
- Capturing the benefits of DER integration for customers and utility system planning and operations.
- Developing the utility business and operational technology infrastructures to sustain these offerings over time.

APPA envisions a future state with an enhanced, modernized grid that includes new mechanisms to identify and value the discrete attributes of various distribution services and alternative supply and demand resources including traditional supply, DER and new renewables, demand response, and energy efficiency programs. While perhaps not dramatically disruptive, the scope of change will be significant and the pace will be brisk. A number of key changes will signal that the transition from the current state to the future state is proceeding in an effective way. These changes include:

- Development of new product offerings and value-based pricing mechanisms for both platform services provided by utilities to DER customers — e.g., generation dispatch, storage discharge, backup generation, interconnection, data collection and management — and for products — e.g., energy, capacity, ancillary services — provided to the grid by DER resources.
- Increased deployment of DERs that meet a value test for participating customers, the utility, and the community as a whole. This could include structuring of NEM programs to compensate DER customers based on the incremental value of the electricity (e.g., value of solar), with proper accounting in rates for the value of the grid to DER customers.
- Increased deployment and utilization of advanced technologies and information communication technologies to facilitate communication, system control, resource dispatch, and dynamic pricing.
- Increased deployment of non-utility generation resources on both sides of the meter.
- Management of foreseeable impacts from distribution-level decisions on bulk power system operations and the wholesale market – and vice versa.
- Development of workable industry business standards to support interoperability and the integration and use of new technologies.
- Enhanced coordination between distribution-level and bulk-level planning and operations (e.g., considering aggregation of local DERs as substitute for wholesale generation or bulk transmission).

The Grid Modernization Venn diagram below, used with the permission of the Sacramento Municipal Utility District, captures this vision. Co-optimization of customer DER resource investment and utilization with grid asset planning, investment, and operations can capture significant efficiencies that would be lost if utility and customer decisions are not aligned.

The end result will be some level of integration of customer-side resources into utility operations. The question is — how much, when, and how? Should coordination and control be limited to safety, e.g., customer back-up generators that operate behind disconnect switches that isolate them from the distribution system? Should coordination be limited to the visibility provide by an advanced real-time energy meter, with no operational control over the PV inverter? Or will distribution utilities be able to integrate DERs and other devices into utility operations to co-optimize reliability and costs?



Electric utilities have over a century of experience with integrated electric system operations. Such large-scale integration, through visibility, coordination, and control, has captured substantial reliability and economic benefits for consumers. We've seen vertical and horizontal integration within a single company and integration through various spot markets and hierarchical regional system operator schemes, and through the alignment of interests via long term contracts.

Market structure is a choice and different market structures have different potential costs, benefits and performance attributes. Analysts and observers often come to very different recommendations.[19] As noted at the outset, APPA elected to not focus in this paper on wholesale market structure issues. Rather, our focus in on the distribution utility business model.

APPA expects many of its members will remain largely anchored in today's cost-of-service based utility business model, characterized by utility ownership and operation of electric power generation, transmission, and distribution assets, with a largely "one-way" relationship with customers, within which utilities provide the entire energy requirements of its customers, with little or no direct day-to-day interaction with customers.

See the "Today's Model" column in "The new utility business model", next page. Within this model, utilities have long had key account customers, with special power quality needs and their own back-up generation. Utilities of all types have sponsored a variety of energy audit, conservation, and load management programs. In other respects, most utilities do not provide customized services to their customers. In contrast, Model 1 envisions an evolution to a full distribution service provider that procures and sells DERs, as well as other customized services, to its customers. Under Model 2, the distribution utility becomes a platform provider and distribution system operator that facilitates connecting DER providers and other energy service providers to the customer. Model 3 is a pure poles and wires business with no relationships with end use customers.

APPA anticipates that its members will make a variety of choices along what is really a continuum of alternatives, although most will gravitate toward attributes that fall between Today's Model and Model 1. Some will also act as platform providers to facilitate customer access to high quality third party service providers.

Within this framework, the question is, how does the utility decide what to do and map out a strategy to get there? The core challenge for APPA's Public Power Forward initiative is to help APPA members make carefully considered modifications to the public power business model to adapt to the structural factors they face and provide the enhanced retail services their customers want, such as distributed generation — including rooftop and community solar, demand response, electric vehicle charging, energy storage, and energy efficiency, while ensuring that public power utilities continue to meet customer and community expectations of safe, reliable, clean and affordable electric services. APPA has identified the following steps in this strategic planning process — many of which mirror the "swimlanes" and "roadblocks" that SEPA identified:

Map and Respond to External Policy and Market Forces

Policy and market forces include the many factors discussed above, including the relative price of alternative power supply options over the utility's planning horizon; identifying national, state and local policy goals and requirements, such as Renewable Portfolio Standards and carbon mitigation; economic forecasts of customer load growth in the community; and new regulatory requirements and public expectations for infrastructure security and resiliency.

The new utility business model

	Today	Model 1	Model 2	Model 3
Business model	Centralized, cost-of-service model	Full service provider	Platform provider	Poles & wires business
Customer relationship	• Largely 1-way • Some net metering for solar	• Driver of DER (selling & procuring) • Customized energy solutions	• Facilitate connecting DER providers with customers	• N/A
Services	• Energy, transmission, distribution planning and operations • Traditional utility incentive programs • Low income and med rates/programs	• Same as today, plus: • Distribution grid operations (dispatching, balancing) • DER integration • Full service bundling	• Grid planning and operations (dispatching, balancing) • DER integration	• N/A
Assets	• Central generation • Poles & wires	• Central generation • Poles & wires • DER	• Poles & wires	• Poles & wires
Revenue sources	• Traditional energy and demand payments with some fixed charges	• Energy & capacity payments (rates/ price signals) • DER sales	• Transaction fees • Integration service fees	• Fixed distribution charges (asset rent)

3rd party vendor-driven investment, value & revenue potential

Utility-driven investment, value & revenue potential

SMUD

Identify Customer and Community Preferences for New Services

Every state and community starts in a different place. Utilities must know what their customers want. We all live in a Google/ Amazon world, but Kansas is not California. Pocketbook issues weigh heavily on many public power communities, which may make their risk preferences and interests in electric restructuring quite different than other communities. Public power utilities take this focus on the community seriously.

Utility Risk Management

Public power utilities need to assess their internal strengths and weaknesses and the effectiveness of the interim "first steps" described above. They must develop a risk management strategy that identifies and manages the utility's cost curve, price competitiveness, and financial risks, including existing policy choices (e.g., commitments to serve low-income customers) and potential stranded costs that may limit options going forward. This process will identify the financial and technical resources available for the next step.

Community Grid Modernization Plan

Utilities must develop a grid modernization plan that integrates external factors, community preferences, and the utility's risk management strategy into a community-specific innovation plan.

Services: The plan needs to address the development of new customer services, including a la carte "opt in" services for customers — key account conservation and load management services, back-up power supply, power quality, and micro-grids for reliability and integrated energy services. Many of these services may be offered on a fee for service basis. Other services may be offered at zero cost, where the external benefits to the utility exceed private benefits e.g., conservation; load management to provide grid support.

Business Partnerships: Many public power utilities will look to third parties to develop and provide enhanced services. New ground rules and relationships need to be developed for behind the meter services integrated across the "grid interface" into utility operations, to align the interest of the customer, the utility, and the third party service provider. Many public power utilities will look to their joint action agency to either provide these services or help arrange third party contract support.

Resource Planning: Public power utilities will benchmark supply options of all types, including community solar and private solar against other utility-scale alternatives. Key factors that differentiate public power from investor-owned utilities include the local community orientation, the longer time horizon, and lower capital cost balanced by smaller scale and lower risk tolerance. Public power utilities may also have access to community resources that are not open to other utilities, such as access to brown-field sites for solar development.

Distribution System Modeling, Planning and Operations: In addition to developing a technology plan that provides the reliability that customers expect, the utility needs to explore the benefits and costs of integrating customer DER into real time utility operations. Customer-side DERs may avoid the need for some distribution system investments by reducing peak loads on certain circuits. However, a high customer DER future is more likely to increase the total capacity loadings on the distribution network by varying energy supply and demand. This pattern may well mimic the increased volatility of supply sources and prices on the bulk power market.

The utility's technology plan must manage this increased level of variability. Capturing benefits from a high DER future requires a much greater integration of load and resource visibility and control across the customer-utility interface than is feasible today. It is possible to accomplish some of this coordination through customer actions, but the long-term solution would require automation, with some ability for the utility to dispatch customer DER, to provide voltage and frequency support, and keep distribution circuit loads within limits. Smart grid applications will provide much of the information required to perform load management but this too, needs to be automated, given the number of nodes that would need to be monitored.

Consumer and Community Education: Most electricity customers are not regularly engaged with their electric utility — nor should they be. If their electric bill is $70 per month, the customer simply wants a bill that stays at $70, an easy way to pay that bill, and the assurance that if the power goes off, it's coming right back on. Often, those of us who are interested in electric restructuring and new technology over-estimate the general public's interest in getting involved in these decisions, as well as their understanding about the complexities of electric power supply and delivery. APPA member experience with residential customer conservation programs is a case in point.

Sustained interest and understanding are difficult to attain, because people are busy and have more important things to do than to study their electric bills and find new opportunities to save $3 per month. The key decision point is when customer investment decisions are made, such as installation of new appliances, buying an electric vehicle, or changing out a thermostat.

Conversely, a small group in any community is highly engaged on these issues because they care about rates, social justice, environmental issues, or customer privacy. The key is to use communications technology to allow customers to engage when and how they need and want to – or to not do so if they so choose. Public meetings, and utility studies help, but day-to-day outreach through customer service is the most effective.

Rate Design and Regulation: Ratemaking will ultimately follow the rate design principles outlined earlier — comparability and non-discrimination across customer classes, simplicity and economic efficiency, avoiding regulatory complexity and large unsustainable subsidies; rate and revenue stability, and proper allocation of risks to those who cause the risk and are best able to bear the risk.

The key challenge in the future state is to determine how to bundle and unbundle a service that for most end-use customers is a very simple, homogeneous product – continuous electricity supply at 110 volts, 60 cycles per second. Supplemental services will be provided on an opt-in/fee-for-service basis. APPA anticipates that these new services could be a significant source of new revenues, but they will still be small relative to revenues from electricity sales.

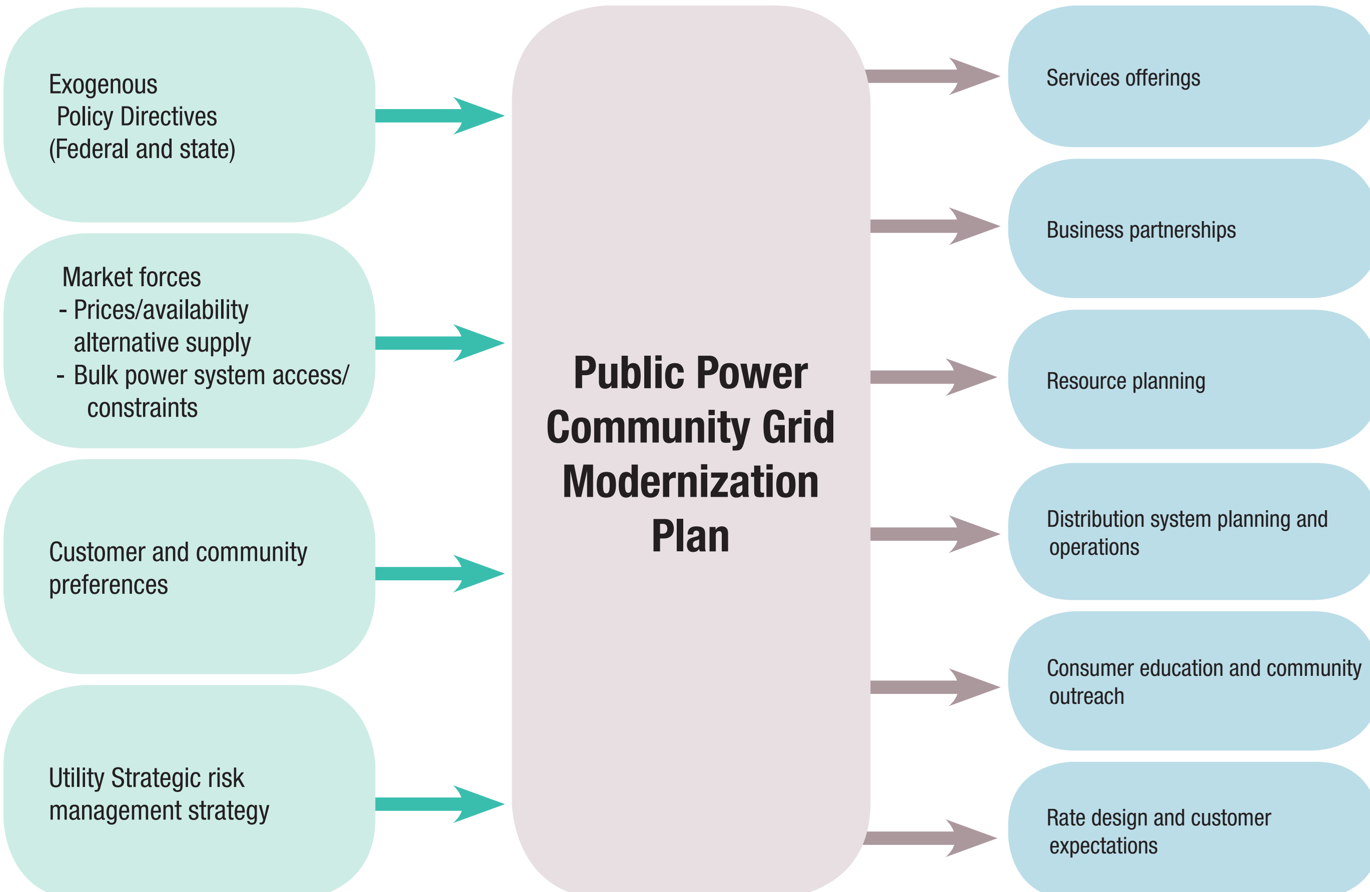
Conclusion

Thank you for the opportunity to participate in the SEPA 51st State process.

The figure, on the next page, graphically presents the roadmap we outlined above for public power utilities in the 51st State. Like with all good roadmaps, each traveler needs to pick their own destination. APPA's role is to identify easier paths forward and roadblocks on the way.

The final table summarizes key steps in the transition to the future state and corresponding elements of this future state.

Public Power Swimlanes for the Transitional and Future State



The Public Power Forward Strategy

Current State Description	No Regrets Steps for the Transitional State	Future State Strategy	
		Strategic Goals	**Actions**
INTERNAL • Public power utility characteristics • Strengths/deficiencies • Resources portfolio and options • Distributions system self-assessment • Customer profile, service and pricing • Community preferences EXTERNAL: • Lessons learned from previous restructuring • Solar and DER penetration/ forecasts • Solar resource costs versus other options • Pros/Cons utility vs. community Vs residential solar	• Sustainable business practices • Pilot programs on DER Integration and other new technologies • Community solar • Rate design and contracts – manage net energy metering risks • Community outreach and governing board support	• Reflect real economic costs and risks in rates and service offerings • Align customer, utility and third-party supplier interests at grid-edge • Capture benefits of DERS and other new technologies through resource integration into operations • Deploy new utility business and operations technologies • Manage risks	• Product offerings: value-based pricing of services • DER deployment based on grid value • Advanced IT/OT • Balanced portfolio of utility scale, community and customer resources • Coordinated operations across bulk power, distribution utility and customer interfaces • New business standards and practices • Manage risk exposure in wholesale markets

Footnotes

[1] APPA is the national service organization representing the interests of publicly-owned electric utilities in the United States. More than two thousand public power systems provide over fifteen percent of all kilowatt-hour sales to ultimate customers. APPA's member utilities are not-for-profit utility systems that were created by state or local governments to serve the public interest. Public power utilities are accountable to elected and/or appointed officials and, ultimately, the American public.

[2] See: "The U.S. Electricity Industry after 20 Years of Restructuring," Severin Borenstein and James Bushnell, Revised May 2015, The Energy Institute at Haas, University of California- Berkeley, EI @ Haas WP 252R, https://ei.haas.berkeley.edu/research/papers/WP252.pdf . Also published by the National Bureau of Economic Research as NBER Working Paper No. 21113, April 2015.

[3] See American Public Power Association, 2014 Retail Electric Rates in Deregulated and Regulated States, April 2015, at http://publicpower.org/files/PDFs/2015RetailRatesReportFinal.pdf.

[4] See also: "Retail Choice In Electricity: What Have We Learned In 20 Years?" Mathew J. Morey and Laurence D. Kirsch, Christensen Associates Energy Consulting LLC prepared on behalf of the Electric Markets Research Foundation, February 11, 2016. http://electricmarketsresearchfoundation.org/uploads/3/4/4/6/34469793/retail_choice_in_electricity_for_emrf_final.pdf

[5] http://oilprice.com/Latest-Energy-News/World-News/why-electricity-deregulation-fell-short-of-expectations.html

[6] See for example: "PJM prices down 32 percent last year due to low fuel costs, demand," IHS The Energy Daily, March 11, 2016.

[7] Borenstein and Bushnell, 2015, id.

[8] Id. at 21.

[9] Solar Industries Association, U.S. Solar Market Sets New Record, Installing 7.3 GW of Solar PV in 2015, February 22, 2016 at http://www.seia.org/news/us-solar-market-sets-new-record-installing-73-gw-solar-pv-2015.

[10] According to the Solar Energy Industries Association, there was 22 GW of solar generating capacity installed in the United States as of Q3 2015, against 1,173 GW total capacity.

[11] See for example: http://www.utilitydive.com/news/the-top-10-trends-transforming-the-electric-power-sector/405798/; "Palo Alto, California, Approves Solar PPA With Hecate Energy At $36.76/MWh! (Record Low)," Clean Technica, February 23, 2016; http://cleantechnica.com/2016/02/23/palo-alto-california-approves-solar-ppa-hecate-energy-36-76mwh-record-low/; "LADWP Board Approves $52/MWh solar contract," Megawatt Daily, March 2, 2016; "Cheapest Solar Ever: Austin Energy Gets 1.2 Gigawatts of Solar Bids for Less Than 4 Cents," GreenTech Media, June 30, 2015, http://www.greentechmedia.com/articles/read/cheapest-solar-ever-austin-energy-gets-1.2-gigawatts-of-solar-bids-for-less.

[13] See http://solarcellcentral.com/cost_page.html, accessed March 14, 2016.

[14] See for example, Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area, The Brattle Group, July 2015.

[15] It can be difficult to target or limit lifeline rates to low income customers. Many low-usage customers are affluent.

[16] Samantha Booth, Here Comes the Sun: How Securities Regulations Cast a Shadow on the Growth of Community Solar in the United States. UCLA Law Review 61 UCLA L. Rev. 760 (2014), pp. 760-811

[17] http://www.publicpower.org/Media/daily/ArticleDetail.cfm?ItemNumber=45340

[18] See: http://www.sunrun.com/solar-lease/cost-of-solar; According to the Sunrun web site: "On average the total cost of solar installation can be between $15,000 to $29,000 for average sized systems sized between 4kW and 8kW."

[19] See for example Corneli's advocacy for a competitive DER future in 2030, compared to Kihm's support for a utility-driven high DER future in 2030 in: Electric Industry Structure and Regulatory Responses in a Distributed Energy Resources (DERs) Future, Steve Corneli (NRG) and Steve Kihm (Seventhwave), Lawrence Berkeley National Lab, FEUR Report No. 1, November 2015, LBNL-1003823 https://emp.lbl.gov/sites/all/files/lbnl-1003823_0.pdf