



NextGrid: Utility of the Future Study Working Group 7 Meeting

June 19th, 2018

10:00am-1:00pm CST

Agenda/Meeting Materials

- 1) Welcome and Introductions
- 2) Speakers:
 - a) Scott Vogt (ComEd)— Recovery of Electric Service Costs
 - b) Janice Dale (Illinois Attorney General’s Office)—Risk & Affordability in Electric Rates
 - c) Danny Waggoner (Advanced Energy Economy)—Capital Bias in Regulation and Emerging Methods to Mitigate it
 - d) Ken Costello (National Regulatory Research Institute)— Incentive Ratemaking
 - e) Bob Stevens (Illinois Industrial Energy Consumers)—Electrical Class Cost of Service Studies Review
 - f) Graeme Miller (Energy Resource Center)—Concerns with Cost Allocation for Combined Heat and Power Customers
- 3) General Discussion
- 4) Next Steps
- 5) Adjourn

Meeting Notes

Welcome & Introduction

- Meeting 3 & 4 will be scheduled from 9:00am-12:00pm CST
- Participants are invited to review Meeting 1 notes, and provide additional comments
- Ross Hemphill will provide a short summary of his meeting 1 comments

[Recovery of Electric Service Costs—Scott Vogt, ComEd]

- System statistics: 400+ municipalities in service territory, 5000+ transmission miles, 100,000+ Distribution miles, all time system peak was 23,753 MW hours
- Delivery statistics: 5441 Distribution feeders, 5MW 2017 average feeder peak, 27,316 MW 2017 sum of feeder peaks, 86,378 GWhs Delivered in 2017
- Energy Supply Statistics: 84 Alternative Retail Electric Suppliers (ARES), 215 municipalities have active municipal aggregation and are served by an ARES, ARES serve 70% of Delivered GWh in ComEd, and 33% of Residential Customers, ComEd has

2 supply options available to customers: 1. Blended (fixed rate for energy and capacity; default for non-muni Ag) 6,267 MW, or 2. Hourly (Locational Marginal Pricing (LMP) for energy, kW for capacity; default for C&I >100kW) 1,009 MW

- One of the few utilities that break residential classes between multi-family and single family
- When we talk about revenue requirement and rate design, it's important to remember—what revenue requirement are we talking about? For Delivery alone, we have:
 - Customer charge
 - Distribution facilities,
 - IL Distribution tax

Questions:

- Does Ameren operate using similar systems?
 - Yes, different exact numbers, but similar system
- When is this data available as of?
 - Updated as of May
- How frequently does ComEd provide data?
 - ComEd provides data to the ICC every month, not sure how ICC compiles data annually
- Do you have any community solar projects?
 - Not yet, expecting 120 by next year, but it's still very much in the development stage. We have storage on our system, but it's participating in the ancillary services market through Pennsylvania, Jersey, Maryland Power Pool (PJM)

[Risk and Affordability in Electric Rates—Janice Dale, Illinois Attorney General's Office]

- Electric usage has not been increasing, actual decrease in electric usage in past six years, even with proliferation of new electronic devices
- How have utilities responded to this reduced usage? Utilities have to a great extent, shifted risk to customers as a response, through
 - Formula rates,
 - Decoupling,
 - Variety of Riders in Illinois
 - including uncollectible adjustment rider which allows to collect excess bad debt from customers directly,
 - Energy Efficiency (EE) formula rate
 - Customers paying for Zero Emission Credits (ZECs)
 - Customer Choice Programs
 - 1.8 million IL customers getting supply through alternative providers, prior to choice, IL providers purchased electricity and had to use their expertise to choose best option—that risk has been shifted to customers

- Technology has created additional risks
 - Advanced Meter Infrastructure deployment
 - Microgrid pilots
- How does risk shifting affect affordability?
 - Paying for investments through riders means that people with the least information are responsible for the riskiest aspects of utility service
 - More fixed charges means conservation doesn't always help significantly
 - Residential heating customer disconnections have increased on average between 2013-2016
- Conclusions:
 - Customer choice is no substitute for affordability
 - Time of Use (TOU) pricing must be opt-in to avoid passing on risk to those unable to manage risk
 - Let cost causers pay for additional cost (e.g. Electric Vehicle (EV) charging)
 - Investment practices must be guided by least-cost utility ratemaking principles

Questions/ Comments:

- Is there prudence review as part of Illinois Commerce Commission (ICC) process?
 - Many of the elements in formula rates have been litigated and settled to the point where the review includes much less ICC discretion in how decisions are made. Formula is dictated by Illinois General Assembly, which is a change from how rates have been determined in the past
- Pilot programs—does the ICC approve these programs?
 - They do, sometimes the Cost-Benefit Analysis (CBA) is less rigorous than the AG's office thinks they should be. CBA should be data based, and not based on projections from other experiences
 - Not all pilots are brought to the ICC for approval. For example, with the microgrid docket—AG's office didn't think that docket was based on adequate CBA
 - Companies response—pilot programs going before the ICC should be determined to be to the benefit of the customers—if they're not benefitting the customer, they shouldn't be going to the pilot phase and funded by ratepayers
- There are both costs and benefits for shifting risks (ex: federal government supports a lot of research), places like ComEd have some of the lowest Return on Equity (ROE) because of this risk-shifting
 - AG response—30 year bond rate is at a historical low, it's not all about low ROE

- General Assembly decided that because of past reliability issues, it would be in the best interest of customers to require electricity providers to invest in distribution systems
- In terms of Cost-Benefits of Smart Meters—deployment is almost complete, but customers are not taking advantage of programs available to them through smart meters, so some of the enhanced services that were envisioned when the ICC approved smart meters haven't been realized yet
- Costs are avoidable to customers—if they reduce consumption to zero, then they won't pay for ZECs, or any other costs. If these customer choices were unavailable, customers wouldn't be able to save on these costs
- Any data on customer uptake on programs?
- Would Industrial Customers in the room want a Kilowatt hour (KWh) delivery charge?
 - Perception is that industrial customers don't want a KWh delivery charge

[Capital Bias in Regulation and Emerging Methods to Mitigate it—Danny Waggoner, Advanced Energy Economy]

- Return on Equity is set by regulators, Capital markets, and investor expectations/behaviors establish the cost of equity
- It is reasonable for utilities to have a modest incentive to invest in their systems
 - If $RoE > \text{market cost of equity}$ —new capital investments create shareholder value
 - If $RoE < \text{market cost of equity}$ —new capital investments destroy shareholder value
 - If $RoE = \text{market cost of equity}$ —Investments are made at costs
- Now that the grid is built out, capital bias can be counterproductive for system efficiency
- Capital solutions vs. service solutions
 - IT: servers, software and IT infrastructure vs. cloud computing
 - Transmission and Distribution (T&D): transformers, substations, etc. vs. Demand management, dispatch rights for Distributed Energy Resources (DER), etc.
- Regulatory capital bias can create a dilemma: a service solution can be better for customers but worse for utilities
- There are several options for overcoming this issue:
 - Treating the service solution as an Operation and Maintenance (O&M) expense
 - Allowing the utility to put the service solution in rate base,
 - Allowing the utility and customers to share in the savings
- Performance incentives can be used to counterbalance capital bias
 - Program-based: incentives for meeting metrics or program specific performance (peak time rebates, storage, Distributed Resources (DR))
 - System-wide: incentives for measurable reductions in system-wide peak demand
- Considerations for performance incentives:
 - System-wide metrics pose both challenges and benefits

- Allows for greater creativity
- Measurements and showing causality between reductions and utility actions can be difficult
- To be effective, incentive needs to result in net savings for customers but also to overcome a utility's opportunity cost

Questions / Comments

- Capital bias relates to O&M's "path to customers", this happened to ComEd with Energy Efficiency (EE)
- Transmission & Distribution—peak reduction: only 3% of ComEd feeders peak on system average
- Want to challenge the idea that incentives are the right answer. Regulatory compact assumes if you can justify cost in rate filing, those cost will be recoverable with a fair and reasonable return on capital costs. The idea that utilities need an incentive to do the right thing works to the detriment of the ratepayer. For example: utilities aren't pushing for cloud computing to be rate-based, but we have a docket for it, and utilities will use cloud computing. Sometimes incentives can create perverse incentives: EE statutes create annual goals: in Ameren's filing it indicated that it couldn't achieve the EE set by statute, ICC set goal below energy savings goal. Because Future Energy Jobs Act (FEJA) allows energy savings return above goals, advocates will have to watch reported savings closely for abuse.
- Have you looked at complexities when utility is affiliated with the generator?
 - New York (NY) utilities have financial separation, so that made it easier.
- If we were using rate design to send a price signal, would you do anything differently than if you were trying to reduce the sum of all the feeders vs. the system-wide peak? Is it technically feasible?
 - NY is trying to create locational price signals for locational peaks
 - Only looking at marginal benefits of exported energy. It's one way to do it.
 - When you're using rate design to reduce peak, you're sending a customer signal—doesn't get at the full picture because you're not sending the same signal to utilities
- Agree with presenter, in addition, this is part of the value stacking conversation that we're having in other NextGrid working groups. If you're looking at the value of an asset to a system, it depends on where it's at. Compensating for locational value is important.
- California (CA) is also looking at DG—amount compensated depends on the location of Distributed Resources (DR)

[Incentive Ratemaking—Ken Costello, National Regulatory Research Institute]

- Cost of Service Regulation -- a few main concerns:
 - Fixed base rates between general rate cases in spite of dynamic conditions

- Excessive regulatory lag jeopardizing a utility's financial health; for example, problems from delays in a utility's recovery of capital costs
- Regulatory lag deferring the benefits of utility efficiency gains to customers
- High regulatory costs; for example, frequent rate cases in a dynamic environment where the utility's average cost increases
- Weak incentives for long-term cost efficiency and innovation
- Utility discretion over the timing of rate cases
- Incentive for excessive capital investments
- Disincentive for utility-funded energy efficiency and distributed and energy resources
- There are many ways for regulators to improve utility performance:
 - Competition,
 - Performance Incentive Mechanisms (PIMs)
 - Performance standards
 - Retrospective Review
 - Prospective review
 - Performance-based regulation (PBR)
- PIMs & PBRs vs other approaches
 - Formula-based
 - Mitigates retrospective reviews
 - Utilities and consumers share the benefits and costs of utility performance deviating from a targeted or benchmark level
- What are PBRs and PIMs?
 - Ratemaking that explicitly allows utilities to recover certain costs based on their performance
 - Specifically, it sets utilities' revenues or shareholder earnings based on specific performance metrics
 - The intent, at least emphasized in recent efforts, is to give utilities stronger incentives to deliver value to customers and to advance certain public policy objectives
 - If you set a benchmark, and utilities deviate from the benchmark, then utilities cannot recover a full return on costs

Questions / Comments

- It's true that Price Cap Regulation was established for telephone, but it was also used for electric industry restructuring in England
- PBR requires fewer regulatory resources than our (U.S.) regulatory system

[Electrical Class Cost of Service Studies Review—Bob Stevens, Illinois Industrial Energy Consumers]

- Rate redesign proceeding occurs every 3 years in Illinois
- Embedded Cost of Service studies: based on accounting or “booked” cost, many different types of cost—tracked in standardized form, and cost are apportioned among classes based on the number of customers and their amounts and patters of usage
- Marginal cost studies: forward looking, based on change in cost due to providing an additional unit of service, apportioned among classes based on number of customers and load characteristics, and because utilities are allowed to collect their embedded costs, marginal cost must still be reconciled to revenue requirement.
- Step 1: Functionalization, typical categories include: production, transmission, distribution, customer accounts, administrative & general
- Step 2: Classification: Demand, energy, customer, direct assignment (cost attributable directly to a customer or class)
- Step 3: Allocation Factors: represent classes’ shares of classified costs. Generally Demand allocators are used for production, transmission and distribution. Generally Energy allocators for Fuel and other variable costs. Generally customer allocators for services and minimum distribution system
- Production and Transmission Demand Allocation Factors:
 - Demand—Coincident Peak¹ (CP) vs. Non-Coincident Peak² (NCP)
 - Based on class usage at generator, not at meter—losses must be considered
- Transmission Costs: fixed—do not vary with load, usually classified as demand-related
- Distribution Costs: Fixed—do not vary with load, classified as either demand-only (ICC), or demand/customer split (NARUC manual uses this method). Functionalization or allocation may be different for different voltage
 - Not all customers use all portions of distribution system—service at higher voltage does not utilize lower voltage parts of system
- Revenue allocation
 - Fairness and efficiency suggest that revenues should be collected in proportion to cost—thus, cost of service study results are key inputs
 - Other considerations:
 - Gradualism,
 - Avoidance of rate shock,
 - Cost study uncertainty

****note: questions and comments for Cost of Service Studies and Concerns with Cost Allocation for Combined Heat and Power Customers presentations found on page 9****

¹ The combined demand of a single customer or multiple customers at a single at a specific point in time or circumstance, relative to the peak demand of the system, in which “system” can refer to the aggregate load of a single utility or of multiple utilities in a geographic zone or interconnection, or some part thereof.

² NCP: non-coincident peak demand: the customer’s highest usage during the month, whenever it occurs.

[Concerns with Cost Allocation for Combined Heat and Power Customers— Graeme Miller, Energy Resource Center]

- The only distribution costs that are attributable to any particular customer are the meter and service drop, and billing costs
- Distribution infrastructure is sized to the combined loads of all customers—adding or losing customers doesn't change these costs
- Cost causation for standby is complex:
 - Coincident outages are likely drivers of standby costs, not sum of individual customers' generators
 - Use of standby service may not coincide with peak demand of the utility facility providing the service
 - Individual lines and feeders may have substantial excess capacity during coincident outages (so no incremental costs), or they may be fully utilized and facing upgrades in the near future (and this changes over time)
- There are also benefits:
 - Where delivery system is facing upgrades:
 - Distributed generation may allow deferrals, in which case benefits may offset costs
 - In some cases, these benefits may exceed costs
 - Real net costs may be negligible, negative or unknown
 - In some states public policy preference for less polluting energy sources is recognized as a benefit, so
 - cost-causer principles for standby services are complex
- There are also fair compensation considerations:
 - Value is a two (or more) way street
 - Consider all relevant sources of benefit and cost over the long term
 - Select and implement a valuation method
 - Cross-subsidies may flow either way
 - No more complicated than necessary
 - Support innovative power sector models
 - Keep incentive decisions separate from rate design
 - Keep decoupling decisions separate from rate design

Questions / Comments for last two presentations

- How localized could we design rate differentials to take advantage of the fact that ComEd's Grid is non-coincident?
 - Conceptually there may be something there, but it's incredibly difficult with current technology
- It seems like we're getting a distribution charge that's a full-service Distribution Charge that's a fixed charge every month—is this what's occurring?

- In the rates—seen on customer rates is an NCP customer charge. Every month, depending on your operational strategy, you can reduce it. Standard monthly charge for billing and metering as well that happens regardless of whether or not you're a cogeneration customer.
- It's not only a cogeneration issue. It's a base-load technology issue. As we go forward, have to consider how rates are structured, what are the costs. Cost causation on an as-use basis.
- While more people are trying to reduce grid-usage, why has no utility requested payment for standby service? [future topic]

Closing Remarks

- Next meeting—will spend some time updating chapter outline for Working Group 7