Regulation of Modernizing Power Distributors: Lessons From Performance-Based Regulation Research

Mark Newton Lowry, PhD
Pacific Economics Group Research, LLC
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Introduction

This presentation discusses the regulatory context for distribution (Dx) system modernization.

Traditional cost of service regulation (COSR) is stressed when distributors accelerate grid modernization.

This has sparked experimentation with new approaches to regulation which include performance based regulation (PBR) and distribution system planning.

Berkeley Lab has recently commissioned two papers on PBR.

This presentation considers implications for distribution regulation and planning.
Cost of Service Regulation

COSR Basics

• Base rates adjusted in rate cases that can be irregularly timed
• Tracker/rider treatment of fuel and purchased power expenses
• Usage (e.g., volumetric and demand) charges traditionally collect many “fixed” costs

Sensitivity to Business Conditions

• Utility performance and regulatory cost vary with external business conditions
• When conditions favor utilities, rate cases are infrequent so regulatory cost is low and performance incentives are strong
• When conditions are chronically unfavorable, rate cases are frequent so that regulatory cost is high, performance incentives are weakened, and operating flexibility is restricted
• Performance can deteriorate just when good performance is crucial
Drivers of Electric Utility Financial Attrition

<table>
<thead>
<tr>
<th>Multiyear Averages</th>
<th>Electricity Average Use</th>
<th>GDPPI Inflation $^2$</th>
<th>Summary Attrition Index</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Residential $^1$</td>
<td>Commercial $^1$</td>
<td>Average</td>
</tr>
<tr>
<td>1927-1930</td>
<td>7.06%</td>
<td>6.67%</td>
<td>6.86%</td>
</tr>
<tr>
<td>1931-1940</td>
<td>5.45%</td>
<td>2.00%</td>
<td>3.73%</td>
</tr>
<tr>
<td>1941-1950</td>
<td>6.48%</td>
<td>5.08%</td>
<td>5.78%</td>
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<tr>
<td>1951-1960</td>
<td>7.53%</td>
<td>6.29%</td>
<td>6.91%</td>
</tr>
<tr>
<td>1961-1967</td>
<td>5.37%</td>
<td>10.48%</td>
<td>7.93%</td>
</tr>
<tr>
<td>1968-1972</td>
<td>6.38%</td>
<td>6.43%</td>
<td>6.41%</td>
</tr>
<tr>
<td>1973-1982</td>
<td>1.34%</td>
<td>1.61%</td>
<td>1.47%</td>
</tr>
<tr>
<td>1983-1986</td>
<td>0.90%</td>
<td>2.26%</td>
<td>1.58%</td>
</tr>
<tr>
<td>1987-1990</td>
<td>1.39%</td>
<td>2.29%</td>
<td>1.84%</td>
</tr>
<tr>
<td>1991-2000</td>
<td>1.15%</td>
<td>1.68%</td>
<td>1.41%</td>
</tr>
<tr>
<td>2001-2007</td>
<td>0.73%</td>
<td>0.64%</td>
<td>0.68%</td>
</tr>
<tr>
<td>2008-2015</td>
<td>-0.47%</td>
<td>-0.20%</td>
<td>-0.34%</td>
</tr>
</tbody>
</table>


>>> Key business conditions today are much less favorable than in COSR’s “golden age” when it became a tradition.
Drivers of Electric Utility Financial Attrition (cont’d)

Capex Requirements

Many utilities today seek sustained high distribution capex
  - Replace aging facilities
  - Improve reliability and resiliency
  - Install “smart grid” facilities

This capex doesn’t automatically trigger new revenue

Attrition impact generally greater for utility distribution companies (UDCs) than for vertically integrated electric utilities (VIEUs)

UDCs are more likely to need several years of brisk rate escalation to quickly modernize grids
Utilities engaged in accelerated grid modernization are likely to request frequent rate cases under COSR today

Under this system . . .

- Little profit from capex containment
- Rate base growth is main path to earnings growth
- Weak incentive to embrace demand side management (DSM) and distributed generation and storage (DGS)

>>> Weak performance incentives while competition mounts
Review of Dx capex surges can be challenging

- Rapid technological change
- Shifting demand for distributor services due to DSM and DGS

>>> weak incentives + prudence concerns
  = benefit from distribution system planning

Grid modernization proceedings especially likely for UDCs

Frequent rate cases divert regulatory resources from other worthwhile activities
  (e.g., distribution system planning, generic rate design proceedings)
Alternative Regulation (Altreg)

COSR challenges have spurred adoption of alternative forms of regulation. These have various attributes:

- **Performance Incentives**
  - Low
  - Medium
  - High

- **Regulatory Cost**
  - Low
  - Medium
  - High

Some options address regulatory cost but not performance issues.

- COSR + Targeted PIMs
  - Low Power
  - High Power

- COSR + Capital Cost Tracker
  - Traditional
  - Incentivized

- Multiyear Rate Plans
  - Low Power
  - High Power

- Formula Rate Plans
- COSR + Planning
- COSR + Decoupling
Performance-Based Regulation

PBR: Regulation designed to improve utility performance with stronger incentives

3 established approaches (can be used in combination):

1. Targeted Performance Metrics and Incentive Mechanisms
2. Multiyear Rate Plans (MRPs)
3. Incentivized Cost Trackers
Performance Metrics

Performance metrics quantify utility activities in key performance areas

Several potential uses

- Monitoring Only
- Monitoring with Target
- Performance Incentive Mechanisms (PIMs)

PIMs strengthen incentives in targeted areas by linking revenue to performance

Performance metric systems can have different approaches for different metrics

“Scorecards” summarize utility performance for public
What do PIMs Target?

PIMs have traditionally targeted service quality and energy conservation.

Need for *new* performance metrics and incentive mechanisms focus of recent “utility of the future” proceedings.

Peak load management

- *System* load peak
- Non-wire alternatives to *local* grid investments

Functioning and utilization of smart-grid facilities

Quality of service to DGS customers

MRP practitioners (e.g., Britain, New York, Ontario) are also PIM innovators.
## Ontario Scorecard Metrics

### Performance Outcomes

**Customer Focus**
- Services are provided in a manner that responds to identified customer preferences.

### Operational Effectiveness

- Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.

### Performance Categories

#### Performance Categories

- **Service Quality**
  - New Residential/Small Business Services Connected on Time
  - Scheduled Appointments Met On Time
  - Telephone Calls Answered On Time
  - First Contact Resolution
  - Billing Accuracy
  - Customer Satisfaction Survey Results

- **Customer Satisfaction**

- **Safety**
  - Level of Public awareness [measure to be determined]
  - Level of Compliance with Ontario Regulation 22/04
  - Serious Electrical Incident Index
  - Number of General Public Incidents
  - Rate per 10, 100, 1000 km of line

- **System Reliability**
  - Average Number of Hours that Power to a Customer is Interrupted
  - Average Number of Times that Power to a Customer is Interrupted

- **Asset Management**
  - Distribution System Plan Implementation Progress

- **Cost Control**
  - Efficiency Assessment
  - Total Cost per Customer
  - Total Cost per Km of Line

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**Notes:**

1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor’s annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.
## Ontario Scorecard Categories (cont’d)

<table>
<thead>
<tr>
<th>Performance Outcomes</th>
<th>Performance Categories</th>
<th>Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Public Policy Responsiveness</td>
<td>Conserving &amp; Demand Management</td>
<td>Net Annual Peak Demand Savings (Percent of target achieved)</td>
</tr>
<tr>
<td>Distributors deliver on obligations mandated</td>
<td></td>
<td>Net Cumulative Energy Savings (Percent of target achieved)</td>
</tr>
<tr>
<td>by government (e.g., in legislation and in</td>
<td></td>
<td>Renewable Generation Connection Impact Assessments</td>
</tr>
<tr>
<td>regulatory requirements imposed further to</td>
<td></td>
<td>Completed On Time</td>
</tr>
<tr>
<td>Ministerial directives to the Board)</td>
<td></td>
<td>New Micro-embedded Generation Facilities Connected On Time</td>
</tr>
<tr>
<td></td>
<td><strong>Connection of Renewable Generation</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Financial Performance</strong></td>
<td><strong>Financial Ratios</strong></td>
<td>Liquidity: Current Ratio (Current Assets/Current Liabilities)</td>
</tr>
<tr>
<td>Financial viability is maintained; and savings</td>
<td></td>
<td>Leverage: Total Debt (includes short-term and long-term debt) to</td>
</tr>
<tr>
<td>from operational effectiveness are sustainable.</td>
<td></td>
<td>Equity Ratio</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Profitability: Regulatory Return on Equity</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Deemed (included in rates)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Achieved</td>
</tr>
</tbody>
</table>

### Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor’s annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.
PIM Pros and Cons

PIM Pro:

- Metrics focus utilities on performance dimensions that matter to regulators and customers
- PIMs can strengthen utility performance incentives
- PIMs can target specific areas of concern (e.g., areas of weak incentives)
- Sweeping change in regulatory system not required

PIM Con:

- Difficult to measure performance and design incentive mechanisms
- Design and operation of PIMs can invite controversy & strategic behavior
- Incremental regulatory cost can be non-negligible
- Utilities may focus on targeted performance areas and ignore less measurable areas
Multiyear Rate Plans

Key Components

• Reduced rate case frequency (e.g., 3-10 year rate case cycle)
• Attrition relief mechanism (ARM) provides automatic relief for cost pressures based on forecasts and/or an index --- not a cost tracker or “formula rate”
• Trackers for some costs (e.g., fuel, purchased power, and retirement)
• PIMs link earnings to reliability and customer service quality

Optional Components

• Revenue decoupling
• Earnings sharing and “off ramp” mechanisms
• Marketing flexibility (e.g., optional rates and services)
• Additional PIMs (e.g., demand-side management)
• Integrated resource planning and distribution system planning
MRP Precedents: Canada

MRPs mandatory for distributors in many Canadian provinces and countries overseas (e.g., Australia and RIIO in Great Britain)

Impetus has frequently come from policymakers
MRPs now a common form of Altreg in U.S.

Use of MRPs growing most rapidly for vertically integrated electric utilities (VIEUs)
Pro

Stronger performance incentives
Streamlined regulation
  Fewer, less overlapping rate cases free resources for other uses (e.g., Dx system planning)
Focus on performance (e.g., productivity goals and benchmarking)

Con

Change in regulatory system can be large
Parties can struggle to agree on key plan provisions (e.g., ARM)
Opportunities for strategic behavior
ARM Design

ARM design key issue in MRP proceedings

Several well-established approaches

- Forecasting (e.g., Minnesota)
- Indexing (e.g., Ontario)

\[ \text{growth Revenue} = \text{growth Input Prices} - X + \text{growth Customers} \]

\[ X \text{ Factor} = \text{Industry Productivity Trend} + \text{Stretch Factor} \]

Customers get productivity growth commitment

Stretch factors sometimes based on statistical benchmarking

- Hybrid (e.g., California)

\[ \text{e.g., indexing for O&M costs} \]
\[ \text{forecasting for capital} \]
Productivity index measures utility efficiency in using inputs (e.g., labor, materials and capital) to achieve operating scale.

Productivity grows when real (inflation-adjusted) cost grows more slowly than scale.

Berkeley Lab paper reports productivity trends of U.S. power distributors; here are 1996-2016 results.*

<table>
<thead>
<tr>
<th>Average Annual Growth Rate (1996-2016)</th>
<th>Capital</th>
<th>O&amp;M</th>
<th>Multi-factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>West North Central</td>
<td>0.41%</td>
<td>1.02%</td>
<td>0.62%</td>
</tr>
<tr>
<td>East North Central</td>
<td>-0.22%</td>
<td>0.38%</td>
<td>-0.18%</td>
</tr>
<tr>
<td>South Central</td>
<td>0.22%</td>
<td>0.62%</td>
<td>0.24%</td>
</tr>
<tr>
<td>Full U.S. Sample</td>
<td>0.29%</td>
<td>0.59%</td>
<td>0.34%</td>
</tr>
</tbody>
</table>

* Results for individual utilities in Additional Slides
Ontario Energy Board Uses Benchmarking to Set Stretch Factors for Power Distributors

VARIABLE KEY

Input Price: WK = Capital Price Index
Outputs: N = Number of Customers
C = System Capacity Peak Demand
D = Retail Deliveries

Other Business Conditions: L = Average Line Length (km)
NG = % of 2012 Customers added in the last 10 years
Trend = Time Trend

<table>
<thead>
<tr>
<th>EXPLANATORY VARIABLE</th>
<th>ESTIMATED COEFFICIENT</th>
<th>T-STATISTIC</th>
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</thead>
<tbody>
<tr>
<td>WK*</td>
<td>0.6271</td>
<td>85.5530</td>
</tr>
<tr>
<td>N*</td>
<td>0.4444</td>
<td>8.0730</td>
</tr>
<tr>
<td>C*</td>
<td>0.1612</td>
<td>3.2140</td>
</tr>
<tr>
<td>D*</td>
<td>0.1047</td>
<td>3.4010</td>
</tr>
<tr>
<td>L*</td>
<td>0.2853</td>
<td>13.9090</td>
</tr>
<tr>
<td>NG*</td>
<td>0.0165</td>
<td>2.4110</td>
</tr>
<tr>
<td>Trend*</td>
<td>0.0171</td>
<td>12.5700</td>
</tr>
<tr>
<td>Constant*</td>
<td>12.815</td>
<td>683.362</td>
</tr>
</tbody>
</table>

System Rbar-Squared = 0.983
Sample Period = 2002-2012
Number of Observations = 802

*Variable is significant at 95% confidence level

Benchmarking also used to appraise proposed revenue requirements in rate cases
Agreeing on ARMs for rapidly modernizing UDCs is difficult. This has slowed growth of MRPs for American UDCs. Some regulators (e.g., Alberta, Ontario, Britain) have grappled with challenge. ARMs are often easier to design for VIEUs.
PBR and planning are complements

PBR and planning can inform design of multiyear rate plan ARMs

- Enhances understanding of needed cost growth
- Distribution system plans required in some MRP systems

MRPs streamline regulation, free resources for planning

Metrics are a key planning tool

Productivity and benchmarking research used to design MRPs can also inform planning

- Index O&M expenses (e.g., Australia)
- Establish long run productivity goals
- Identify cost inefficiencies
- Australian, British & Ontario regulators use statistical cost research to appraise cost forecasts

Carrots and sticks work together to encourage better performance
Conclusions

Accelerated Dx system modernization weakens performance incentives and raises regulatory cost under COSR

Capital cost trackers and formula rates reduce regulatory cost but not prudence concerns

PBR and distribution system planning are increasingly used to address these challenges

Problems more pronounced for UDCs, so their regulators are leading innovators

PBR and planning are complements, using carrots and sticks to encourage better performance
Additional Slides
Capital Cost Tracker Precedents

Cost trackers are a common way to finance capex surges

Trackers in a few states track substantially all distribution capex

Source: Pacific Economics Group Research, LLC
Formula rates fund grid modernization in IL

Source: Pacific Economics Group Research, LLC
Electric Revenue Decoupling Precedents

Source: Pacific Economics Group Research, LLC
Marketing Flexibility

MRPs can afford utilities more marketing flexibility by reducing rate case frequency and opportunities for cross-subsidization

- e.g., “Streamlined regulation” of optional tariffs and services
  - Special contracts
  - Green power packages (utility scale and distributed)
  - Energy transformation services (e.g., EV charging, heat pump leasing)
  - Reliability-differentiated services
  - Other smart-grid-enabled services

MRPs have been popular in utility industries facing competition, technical change, and complex, changing demand
# Productivity Trends of Midwest and South Central Power Distributors (2007-2016)

<table>
<thead>
<tr>
<th>Company</th>
<th>TFP</th>
<th>O&amp;M PFP</th>
<th>Capital PFP</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>West North Central</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ALLETE (Minnesota Power)</td>
<td>0.68%</td>
<td>0.20%</td>
<td>1.02%</td>
</tr>
<tr>
<td>Cleco Power</td>
<td>1.44%</td>
<td>4.03%</td>
<td>-0.39%</td>
</tr>
<tr>
<td>Empire District Electric</td>
<td>-1.25%</td>
<td>-1.89%</td>
<td>-0.41%</td>
</tr>
<tr>
<td>Kansas City Power &amp; Light</td>
<td>0.89%</td>
<td>1.65%</td>
<td>0.42%</td>
</tr>
<tr>
<td>Kansas Gas and Electric</td>
<td>0.86%</td>
<td>0.58%</td>
<td>0.99%</td>
</tr>
<tr>
<td>MDU Resources</td>
<td>0.29%</td>
<td>1.08%</td>
<td>-1.09%</td>
</tr>
<tr>
<td>Northern States Power (MN)</td>
<td>1.78%</td>
<td>2.37%</td>
<td>1.43%</td>
</tr>
<tr>
<td>Northwestern Public Service (SD)</td>
<td>0.63%</td>
<td>0.66%</td>
<td>0.89%</td>
</tr>
<tr>
<td>Otter Tail Power</td>
<td>0.62%</td>
<td>0.27%</td>
<td>0.96%</td>
</tr>
<tr>
<td>Superior Water, Light and Power</td>
<td>-0.43%</td>
<td>-1.28%</td>
<td>-0.12%</td>
</tr>
<tr>
<td>Union Electric</td>
<td>1.28%</td>
<td>3.24%</td>
<td>0.28%</td>
</tr>
<tr>
<td>Westar Energy (KPL)</td>
<td>0.18%</td>
<td>0.11%</td>
<td>0.71%</td>
</tr>
<tr>
<td>Wisconsin Electric Power</td>
<td>0.34%</td>
<td>0.74%</td>
<td>0.79%</td>
</tr>
<tr>
<td>Wisconsin Power and Light</td>
<td>0.45%</td>
<td>1.70%</td>
<td>-0.71%</td>
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<tr>
<td>Wisconsin Public Service</td>
<td>1.50%</td>
<td>1.86%</td>
<td>1.44%</td>
</tr>
</tbody>
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Source: Pacific Economics Group Research, LLC
## Productivity Trends of Midwest and South Central Power Distributors (2007-2016) (cont’d)

<table>
<thead>
<tr>
<th></th>
<th>TFP</th>
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<th>Capital PFP</th>
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</thead>
<tbody>
<tr>
<td><strong>East North Central</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ameren Illinois</td>
<td>0.02%</td>
<td>-0.26%</td>
<td>0.21%</td>
</tr>
<tr>
<td>Cleveland Electric Illuminating</td>
<td>0.25%</td>
<td>2.25%</td>
<td>-0.59%</td>
</tr>
<tr>
<td>Dayton Power and Light</td>
<td>-0.83%</td>
<td>-0.63%</td>
<td>-0.76%</td>
</tr>
<tr>
<td>Duke Energy Indiana</td>
<td>0.70%</td>
<td>1.42%</td>
<td>0.75%</td>
</tr>
<tr>
<td>Duke Energy Ohio</td>
<td>0.28%</td>
<td>2.06%</td>
<td>-0.34%</td>
</tr>
<tr>
<td>Indiana Michigan Power</td>
<td>0.42%</td>
<td>1.96%</td>
<td>-0.85%</td>
</tr>
<tr>
<td>Indianapolis Power &amp; Light</td>
<td>0.95%</td>
<td>0.19%</td>
<td>1.41%</td>
</tr>
<tr>
<td>Ohio Edison</td>
<td>1.51%</td>
<td>4.26%</td>
<td>0.24%</td>
</tr>
<tr>
<td>Ohio Power</td>
<td>-2.94%</td>
<td>-5.54%</td>
<td>-0.90%</td>
</tr>
<tr>
<td>Southern Indiana Gas and Electric</td>
<td>-3.31%</td>
<td>-4.78%</td>
<td>-1.51%</td>
</tr>
<tr>
<td>Toledo Edison</td>
<td>0.99%</td>
<td>3.30%</td>
<td>-0.12%</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th></th>
<th>TFP</th>
<th>O&amp;M PFP</th>
<th>Capital PFP</th>
</tr>
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<tbody>
<tr>
<td><strong>South Central</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Duke Energy Kentucky</td>
<td>0.21%</td>
<td>0.12%</td>
<td>0.90%</td>
</tr>
<tr>
<td>Entergy Mississippi</td>
<td>1.14%</td>
<td>2.41%</td>
<td>-0.21%</td>
</tr>
<tr>
<td>Entergy New Orleans</td>
<td>4.85%</td>
<td>5.83%</td>
<td>5.62%</td>
</tr>
<tr>
<td>Kentucky Power</td>
<td>-2.22%</td>
<td>-3.08%</td>
<td>-1.10%</td>
</tr>
<tr>
<td>Kentucky Utilities</td>
<td>-1.19%</td>
<td>-1.67%</td>
<td>-0.32%</td>
</tr>
<tr>
<td>Kingsport Power</td>
<td>0.50%</td>
<td>2.08%</td>
<td>-0.24%</td>
</tr>
<tr>
<td>Louisville Gas and Electric</td>
<td>-1.42%</td>
<td>-2.24%</td>
<td>-0.58%</td>
</tr>
<tr>
<td>Mississippi Power</td>
<td>-0.48%</td>
<td>0.12%</td>
<td>-1.31%</td>
</tr>
<tr>
<td>El Paso Electric</td>
<td>0.78%</td>
<td>2.02%</td>
<td>-0.79%</td>
</tr>
</tbody>
</table>

**US Average**

```
<table>
<thead>
<tr>
<th>TFP</th>
<th>O&amp;M PFP</th>
<th>Capital PFP</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.34%</td>
<td>0.59%</td>
<td>0.29%</td>
</tr>
</tbody>
</table>
```
Case Study: Central Maine Power

Impetus for MRPs in Maine came from Commission 3 successive plans (here is the last)

Attrition Relief Mechanism:
growth Rates = growth GDPPI – X \ (X=1\%)

Capital Cost Tracker: Automated metering infrastructure

Earning Sharing: Asymmetric sharing of surplus earnings

Plan term: 5 years (2009-2013)

Service Quality: Multi-indicator penalty mechanism

Marketing Flexibility: Light-handed regulation of optional rate schedules and rate discounts

Distribution Productivity Trends of CMP and Two Northeast Regions

Source: Pacific Economics Group Research, LLC
Suggestions for Further Reading


Ken Costello, *Multiyear Rate Plans and the Public Interest*, National Regulatory Research Institute, 2016  

e21 Initiative (2016), Phase II Report *On implementing a framework for a 21st century electric system in Minnesota*, [www.betterenergy.org/e21-PhaseII](http://www.betterenergy.org/e21-PhaseII)


Suggestions for Further Reading (cont’d)

https://emp.lbl.gov/sites/all/files/lbnl-1004130_0.pdf

https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf


Mark Newton Lowry

President, Pacific Economics Group Research LLC (PEG)

• Active in PBR since 1990s
• Specialties: multi-year rate plans, productivity and benchmarking research, revenue decoupling and other Altreg mechanisms
• Recent clients: Alberta Utilities Consumer Advocate, Association Quebecoise des Consommateurs d’Electricite Industriels, Berkeley Lab, Commercial Energy Consumers of British Columbia, Edison Electric Institute, Green Mountain Power, Ontario Energy Board, Xcel Energy
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