Edison Electric Institute

Alternative Regulation for Evolving Utility Challenges:

An Updated Survey

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I. Introduction: The Problem of Financial Attrition Under Traditional Cost of Service Regulation

Many utilities are exploring alternatives to traditional rate regulation today. The underlying problem they face is a tendency of cost to grow more rapidly than the billing determinants (*e.g.* kWh of use) that determine revenue growth between rate cases. On the cost side, some utilities need large new generation or transmission investments. Others are engaged in accelerated distribution system modernization. Even without accelerated modernization, "wireco utilities" tend to experience more rate base growth than was the norm in the last years before they sold or spun off their generation. On the revenue side, growth in energy usage per customer ("average use") helped finance utility cost growth before 1980 because it bolstered revenue appreciably more than cost. Arguably, this was a feature of the Regulatory Compact which allowed utilities to finance needed new capacity.[1] Growth in average use has been much slower since then. Few utilities have experienced much bounceback in average use since the recession thanks to sluggish economic growth, increased energy efficiency, and the spread of distributed generation ("DG"). Some utilities are experiencing declining average use.

Traditional approaches to utility regulation can fail to provide timely rate relief for such conditions. The frequency of rate cases has increased. Utilities facing a pronounced gap between cost and billing determinant growth can experience chronic underearning even with annual rate cases. Financial attrition undoubtedly has been a factor in the long-term decline of average credit ratings among investor-owned electric utilities. This is illustrated in Figure 1. Higher risk raises financing costs and can discourage needed investments.

Alternative approaches to regulation have been developed which handle today's business conditions better. Some, such as multiyear rate plans, formula rates, and fully-forecasted test years, are comprehensive in character but involve large-scale departures from traditional regulation. Others, such as revenue decoupling and cost trackers, target cost and revenue problem areas that cause cost and revenue growth to differ. Judicious use of targeted approaches can bring revenue and cost growth into better balance and reduce the frequency of rate cases.

This survey, now updated to include precedents through late 2012, briefly explains salient alternative regulation ("Altreg") options and details precedents for electric and natural gas utilities. A summary of states that currently use these approaches is featured in Table 1. Natural gas precedents are included because of their relevance to "wires only" utilities.

[1] See Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation, by Karl McDermott, June 2012. Prepared for the Edison Electric Institute.

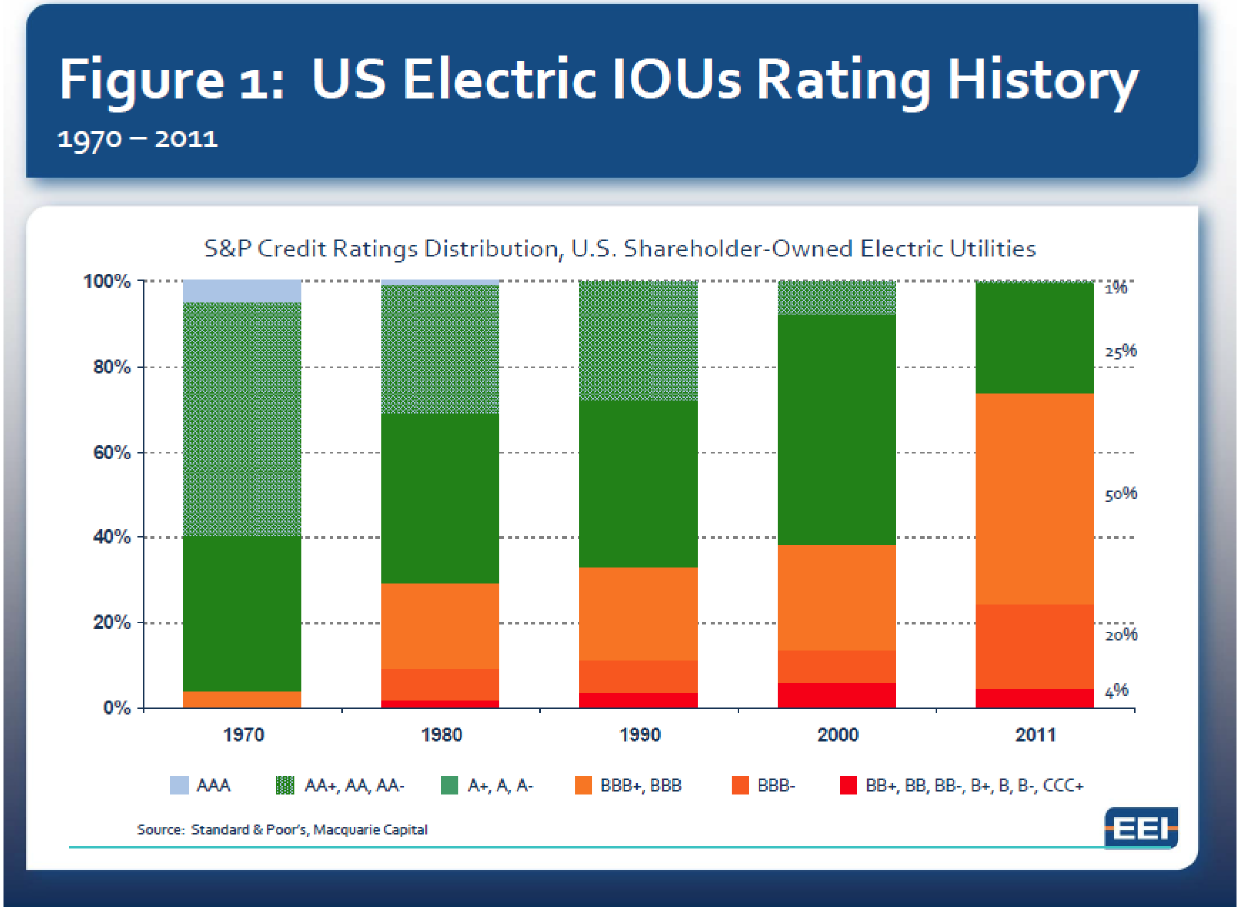


Figure 1: US Electric IOUs Rating History
1970 – 2011
S&P Credit Ratings Distribution, U.S. Shareholder-Owned Electric Utilities
100%
80%
60%
40%
20%
0%
1970
1980
1990
2000
2011
1%
25%
50%
20%
4%
AAA
AA+, AA, AA-
A+, A, A-
BBB+, BBB
BBB-
BB+, BB, BB-, B+, B, B-, CCC+
Source: Standard & Poor's, Macquarie Capital
EEI

Table 1
Innovations to Reduce Regulatory Lag: An Overview of Current Precedents

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Plan[2]	Revenue Decoupling			Retail Formula Rate Plans	Forward Test Years
				Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing		
Alabama	Yes						Yes	Yes
Arizona	Yes		Yes (electric only)	Yes (gas only)	Yes			
Arkansas	Yes			Yes (gas only)	Yes			
California	Yes		Yes	Yes				Yes
Colorado	Yes	Yes	Yes (electric only)					
Connecticut	Yes (electric only)			Yes (electric only)	Yes (gas only)	Yes		Yes
Delaware	Pending							
District of Columbia				Yes (electric only)				
Florida	Yes	Yes	Yes (electric only)			Yes (gas only)		Yes
Georgia	Yes	Yes	Yes (electric only)	Yes (gas only)		Yes (gas only)	Yes (gas only)	Yes
Hawaii	Yes (electric only)		Yes (electric only)	Yes (electric only)				Yes
Idaho				Yes (electric only)				
Illinois				Yes (gas only)		Yes	Yes (electric only)	Yes
Indiana	Yes (electric only)	Yes		Yes (gas only)	Yes (electric only)			
Iowa	Yes (electric only)		Yes (electric only)					
Kansas	Yes	Pending			Yes (electric only)			
Kentucky	Yes				Yes	Yes (gas only)		Yes
Louisiana	Yes (electric only)	Yes	Yes (electric only)		Yes (electric only)		Yes	Yes (electric only)
Maine	Yes (electric only)		Yes (electric only)					Yes
Maryland				Yes				
Massachusetts	Yes			Yes	Yes			
Michigan	Yes (gas only)	Pending		Yes (gas only)				Yes

Table 1 (continued)
Innovations to Reduce Regulatory Lag: An Overview of Current Precedent

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Cap[2]	Revenue Decoupling			Retail Formula Rate Plans	Forward Test Years
				Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing		
Minnesota	Yes	Yes		Yes (gas only)				Yes
Mississippi	Yes (electric only)	Yes				Yes (electric only)	Yes	Yes
Missouri	Yes (gas only)					Yes (gas only)		
Montana	Yes				Yes			
Nebraska								
Nevada				Yes (gas only)	Yes (electric only)			
New Hampshire	Yes		Yes (electric only)		Yes (electric only)			
New Jersey	Yes			Yes (gas only)				
New Mexico		Pending						Pending
New York	Yes (electric only)		Yes	Yes	Yes			Yes
North Carolina		Yes		Yes (gas only)	Yes (electric only)			
North Dakota		Pending				Yes (gas only)		Yes
Ohio	Yes	Pending	Yes (electric only)	Yes (electric only)	Yes (electric only)	Yes (gas only)		
Oklahoma	Yes (electric only)	Pending			Yes (electric only)	Yes (gas only)	Yes (gas only)	
Oregon	Yes			Yes	Yes			Yes
Pennsylvania	Yes (electric only)							Pending
Rhode Island	Yes			Yes				Yes
South Carolina	Yes (electric only)	Yes			Yes (electric only)		Yes (gas only)	
South Dakota	Yes (electric only)	Pending						
Tennessee				Yes (gas only)				Yes
Texas	Yes	Yes					Yes (gas only)	
Utah	Yes (gas only)			Yes (gas only)				Yes
Vermont	Yes (electric only)		Yes					
Virginia	Yes	Yes	Yes (electric only)	Yes (gas only)				
Washington	Pending			Yes (gas only)				
West Virginia	Yes (electric only)	Yes						
Wisconsin		Yes		Yes				Yes
Wyoming	Yes (electric only)	Yes		Yes (gas only)	Yes			Yes (electric only)

[1] This column pertains only to electric utilities.
[2] This column excludes plans involving rate freezes without extensive supplemental funding from trackers.

II. Cost Trackers and CWIP in Rate Base

A cost tracker is a mechanism for expedited recovery of specific utility costs. Balancing accounts are typically used to track unrecovered allowances. Cost recovery is often implemented using tariff sheet provisions called riders.

Trackers are used in various situations where they are a more practical means of adjusting rates for particular business conditions. Utilities usually recover fuel and purchased power costs via trackers because the volatility and substantial size of these costs would otherwise lead to frequent general rate cases and high risk. Other volatile expenses that are sometimes addressed using trackers include those for pension contributions and uncollectible bills.

A second common use of trackers is for costs that must be incurred because they are required by government agencies. Examples here include franchise fees and certain taxes. Tracking costs like these is fair to utilities and encourages government agents to moderate policies that are apt to raise customer bills.

Trackers are also widely used to compensate utilities for costs that are rapidly rising and don't produce much revenue, whether or not they are volatile or mandated. This can facilitate the targeted expenditures and reduce operating risk and rate case frequency. Examples of operation and maintenance ("O&M") expenses that are sometimes tracked due in whole or part to their rapid growth include those for health care and demand side management ("DSM").

Trackers for the costs of plant additions are sometimes called capital expenditure ("capex") trackers. The costs that are recovered typically include the accumulating depreciation, return on asset value, and taxes that the capex gives rise to. Recovery is sometimes achieved by keeping a rate case open beyond the date of a final decision for the limited purpose of adding assets to the revenue requirement.

Capex costs can qualify for expedited recovery using either or both of the second or third reasons just discussed. A utility might, for example, be compelled to make capital expenditures due to highway relocations or changes in government safety or reliability standards or conductor undergrounding requirements. Capex costs might also be tracked because they are large enough to cause material growth in assets that would otherwise occasion frequent rate cases.

The construction of base load generating capacity is a common source of major plant additions for VIEUs. This kind of capacity can take years to construct, especially when it is powered by solid fuels or hydroelectric resources. An allowance in rates for funds used during construction was traditionally not permitted until assets were used and useful and a rate case was filed. Deferred recovery can strain utility cash flow, involve extra financing expenses, and induce rate "shock" when the value of the plant and construction financing is finally added to the rate base. This is particularly true if the utility is not experiencing growth in average use during the years of construction. Many commissions address these problems by making a return on construction work in progress ("CWIP") eligible for immediate recovery. Capital cost trackers are often used in lieu of frequent rate cases to obtain CWIP recovery.

The capex costs of distribution system modernization are sometimes recovered using trackers for somewhat different reasons. The annual expenditure may not be as large as that for solid-fuel generation capacity, and construction of specific assets usually takes less than a year. However, the expenditures can still be sizable and, unlike new generation or customer connections, don't automatically trigger new revenue when construction is finished. A tracker for the cost of the new investment can help a company modernize its grid and improve its services without frequent rate cases.

The capex costs of generation emissions controls are often accorded expedited recovery for a combination of the reasons just discussed. The controls are occasioned by the emissions policies of state and federal agencies. Additionally, the facilities do not produce revenue and some facilities often become used and useful each year over a series of years.

There are varied treatments of costs in approved capex trackers. Plant addition budgets are usually set in advance and commission review of these budgets can be extensive. Once a budget is established, treatment of variances from the budget becomes an issue. Some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (*e.g.* 50-50) between the utility and its customers.

Recent precedents for capital cost trackers are listed in Table 2 and Figures 2 and 3. It can be seen that the precedents are quite numerous and continue to grow. This is one of the most widespread approaches to Altreg. On the electric side, trackers for emissions controls, generation capacity, and advanced metering infrastructure have been especially common in recent years. Trackers for gas utilities often focus on the cost of replacing old cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges ("DSICs"), are also common for accelerated modernization. Recent electric utility precedents for CWIP in rate base are listed in Table 3 and Figure 4. It can be seen that most involve investments in generating plant.

Figure 2: Recent Capex Tracker Precedents by State: Energy Utilities

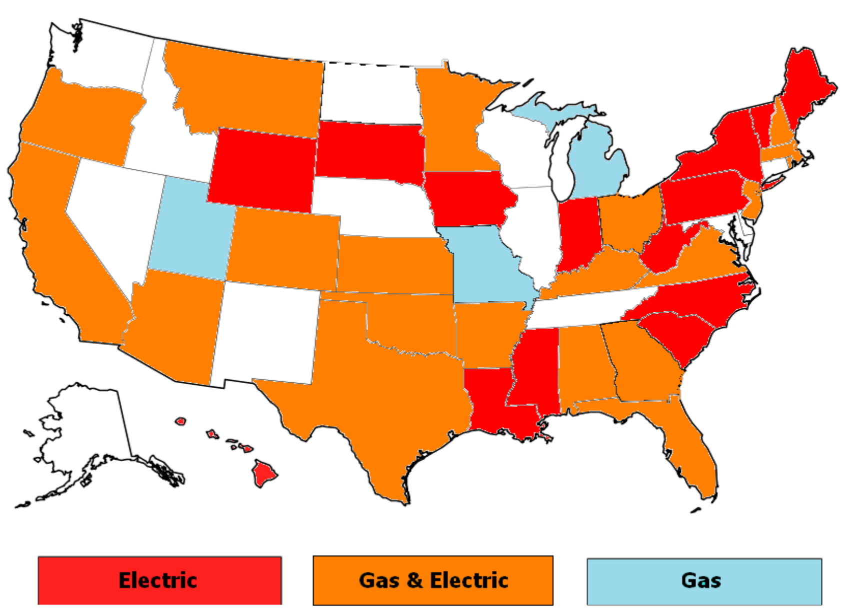


Table 2
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
Current					
AL	Alabama Power	Electric	Rate Certificated New Plant	Any approved by Commission through CPCN	Dockets 18117 and 18416 (November 1982)
AL	Mobile Gas Service	Gas	Cast Iron Replacement Factor	Replacement of cast iron mains	Docket 24794 (November 1995)
AR	CenterPoint Energy Arkla	Gas	Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
AR	CenterPoint Energy Arkla	Gas	Government Mandated Expenditure Surcharge Rider	Replacements resulting from highway and street rebuilding	Docket No. 10-108-U (March 2011)
AR	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Systemwide smart grid implementation	Docket No. 10-109-U (August 2011)
AR	SWEPCO	Electric	Generation Recovery Rider	New generation	Docket No. 09-008-U (November 2009)
AZ	Arizona Public Service	Electric	Environmental Improvement Surcharge	Environmental improvement projects	Docket No. E-01345A-11-024
AZ	Arizona Public Service	Electric	Renewable Energy Standard Adjustment Schedule	Renewables not recovered in base rates	Docket No. E-01345A-08-0172
AZ	Southwest Gas	Gas	Customer Owned Yard Line Cost Recovery Mechanism	Replacement and ownership of customer-owned yard lines that have been shown to be leaking	Docket No. G-01551A-10-0458 (January 2012)
CA	Pacific Gas & Electric	Electric & Gas	Smart Meter Balancing Accounts	AMI	Decision 06-07-027 (July 2006)
CA	Pacific Gas & Electric	Electric	Cornerstone Improvement Project Balancing Account	Capital and O&M expenses to improve the reliability of the electric distribution system	Decision 10-06-048 (June 2010)
CA	Pacific Gas & Electric	Gas Transmission	Pipeline Safety Implementation Plan	Pipeline replacement, automated valve installation, and upgrades to pipeline	Decision 12-12-030 (December 2012)
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 07-04-043 (April 2007)
CA	San Diego Gas & Electric	Electric	SONGS Major Additions Adjustment Clause	Steam generator replacement for San Onofre Nuclear Generating Station	Decision 06-11-026 (November 2006)
CA	Southern California Edison	Electric	Steam Generator Replacement Project	Steam generator replacement for San Onofre Nuclear Generating Station	Decision 05-12-040 (December 2005)
CA	Southern California Edison	Electric	SmartConnect Balancing Account	Advanced Metering Infrastructure Project	Decision No. 08-09-039 (September 2008)
CA	Southern California Edison	Electric	Solar PV Balancing Account	Solar generation	Decision No. 09-06-049 (June 2009)
CA	Southern California Gas	Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 10-04-027 (April 2010)
CO	Atmos Energy	Gas	AMI Surcharge	AMI pilot deployment	Docket No. 10A-189G (May 2010)
CO	Public Service Company of Colorado	Electric	Transmission Cost Adjustment	Transmission projects	Docket No. 07A-339E, Decision No. C07-1085 (December 2007)
CO	Public Service Company of Colorado	Gas	Pipeline Safety Integrity Adjustment	Gas distribution and transmission integrity management programs, main replacement, partial recovery of two large pipeline replacements	Docket No. 10-AL-963G (August 2011)
CT	Connecticut Light & Power	Electric	System Resiliency Plan	Structural hardening	Docket No. 12-07-06 (January 2013)
DE	All utilities may file	Electric & Gas	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	PSC Regulation Docket No. 63 (April 2012)
FL	Chesapeake Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket No. 120036-GU (September 2012)
FL	Florida Public Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket No. 120036-GU (September 2012)
FL	Gulf Power	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 930613-EI (January 1994)
FL	Florida Power and Light	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 080281-EI (August 2008)
FL	Florida Power and Light	Electric	Generation Base Rate Adjustment	Generation	Docket No. 120015-EI (December 2012)
FL	Florida Power and Light	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket No. 090009-EI (November 2009)
FL	Peoples Gas System	Gas	Cast Iron/Bare Steel Replacement Rider	Replacement of bare steel and cast iron pipes	Docket No. 110320-GU (September 2012)
FL	Progress Energy Florida	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket No. 090009-EI (November 2009)
FL	Progress Energy Florida	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 050078-EI (September 2005)
FL	Tampa Electric	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 960688-EI (August 1996)
GA	Atmos Energy	Gas	Pipe Replacement Surcharge	Replace cast iron and bare steel pipe	Docket No. 12509-U (December 2000)
GA	Atlanta Gas Light	Gas	Strategic Infrastructure Development and Enhancement Program	Infrastructure improvements that sustain reliability and operational flexibility	Docket No. 8516-U (October 2009)
GA	Georgia Power Company	Electric	Environmental Compliance Cost Recovery	Environmental	Docket No. 25060-U (December 2007)
GA	Georgia Power Company	Electric	Nuclear Construction Cost Recovery	Nuclear generation	Docket No. 27800, Senate Bill 31

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
HI	Hawaii Electric Light	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket No. 2007-0416 (December 2009)
HI	Hawaiian Electric Company	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket No. 2007-0416 (December 2009)
HI	Maui Electric	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket No. 2007-0416 (December 2009)
IA	MidAmerican Energy	Electric	Cooper Tracking Mechanism	Nuclear plant	Docket APP-96-1 (June 1997), Docket No. TF-02-154 (APP-96-1, RPU-96-8) (May 2002)
IN	Duke Energy Indiana	Electric	Qualified Pollution Control Property	Environmental	Cause No. 41744 (February 2001)
IN	Duke Energy Indiana	Electric	Integrated Coal Gasification Combined Cycle Generating Facility Cost Recovery Adjustment	Integrated gasification combined cycle generating plant	Docket No. 43114 (November 2007)
IN	Indianapolis Power & Light	Electric	Environmental Compliance Cost Recovery	Environmental	Cause 42170 (November 2002)
IN	Indiana Michigan Power	Electric	Clean Coal Technology Rider	Environmental	Cause No. 43636 (June 2009)
IN	Northern Indiana Public Service	Electric	Environmental Cost Recovery Mechanism	Environmental	Cause No. 42150 (November 2002)
KS	Atmos Energy	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No. 10-ATMG-133-TAR (December 2009)
KS	Black Hills Energy (Aquila)	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No. 07-AQLG-431-RTS (May 2007)
KS	Kansas Gas Service	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 10-KGSG-155-TAR (December 2009)
KS	Kansas Gas & Electric	Electric	Environmental Cost Recovery Rider	Environmental	Docket No. 05-WSEE-981-RTS (October 2005)
KS	Midwest Energy	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 09-MDWE-722-TAR (May 2009)
KS	Westar Energy Inc.	Electric	Environmental Cost Recovery Rider	Environmental	Docket No. 05-WSEE-981-RTS (October 2005)
KY	Atmos Energy	Gas	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocates	Docket No. 2009-00354 (May 2010)
KY	Columbia Gas	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 2009-00141 (September 2009)
KY	Delta Natural Gas	Gas	Pipe Replacement Program Surcharge	Replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations	Case No. 2010-00116 (October 2010)
KY	Kentucky Power	Electric	Environmental Cost Recovery Surcharge	Environmental	Docket No. 2002-00169 (March 2003)
KY	Kentucky Utilities	Electric	Environmental Cost Recovery Surcharge	Environmental	Case No. 93-465 (July 1994)
KY	Louisville Gas & Electric	Electric	Environmental Cost Recovery Surcharge	Environmental	Case No. 94-332 (April 1995)
KY	Louisville Gas & Electric	Gas	Gas Line Tracker	Replacement and transfer of ownership of customer owned service risers	Case No. 2012-00222 (December 2012)
LA	Cleco Power	Electric	Infrastructure and Incremental Costs Recovery	Generation, Transmission, environmental, other projects to be determined	Docket U-30689 (October 2010)
MA	Bay State Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel mains and services	DPU 09-30
MA	Massachusetts Electric	Electric	Net CapEx Factor	All distribution above depreciation expense	DPU 09-39
MA	Massachusetts Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Nantucket Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators	DPU 10-55
MA	New England Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of non-cathodically protected steel mains and services and small diameter cast-iron and wrought iron	DPU 10-114
MA	NSTAR Electric	Electric	Capital Projects Scheduling List	Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and manhole inspection, repair, and upgrade	DTE 05-85 and DPU 10-70-B
MA	NSTAR Electric	Electric	NA	Smart grid pilot	DPU-09-33
MA	Western Massachusetts Electric	Electric	Solar Program Cost Adjustment	Solar generation	DPU 09-05
MN	Minnesota Power	Electric	Arrowhead Regional Emission Abatement Rider	Environmental	M-05-1678 (June 2006)
MN	Minnesota Power	Electric	Renewable Resource Rider	Renewable generation	Docket M-10-273 (July 2010)
MN	Minnesota Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-07-965 (December 2007)
MN	Northern States Power (Xcel Energy)	Electric	Renewable Energy Standard Cost Recovery Rider	Renewable generation	M-07-872 (March 2008)
MN	Northern States Power (Xcel Energy)	Electric	Metropolitan Emissions Reduction Project (later called Environmental Improvement Rider)	Environmental	Docket M-02-633 (March 2004)
MN	Northern States Power (Xcel Energy)	Electric	Mercury Cost Recovery Rider	Environmental	Docket No. M-09-847 (November 2009)
MN	Northern States Power (Xcel Energy)	Gas	State Energy Policy Rider	Cast iron replacements	Docket No. M-08-261 (November 2008)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
ME	Central Maine Power	Electric	NA	AMI	Docket No. 2007-215(II) (February 2010)
MI	SEMCO Gas	Gas	Main Replacement Rider	Replacement of cast iron and unprotected steel mains and service lines	Case U-16169 (January 2011)
MO	AmerenUE	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components	Case No. GT-2008-0184 (February 2008)
MO	Atmos Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components	Docket No. GO-2009-0046 (October 2008)
MO	Laclede Gas	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components	Docket No. GR-2007-0208 (July 2007)
MO	Missouri Gas Energy	Gas	Infrastructure System Replacement Surcharge	Natural gas line replacements and relocations	Docket No. GR-2009-0355 (February 2010)
MS	Mississippi Power	Electric	Enviromental Compliance Overview Plan Rate	Environmental	Docket No. 92-UA-0058 and 92-UN-0059 (July 1992)
MT	Northwestern Energy	Electric	NA - Amounts recovered through electric supply service rates	Generation	Docket D.2008.6.69 (November 2008)
MT	Northwestern Energy	Gas	Natural Gas Supply Tracker	Battle Creek natural gas production resources	Docket No. D2012.3.25 (November 2012)
NH	Energy North	Gas	Cast Iron/Bare Steel Replacement Program	Replacement of cast iron and bare steel pipe	Docket DG-107 (June 2007)
NH	Granite State Electric	Electric	Reliability Enhancement Plan Capital Investment Allowance	Feeder hardening and asset replacement	Docket DG-107 (June 2007)
NH	Public Service Company of New Hampshire	Electric	Energy Service	Environmental	DE 11-250 (April 2012)
NJ	Elizabethtown Gas	Gas	Utility Infrastructure Enhancement Rate	Projects to enhance reliability and reinforce infrastructure	Docket No. GO09010053 (April 2009)
NJ	Elizabethtown Gas	Gas	Utility Infrastructure Enhancement Rate II	Projects to enhance reliability and reinforce infrastructure	Docket No. GO10120969 (May 2011)
NJ	New Jersey Natural Gas	Gas	Compressed Natural Gas Pilot Program	Compressed natural gas infrastructure	Docket No. GR11060361 (June 2012)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Docket No. GO09010050 (April 2009)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program II	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Docket No. EO11020088, GO10110862 (July 2011)
NJ	Public Service Electric and Gas	Electric	Solar Generation Investment Program	Solar generation	Docket No., EO09020125 (August 2009)
NJ	Rockland Electric	Electric	Smart Grid Surcharge	Smart Grid pilot	Docket No. EO09060459 (April 2010)
NJ	South Jersey Gas	Gas	Capital Investment Recovery Tracker	Bare steel replacement, expand key distribution mains for reliability	Docket No. GO09010051 (April 2009)
NJ	South Jersey Gas	Gas	Capital Investment Recovery Tracker II	Bare steel replacement, expand key distribution mains for reliability	Docket No. GO10100765 (March 2011)
NJ	South Jersey Gas	Gas	Capital Investment Recovery Tracker III	Accelerated Main Replacement Program	Docket No. GO11100632 (May 2012)
NY	Consolidated Edison	Electric	Monthly Adjustment Clause	AMI, SCADA, undergrounding	Case 09-E-0310 (October 2010)
OH	Cleveland Electric Illuminating	Electric	Rider AMI	Ohio Site Deployment	Case Nos. 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Cleveland Electric Illuminating	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case	Case No. 10-388-EL-SSO (August 2010)
OH	Columbia Gas of Ohio	Gas	Infrastructure Replacement Program Rider	Replacement of cast iron and bare steel mains & services, AMI	Case No. 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case No. 09-1036-GA-RDR (April 2010)
OH	Columbus Southern Power	Electric	Distribution Investment Rider	Net capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Columbus Southern Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case No. 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Dayton Power and Light	Electric	Environmental Investment Rider	Environmental	Case No. 05-276-EL-AIR (December 2005)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Pipeline Infrastructure Replacement Rider	Pipelines & faulty riser replacements	Case No. 09-458-GA-RDR (December 2009)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Automated Meter Reading Charge	AMI	Case No. 07-0829-GA-AIR, 07-0830-GA-ALT, 07-0831-GA-AAM, 08-0169-GA-ALT, and 06-1453-GA-UNC (October 2008); Case No. 09-38-GA-UNC (May 2009); Case No. 09-1875-GA-RDR (May 2010)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
OH	Duke Energy Ohio	Gas	Accelerated Main Replacement Program Rider	Replacement of bare steel and cast iron mains and services	Case No. 01-1228-GA-AIR, and 01-1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Gas	Advanced Utility Rider	Gas AMI	Case No. 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Electric	Infrastructure Modernization Distribution Rider	Electric AMI	Case No. 08-920-EL-SSO and 08-921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008)
OH	Ohio Edison	Electric	Rider AMI	Ohio Site Deployment	Case Nos. 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Ohio Edison	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Ohio Power	Electric	Distribution Investment Rider	Net capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Ohio Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case No. 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Toledo Edison	Electric	Rider AMI	Ohio Site Deployment	Case Nos. 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Toledo Edison	Electric	Delivery Capital Recovery Rider	Power Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Vectren Energy Delivery	Gas	Distribution Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Smart grid	Cause No. PUD 201000029 (July 2010)
OK	Oklahoma Gas & Electric	Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening	Cause No. PUD 20080387, Order No. 567670 (May 2009)
OK	Oklahoma Gas & Electric	Electric	Crossroads Rider	Crossroads Wind Farm	Cause No. PUD 201000037 (July 2010)
OK	Public Service Company of Oklahoma	Electric	Reliability Vegetation/Undergrounding Rider	Conversion of overhead to underground customer service lines	Cause No. PUD 200800144 (January 2009)
OR	Northwest Natural Gas	Gas	System Integrity Program	Bare steel replacement, Transmission integrity management program, distribution integrity management program	Docket UM 1406, Order No. 09-067 (March 2009)
OR	PacifiCorp	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
OR	PacifiCorp	Electric	NA	Mona to Oquirrh transmission line only if line is placed into service within 6 months of May 31, 2013	Docket UE 246, Order 12-493 (December 2012)
OR	Portland General Electric	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
PA	All utilities may file	Electric & Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects	Docket No. M-2012-2293611 (August 2012)
PA	PPL Electric Utilities	Electric	Act 129 Compliance Rider	AMI	Docket No. M-2009-2123945 (January 2010)
PA	PECO	Electric	Smart Meter Cost Recovery Rider	AMI	Docket No. M-2009-2123944 (April 2010)
PA	Metropolitan Edison	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Electric	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Duquesne Light	Electric	Smart Meter Charge Rider	AMI	Docket No. M-2009-2123948 (April 2010)
PA	West Penn Power	Electric	Smart Meter Surcharge	AMI	Docket No. M-2009-2123951 (June 2011)
RI	Narragansett Electric (electric operations)	Electric	Electric Infrastructure, Safety, and Reliability Plan Factor	Replacements and load growth	Docket No. 4218 (December 2011)
RI	Narragansett Electric (gas operations)	Gas	Gas Infrastructure, Safety, and Reliability Plan Factor	Replacement investment	Docket No. 4219 (September 2011)
SC	South Carolina Electric & Gas	Electric	NA	Nuclear generation	Docket 2008-196-E (March 2009)
SD	Black Hills Power	Electric	Environmental Improvement Adjustment tariff	Environmental	Docket EL11-001
SD	Northern States Power- MN	Electric	Environmental Cost Recovery Tariff	Environmental	Docket EL07-026 (January 2009)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
TX	All Electric Utilities	Electric	Distribution Cost Recovery Factor	Any distribution	Docket 39465
TX	AEP Texas Central	Electric	Advanced Metering System Surcharge	AMI	Docket No. 36928
TX	AEP Texas North	Electric	Advanced Metering System Surcharge	AMI	Docket No. 36928
TX	Atmos Energy Mid Tex	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy Pipelines	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy West Texas Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 9608
TX	Centerpoint Energy Entex - Houston Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 10067
TX	Centerpoint Energy Houston Electric	Electric	Advanced Metering System Surcharge	AMI	Docket No. 35620 (August 2008)
TX	Oncor Electric Delivery	Electric	Advanced Metering System Surcharge	AMI	Docket No. 35718 (August 2008)
TX	Texas-New Mexico Power	Electric	Advanced Metering System Surcharge	AMI	Docket No. 38306 (July 2011)
UT	Questar Gas	Gas	Infrastructure Rate Adjustment Tracker	Replacement of aging high-pressure feeder lines	Docket 09-057-16 (June 2010)
VA	Appalachian Power	Electric	Environmental & Reliability Cost Recovery Surcharge	Environmental & reliability	Docket No. PUE-2007-00069 (December 2007)
VA	Appalachian Power	Electric	Environmental Rate Adjustment Clause	Environmental	Case No. PUE-2011-00035 (November 2011)
VA	Appalachian Power	Electric	Generation Rate Adjustment Clause	Dresden plant	Docket No. PUE-2011-00036 (January 2012)
VA	Atmos Energy	Gas	Infrastructure Reliability and Replacement Adjustment	Replacement of first generation plastic pipe and service lines and bare steel mains and services	Case No. PUE-2012-00049 (August 2012)
VA	Columbia Gas of Virginia	Gas	SAVE Rider	Replacement of bare steel and cast iron mains, some early plastic pipe, isolated bare steel services, and risers prone to failure	Case No. PUE-2011-00049 (November 2011)
VA	Virginia Electric Power	Electric	Rider R	Bear Garden Generating Station	Case No. PUE-2009-00017 (March 2010)
VA	Virginia Electric Power	Electric	Rider S	Virginia City Hybrid Energy Center	Case No. PUE-2007-00066 (March 2008)
VA	Virginia Electric Power	Electric	Rider W	Warren County Power Station	Case No. PUE-2011-00042 (February 2012)
VA	Virginia Electric Power	Electric	Rider B	Biomass conversions	Case No. PUE-2011-00073 (March 2012)
VA	Washington Gas Light	Gas	SAVE Rider	Replacement of bare and unprotected steel services and mains, mechanically coupled pipe, copper services, cast iron main, and plastic services	Case No. PUE-2010-00087 (April 2011)
VT	Central Vermont Public Service	Electric	New Initiatives Adder	AMI	Dockets 7586 and 7612
WA	All gas utilities may file	Gas	Special Pipe Replacement Program Cost Recovery Mechanism	Replacement of pipe that is at an elevated risk of failure	Docket UG-120715 (December 2012)
WV	Appalachian Power	Electric	Construction/765kW Surcharge	Generation, Environmental	Case No. 11-0274-E-GI (June 2011)
WV	Wheeling Power	Electric	Construction/765kW Surcharge	Generation, Environmental	Case No. 11-0274-E-GI (June 2011)
WY	Black Hills Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket No. 20002-84-ET-12 (November 2012)
WY	Cheyenne Light, Fuel, & Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket No. 20003-123-ET-12 (November 2012)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
			Historic		
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Application 05-03-015 (March 2005)
CA	Southern California Edison	Electric	Advanced Metering Infrastructure Balancing Account	AMI	Docket No. 07-07-042 (July 2007)
CO	Public Service Company of Colorado	Electric	Air Quality Improvement Rider	Environmental	Docket 98A-511E
GA	Atlanta Gas Light	Gas	Pipeline Replacement Program Cost Recovery Rider	Replacement of cast iron and bare steel pipe	Docket 8516-U later updated in Docket No. 29950 as STRIDE tracker in 2009
IL	Commonwealth Edison	Electric	Rider Systems Modernization Projects, renamed Rider Advanced Metering Pilot	AMI	Case 07-0566, Case 09-0263
IL	Peoples Gas Light & Coke	Gas	Rider Incremental Cost Recovery	Replacement of cast iron and bare steel pipe	Docket No. 09-0167 (January 2010)
KY	Union Light, Heat and Power (Duke Energy Kentucky)	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 2001-00092 (January 2002)
NJ	Atlantic City Electric	Electric	Infrastructure Investment Surcharge	Replacements	Docket No. EO09010049 and GO09010054 (April 2009)
NJ	New Jersey Natural Gas	Gas	Accelerated Infrastructure Projects	Replace bare steel mains, reinforce distribution system & transmission mains	Docket No. GO09010052 and GR07110889 (April 2009)
NJ	New Jersey Natural Gas	Gas	Accelerated Infrastructure Projects II	Replace bare steel mains, reinforce distribution system & transmission mains	Docket No. GR10100793 (March 2011)
NY	Corning Natural Gas	Gas	Delivery Rate Adjustment	Incremental additions	Docket No. 08-G-1137 (March 2009)
NY	NYSEG	Gas	Gas Cost Savings Incentive Mechanism	Infrastructure that reduces the cost of gas supply	Docket No. 01-G-1668 (November 2002)
OH	Cleveland Electric Illuminating	Electric	Delivery Service Improvement Rider	Distribution reliability	0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Columbus Southern Power	Electric	IGCC Surcharge (Phase I only)	Early IGCC development	Case No. 05-376-EL-UNC (April 2006)
OH	Columbus Southern Power	Electric	IGCC Surchage (Phase II) IGCC Recovery Factor (Phase III)	IGCC	Case No. 05-376-EL-UNC (June 2006)
OH	Columbus Southern Power	Electric	Generation Cost Recovery Rider	Environmental	Case No. 07-63-EL-UNC (October 2007)
OH	Columbus Southern Power	Electric	Environmental Investment Carrying Charges (applies only to standard offer service customers)	Environmental	Case 08-917-EL-SSO (October 2011)
OH	Ohio Edison	Electric	Delivery Service Improvement Rider	Distribution reliability	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Ohio Power	Electric	Environmental Investment Carrying Charges (applies only to standard offer service customers)	Environmental	Case 08-917-EL-SSO (October 2011)
OH	Ohio Power	Electric	Generation Cost Recovery Rider	Environmental	Case No. 07-63-EL-UNC (October 2007)
OH	Ohio Power	Electric	IGCC Surcharge (Phase I only)	Early IGCC development	Case No. 05-376-EL-UNC (April 2006)
OH	Ohio Power	Electric	IGCC Surchage (Phase II) IGCC Recovery Factor (Phase III)	IGCC	Case No. 05-376-EL-UNC (June 2006)
OH	Toledo Edison	Electric	Delivery Service Improvement Rider	Distribution reliability	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OK	Empire District Electric	Electric	Capital Recovery Rider	All incremental investment between rate cases	Cause No. PUD 201000033, Order 577904 (August 2010)
OK	Oklahoma Gas & Electric	Electric	OU Spirit Rider	OU Spirit Wind Farm	Cause No. 200900167, Order No. 571788 (October 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Power Rider	Norman, Oklahoma pilot smart grid program	Cause No. 200800398
OK	Public Service Company of Oklahoma	Electric	Capital Investment Rider (CIR)	All incremental investment between rate cases	Cause No. 200900181 (August 2009)
OR	Northwest Natural Gas	Gas	NA	AMI	Docket UM 1413, Order 09-105 (March 2009)
OR	Northwest Natural Gas	Gas	Bare steel replacement program	Replacement of bare steel	Docket No. UM 1030, Order No. 01-843 (September 2001)
OR	Portland General Electric	Electric	NA	AMI	Docket UE 189, Order No. 08-245 (May 2008)
PA	PPL Electric Utilities	Electric	Energy Development Rider	Renewable interconnections	Docket No. M-00031715 F0003 (August 2006); Previously R-00973954 (May 14, 1998)
RI	Narragansett Electric (gas operations)	Gas	Accelerated Capital Replacement Program	Replacement of high pressure bare steel services inside customer premises	Docket No. 3943 (January 2009)
WV	Appalachian Power	Electric	NA: tracker included in the Expanded Net Energy Cost Mechanism	Transmission line, Environmental	Case No. 05-1278-E-PC-PW-42T (July 2006)

Figure 3: Recent Capex Tracker Precedents by State: Water Utilities

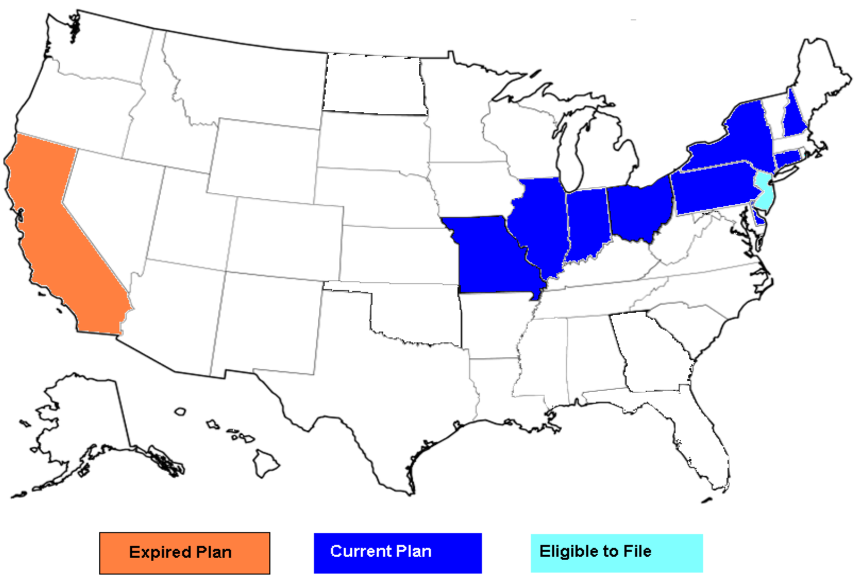


Figure 4: Recent Electric Precedents for CWIP In Rate Base

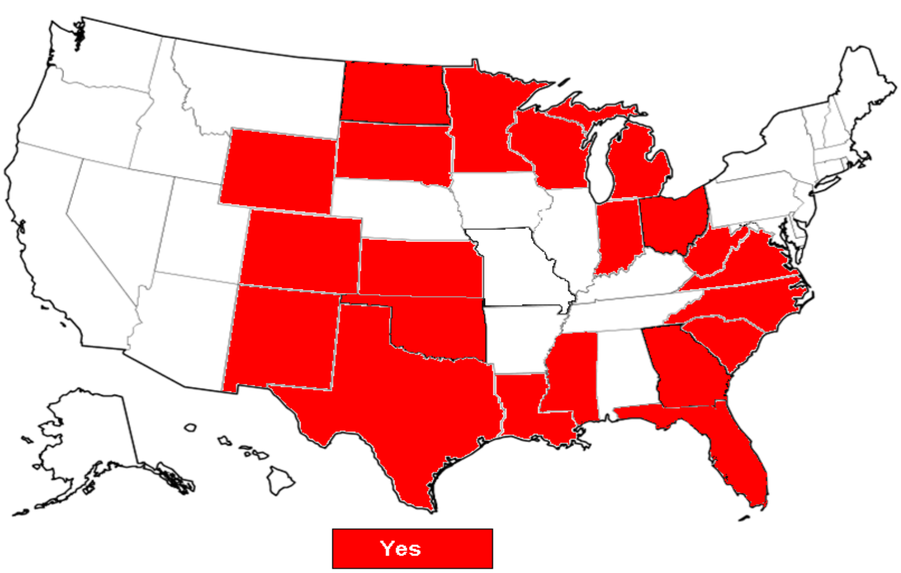


Table 3
CWIP in Rate Base: Recent Electric Retail Precedents

Jurisdiction	Company	Year Approved	Type of Project	Reference
Colorado	Public Service of Colorado	2006	Transmission, generation	Docket No. 06S-234EG
Colorado	Legislation	2007	Transmission	Senate Bill 07-100
Florida	Rulemaking	2007	Nuclear and IGCC generation	Docket 060508-EL
Florida	Florida Power & Light	2008	Nuclear generation	Docket 080650-EL
Florida	Progress Energy Florida	2008	Nuclear generation	Docket 080148-EI
Georgia	Georgia Power	2009	Nuclear generation	Docket 27800
Indiana	General Policy		Environmental	
Indiana	Duke Energy Indiana	2007	IGCC generation	Docket No. 43114
Kansas	Legislation	2008	Nuclear generation	Senate Bill 586
Louisiana	Rulemaking	2007	Nuclear generation	Docket R-29712
Louisiana	Cleco Power	2006	Generation	Docket U-28765
Michigan	Legislation	2008	Significant capital projects	House Bill 5524
Minnesota	Northern States Power- MN	2004	Environmental	Docket No. M-02-633
Minnesota	Minnesota Power	2007	Transmission	Docket M-07-965
Mississippi	Mississippi Power	2001	All projects within 1 year of completion	Docket No. 01-UN-0548
New Mexico	Legislation	2009	All	Senate Bill 477
North Carolina	Duke Energy Carolinas	2009	Generation	Docket No. E-7, Sub 909
North Carolina	Legislation	2007	Generation	Senate Bill 3
North Dakota	Legislation	2007	Transmission, federally mandated environmental	Senate Bill 2031 & House Bill 1221
Ohio	Legislation	2008	New Generation, Environmental	SB 221
Oklahoma	Legislation	2005	Environmental, transmission	House Bill 1910
South Carolina	South Carolina Electric & Gas	2003	Generation	Docket No. 2002-223-E
South Carolina	South Carolina Electric & Gas	2009	Nuclear generation	Docket 2009-211-E
South Dakota	Legislation	2006/2007	Transmission, environmental	
Texas	Rulemaking	2005	All Transmission within ERCOT (conditional)	Project 28884
Virginia	Legislation	2007	Reliability-related, nuclear, renewables, new generation using Virginia coal	Senate Bill 1416
Virginia	Virginia Electric Power	2008	New generation using Virginia coal	PUE-2007-00066
West Virginia	Appalachian Power	2006	Transmission, environmental, IGCC generation	Case No. 05-1278-E-PC-PW-42T
West Virginia	Monongahela Power	2007	Environmental	Case No. 05-0750-E-PC
Wisconsin	Wisconsin Public Service	2000	Nuclear generation, transmission	Docket 6690-UR-112
Wisconsin	Wisconsin Public Service	2005	Generation	Docket 6690-UR-117
Wisconsin	Wisconsin Power & Light	2012	All Commission approved projects	Docket 6680-UR-118
Wisconsin	General Policy		Diverse operations	
Wyoming	Black Hills Power	2012	Generation	Docket 20002-84-ET-12
Wyoming	Cheyenne Light, Fuel, & Power	2012	Generation	Docket 20003-123-ET-12

III. Revenue Decoupling

We use the term revenue decoupling to describe a diverse set of rate treatments designed to facilitate recovery of allowed revenue. The link between a utility's revenue and its sales is thereby weakened. This reduces the utility's disincentive to promote energy efficiency and can alleviate the financial stress caused by DSM programs and declining average use. DSM programs to encourage energy efficiency and discourage load peakedness can yield large cost savings for customers. Three approaches to decoupling are well established: decoupling true up plans, lost revenue adjustment mechanisms ("LRAMs"), and fixed variable pricing.

A. Decoupling True Up Plans

Decoupling true up plans adjust rates periodically to ensure that a utility's actual revenue tracks the revenue allowed by regulators. Most decoupling true up plans have two basic components: a revenue decoupling mechanism ("RDM") and an allowed revenue adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue and makes periodic true ups. To the extent that recovery of allowed revenue is achieved, utilities can use rate designs more aggressively to promote DSM goals.

Decoupling true ups may be made annually or more frequently. More frequent adjustments cause actual and allowed revenue each year to correlate better so that rates fluctuate less from year to year. The size of the true up that is permitted in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be recovered immediately.

RDMs vary in the scope of utility services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of distribution base rate revenue and are usually the primary focus of DSM programs. RDMs also vary in terms of the service classes for which revenues are pooled for true up purposes. In some plans all service classes are placed in the same "basket". Other plans have multiple baskets. These insulate customers of services in each basket from changes in demands for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between weather normalized revenue and allowed revenue. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism. Full decoupling provides more encouragement for rate design experimentation.

The RAM component of a decoupling true up plan escalates allowed revenue between rate cases. Virtually all decoupling true up plans have some kind of RAM because if allowed revenue is static the utility will experience financial attrition as its costs rise. Utilities that do not have RAMs in their decoupling true up plans often file annual rate cases.

Some RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. Broad-based RAMs are essentially the same thing as the revenue cap escalators that we discuss below in the section on multiyear rate plans. When RAMs are not broad-based, utilities usually retain the right to file rate cases during the decoupling plan and frequently do file. The revenue per customer ("RPC") freeze is a popular approach to RAM design. Allowed revenue grows at the same gradual pace as customer growth. An RPC freeze is not a broad-based RAM and will enhance expected revenue growth only when average use is expected to decline.

True up plans are the most popular approach to revenue decoupling in the United States. States that have tried gas and electric decoupling true up plans are indicated on the maps below in Figures 5a and 5b, respectively. Decoupling true up plan precedents in the United States and Canada are detailed in Table 4. It can be seen that there are more plans for gas utilities than for electric utilities. This reflects the fact that gas distributors have been much more likely to experience declining average use. Decoupling true up plans are nonetheless operative for a number of electric utilities in states with large DSM programs. Note also that RAMs for electric utilities are frequently broad-based, whereas most RAMs for gas distributors are revenue per customer freezes.

Figure 5a: Electric Decoupling True up Plans by State

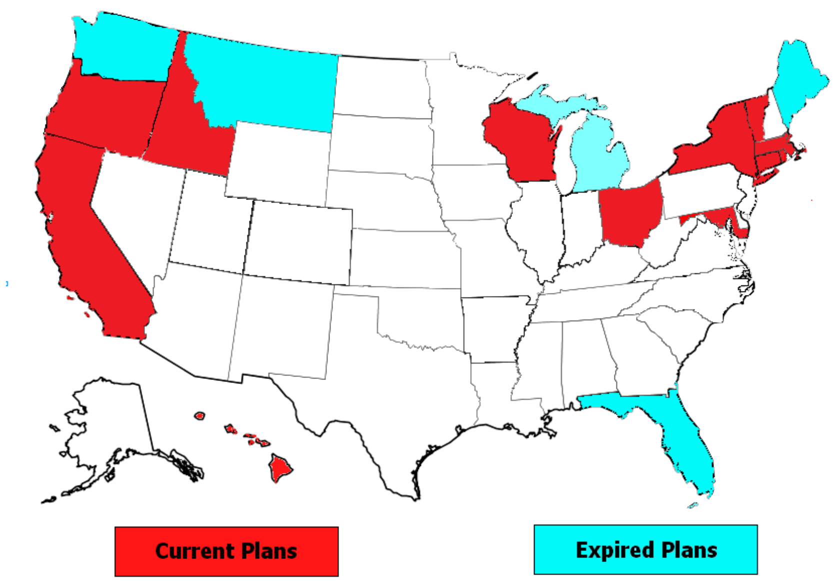


Figure 5b: Gas Decoupling True up Plans by State

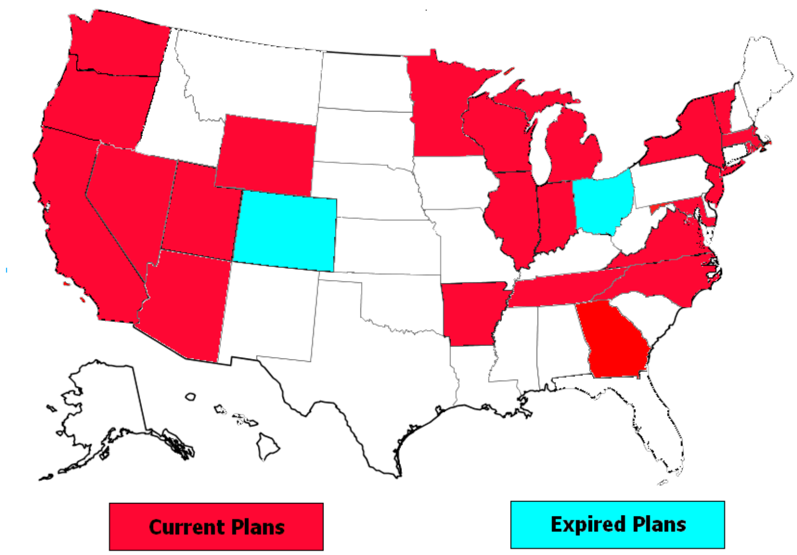


Table 4
Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
			Current		
Canada					
AB	Altagas Utilities	Gas	2013-2017	RPC Index	Decision 2012-237
AB	ATCO Gas	Gas	2013-2017	RPC Index	Decision 2012-237
BC	BC Hydro	Electric	2012-2014	Stairstep	Order G-77-12A
BC	FortisBC	Electric	2012-2013	Stairstep	Order G 110-12
BC	Terasen Gas	Gas	2012-2013	Stairstep	Order G-44-12
BC	Pacific Northern Gas	Gas	2003-open	RPC Freeze	N/A
ON	Union Gas	Gas	2008-2012, extended through 2013	RPC Index through 2012, RPC Freeze for 2013	Docket EB-2007-0606
United States					
AR	CenterPoint Energy	Gas	2008-2015	No RAM but broad-based capex tracker	Dockets 06-161-U, 11-088-U
AR	Arkansas Oklahoma Gas	Gas	2007-2013	No RAM	Dockets 07-026-U, 07-077-TF
AR	Arkansas Western	Gas	2007-2013	No RAM	Docket 07-078-TF
AZ	Southwest Gas	Gas	2012-open	RPC Freeze	Docket No. G-01551A-10-0458
CA	California Pacific Electric	Electric	2013-2015	Indexing	Decision 12-11-030
CA	Pacific Gas & Electric	Gas & Electric	2011-2013	Stairstep	Decision 11-05-018
CA	Southwest Gas	Gas	2009-2013	Stairstep	Decision 08-11-048
CA	Southern California Edison	Electric	2012-2014	Hybrid	Decision 12-11-051
CA	Southern California Gas	Gas	2008-2011	Stairstep	Decision 08-07-046
CA	San Diego Gas & Electric	Gas & Electric	2008-2011	Stairstep	Decision 08-07-046
CT	United Illuminating	Electric	2009-open	Stairstep until 2011/No RAM for 2011 onwards	Docket No. 08-07-04
DC	Potomac Electric Power	Electric	2010-open	RPC Freeze	Order 15556
GA	Atmos Energy	Gas	2012-open	No RAM but FRP type mechanism also in effect	Docket No. 34734
HI	Hawaiian Electric Company	Electric	2011-open	Hybrid	0083
HI	Hawaiian Electric Light Company	Electric	2012-open	Hybrid	Docket No. 2008-0274, 2009-
HI	Maui Electric	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0163
ID	Idaho Power	Electric	2012-open	RPC Freeze	Case No. IPC-E-11-19
IL	North Shore Gas	Gas	2012-open	No RAM	Case 11-0280
IL	Peoples Gas Light & Coke	Gas	2012-open	No RAM	Case 11-0281
IN	Indiana Gas	Gas	2011-2015	RPC Freeze	Cause No. 44019
IN	Vectren Southern Indiana	Gas	2011-2015	RPC Freeze	Cause No. 44019
IN	Citizens Gas	Gas	2007-open	RPC Freeze	Cause No. 42767
MA	Fitchburg Gas & Electric	Gas	2011-open	RPC Freeze	DPU 11-02
MA	Fitchburg Gas & Electric	Electric	2011-open	No RAM	DPU 11-01
MA	New England Gas	Gas	2011-open	RPC Freeze	DPU-10-114
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MA	Massachusetts Electric	Electric	2010-open	No RAM but broad-based capex tracker	DPU 09-39
MA	Bay State Gas	Gas	2009-open	RPC Freeze	DPU 09-30
MA	Boston-Essex Gas	Gas	2010-open	RPC Freeze	DPU 10-55
MA	Colonial Gas	Gas	2010-open	RPC Freeze	DPU 10-55
MD	Baltimore Gas & Electric	Electric	2008-open	RPC Freeze	Letter Orders ML 108069, 108061
MD	Delmarva Power & Light	Electric	2007-open	RPC Freeze	Order No. 81518
MD	Potomac Electric Power	Electric	2007-open	RPC Freeze	Order No. 81517
MD	Chesapeake Utilities	Gas	2006-open	RPC Freeze	Order No. 81054
MD	Washington Gas Light	Gas	2005-open	RPC Freeze	Order No. 80130
MD	Baltimore Gas & Electric	Gas	1998-open	RPC Freeze	Case No. 8780
MI	Michigan Consolidated Gas	Gas	2013-open	No RAM	Case No. U-16999
MI	Michigan Gas Utilities	Gas	2010-open	RPC Freeze	Case No. U-15990
MN	Minnesota Energy Resources	Gas	2012-2015	RPC Freeze	GR-10-977
MN	CenterPoint Energy	Gas	2010-2013	RPC Freeze	GR-08-1075
NC	Public Service Co of NC	Gas	2008-open	RPC Freeze	Docket No. G-5, Sub 495
NC	Piedmont Natural Gas	Gas	2008-open	RPC Freeze	Docket No. G-9, Sub 550
NJ	New Jersey Natural Gas	Gas	2010-2013	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2010-2013	RPC Freeze	Docket GR05121019
NV	Southwest Gas	Gas	2009-open	RPC Freeze	D-09-04003
NY	Orange & Rockland Utilities	Gas	2012-open	RPC Freeze	Case 08-G-1398
NY	Corning Natural Gas	Gas	2012-2015	RPC Stairstep	Case 11-G-0280
NY	Orange & Rockland Utilities	Electric	2012-2015	Stairstep	Case 11-E-0408
NY	Niagara Mohawk	Electric	2011-open	No RAM	Case 10-E-0050
NY	New York State Electric & Gas	Gas & Electric	2010-2013	RPC Stairstep for Gas, Stairstep for Electric	Case 09-E-0715
NY	Rochester Gas & Electric	Gas & Electric	2010-2013	RPC Stairstep for Gas, Stairstep for Electric	Case 09-E-0717

Table 4 (continued)
Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
NY	Consolidated Edison	Gas	2010-2013	RPC Stairstep	Case 09-G-0795
NY	Consolidated Edison	Electric	2010-2013	Stairstep	Case 09-E-0428
NY	Central Hudson G&E	Gas & Electric	2010-2013	RPC Stairstep for Gas, Stairstep for Electric	Case 09-E-0588
NY	Keyspan Energy Delivery - Long Island	Gas	2010-open	RPC Stairstep through 2012, RPC Freeze After 2012	Case 06-G-1186
NY	Keyspan Energy Delivery - New York	Gas	2010-open	RPC Stairstep through 2012, RPC Freeze After 2012	Case 06-G-1185
NY	Niagara Mohawk	Gas	2009-open	RPC Freeze	Case 08-G-0609
NY	National Fuel Gas	Gas	2008-open	RPC Freeze	Case 07-G-0141
OH	AEP Ohio	Electric	2012-2015	RPC Freeze	Case 11-351-EL-AIR
OH	Duke Energy Ohio	Electric	2012-2014	RPC Freeze	Case 11-5905-EL-RDR
OR	Northwest Natural Gas	Gas	2012-open	RPC Freeze	Order No. 12-408
OR	Portland General Electric	Electric	2011-2013	RPC Freeze	Order No. 10-478
OR	Cascade Natural Gas	Gas	2007-2012	RPC Freeze	Order No. 06-191
RI	Narragansett Electric	Electric	2012-open	No RAM but broad-based capex tracker	Docket 4206
RI	Narragansett Electric	Gas	2012-open	RPC Freeze	Docket 4206
TN	Chattanooga Gas	Gas	2010-2013	RPC Freeze	Docket 09-0183
UT	Questar Gas	Gas	2010-open	RPC Freeze	Docket No. 09-057-16
VA	Washington Gas Light	Gas	2010-2013	RPC Freeze	Case No. PUE-2009-00064
VA	Columbia Gas of Virginia	Gas	2013-2015	RPC Freeze	Case No. PUE-2012-00013
WA	Avista	Gas	2013-2014	Stairstep	Docket UG-120437
WI	Wisconsin Public Service	Gas & Electric	2013-open	No RAM	Docket 6690-UR-121
WY	Questar Gas	Gas	2012-open	RPC Freeze	Docket 30010-113-GR-11
WY	SourceGas Distribution	Gas	2011-open	RPC Freeze	Docket 30022-148-GR-10
			Historic		
Canada					
BC	BC Hydro	Electric	2011	No RAM	Order G-180-10
BC	BC Hydro	Electric	2009-2010	Stairstep	Order G-16-09
BC	Terasen Gas	Gas	2010-2011	Stairstep	Order G-141-09
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	BC Gas	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Gas	Gas	1998-2000	Hybrid	Order G-85-97
ON	Enbridge Gas Distribution	Gas	2008-2012	RPC Index	Docket EB-2007-0615
United States					
CA	Pacific Gas & Electric	Gas & Electric	2007-2010	Stairstep	Decision 07-03-044
CA	Pacific Gas & Electric	Gas & Electric	2004-2006	Indexing	Decision 04-05-055
CA	Pacific Gas & Electric	Gas & Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	Pacific Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93887
CA	Pacific Gas & Electric	Gas	1978-1981	No RAM	Decisions 89316, 91107
CA	PacifiCorp	Electric	1984-1985	Stairstep	Decision 89-09-034
CA	San Diego Gas & Electric	Gas & Electric	2005-2007	Indexing	Decision 05-03-025
CA	San Diego Gas & Electric	Gas & Electric	1994-1999	Hybrid	Decision 94-08-023
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	San Diego Gas & Electric	Gas & Electric	1986-1988	Hybrid	Decision 85-12-108
CA	San Diego Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93892
CA	Southern California Edison	Electric	2009-2011	Stairstep	Decision 09-03-025
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Southern California Edison	Electric	2001-2003	Indexing	Decision 02-04-055
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	Southern California Gas	Gas	2005-2007	Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	1998-2002	Indexing	Decision 97-07-054
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Southern California Gas	Gas	1981-1982	Stairstep	Decision 92497
CA	Southern California Gas	Gas	1979-1980	Stairstep	Decision 89710

Table 4 (continued)
Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
CO	Public Service Company of Colorado	Gas	2008-2011	RPC Freeze	Decision C07-0568
FL	Florida Power Corporation	Electric	1995-1997	RPC Freeze	Docket 930444
ID	Idaho Power	Electric	2007-2009	RPC Freeze	Case No. IPC-E-04-15
ID	Idaho Power	Electric	2010-2012	RPC Freeze	Case No. IPC-E-09-28
IL	North Shore Gas	Gas	2008-2012	RPC Freeze	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-2012	RPC Freeze	Case 07-0242
IN	Vectren Energy	Gas	2007-2011	RPC Freeze	Cause No. 43046
IN	Vectren Southern Indiana	Gas	2007-2011	RPC Freeze	Cause No. 43046
IN	Citizens Gas	Gas	2007-2011	RPC Freeze	Cause No. 42767
ME	Central Maine Power	Electric	1991-1993	RPC Freeze	Docket No. 90-085
MI	Consumers Energy	Electric	2009-2011	RPC Freeze	Case No. U-15645
MI	Consumers Energy	Gas	2010-2012	RPC Freeze	Case No. U-15986
MI	Detroit Edison	Electric	2010-2011	RPC Freeze	Case No. U-15768
MI	Upper Peninsula Power	Electric	2010-2011	RPC Freeze	Case No. U-15988
MI	Michigan Consolidated Gas	Gas	2010-2012	RPC Freeze	Case No. U-15985
MT	Montana Power Company	Electric	1994-1998	RPC Freeze	Docket No. 93.6.24
NC	Piedmont Natural Gas	Gas	2005-2008	RPC Freeze	Docket G-44 Sub 15
NJ	New Jersey Gas Natural	Gas	2007-2010	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	RPC Freeze	Docket GR05121019
NY	Central Hudson G&E	Gas	2009-open	RPC Freeze	Case 08-E-0888
NY	Central Hudson G&E	Electric	2009-open	No RAM	Case 08-E-0887
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Consolidated Edison	Gas	2007-2010	Stairstep	Case 06-G-1332
NY	Consolidated Edison	Electric	1992-1995	Stairstep	Opinion No. 92-8
NY	Long Island Lighting Company	Electric	1992-1994	Stairstep	Opinion No. 92-8
NY	New York State Electric & Gas	Electric	1993-1995	Stairstep	Opinion No. 93-22
NY	Niagara Mohawk	Electric	1990-1992	Stairstep	Case 94-E-0098
NY	Orange & Rockland Utilities	Gas	2009-2012	RPC Stairstep	Case 08-G-1398
NY	Orange & Rockland Utilities	Electric	2011-2012	No RAM	Case 10-E-0362
NY	Orange & Rockland Utilities	Electric	2008-2011	Stairstep	Case 07-E-0949
NY	Orange & Rockland Utilities	Electric	1991-1993	Stairstep	Case 89-E-175
NY	Rochester Gas & Electric	Electric	1993-1996	Stairstep	Opinion No. 93-19
OH	Vectren Energy	Gas	2007-2009	RPC Freeze	Case 05-1444-GA-UNC
OR	Northwest Natural Gas	Gas	2009-2012	RPC Freeze	Order No. 07-426
OR	Northwest Natural Gas	Gas	2005-2009	RPC Freeze	Order No. 05-934
OR	Northwest Natural Gas	Gas	2002-2005	RPC Freeze	Order No. 02-634
OR	PacifiCorp	Electric	1998-2001	Indexing	Order No. 98-191
OR	Portland General Electric	Electric	2009-2010	RPC Freeze	Order No. 09-020
OR	Portland General Electric	Electric	1995-1996	Stairstep	Order No. 95-0322
UT	Questar Gas	Gas	2006-2010	RPC Freeze	Docket No. 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	RPC Freeze	Case No. PUE-2008-00060
WA	Avista	Gas	2009-2012	RPC Freeze	Docket UG-060518
WA	Avista	Gas	2007-2009	RPC Freeze	Docket UG-060518
WA	Cascade Natural Gas	Gas	2005-2010	RPC Freeze	Docket UG-060256
WA	Puget Sound & Power	Electric	1991-1995	RPC Freeze	Docket UE-901184-P
WI	Wisconsin Public Service	Gas & Electric	2009-2012	RPC Freeze	D-6690-UR-119
WY	Questar Gas	Gas	2009-2012	RPC Freeze	Docket 30010-94-GR-08

B. Lost Revenue Adjustment Mechanisms

An LRAM explicitly compensates a utility for base rate revenues that are estimated to be lost due to its DSM programs, distributed generation ("DG"), or other specific causes. Compensation for lost margins is usually effected through a rate rider. Estimates of energy (and sometimes also peak load) savings are needed for LRAM calculations. The utility remains at risk for fluctuations in volumes and peak load due to weather, local economic activity, power market prices, and other volatile demand drivers. The utility is usually kept whole for the full revenue impact of its DSM (and possibly also DG) programs and not just for the incremental effort that causes average use to decline.[2] This is desirable because a program to promote DSM and DG increases the gap between cost and billing determinant growth and thereby increase potential attrition and the need for more frequent rate cases even if average use does not decline. Precedents for LRAMs are detailed in Table 5 and Figure 6 below.[3] It can be seen that, while LRAMs are less widely used than decoupling true up plans today, they have experienced a rebound in recent years and are more popular for electric than for gas utilities. For example, they are featured in Duke Energy's "Save a Watt" approach to DSM regulation and are also popular in the Intermountain West states. Some utilities have LRAMs and decoupling true up plans.

2 For an example of an LRAM that covers DG as well as DSM programs, see Decision 73183 of the Arizona Corporation Commission in the 2012 rate case for Arizona Public Service. A multiyear rate plan was also approved in the decision.

3 Some mechanisms similar to LRAMs are excluded from this survey.

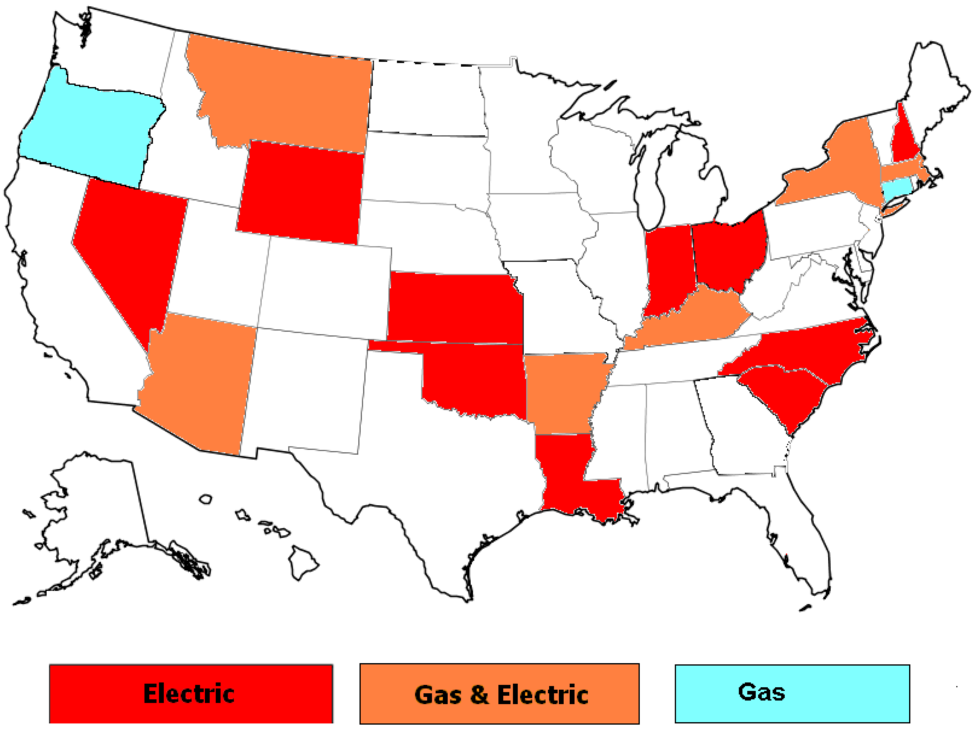
Table 5
Current LRAM Precedents

State	Company	Services	Approval Date	Case Reference
AR	Arkansas Oklahoma Gas	Gas	June 2011	Docket No. 07-077-TF, Order Number 30
AR	Centerpoint Energy Arkla	Gas	June 2011	Docket No. 07-081-TF, Order Number 31
AR	Entergy Arkansas	Electric	June 2011	Docket No. 07-085-TF, Order Number 40
AR	Oklahoma Gas & Electric	Electric	June 2011	Docket No. 07-075-TF, Order No. 26
AR	SourceGas Arkansas	Gas	June 2011	Docket No. 07-078-TF, Order No. 26
AR	Southwestern Electric Power	Electric	June 2011	Docket No. 07-082-TF, Order Nos. 35 and 36
AZ	Arizona Public Service	Electric	May 2012	Docket No. E-01345A-11-0224, Decision No. 73l83
AZ	UNS Gas	Gas	May 2012	Docket No. G-04204A-11-0158 Decision No. 73142
CT	Connecticut Natural Gas	Gas	August 1995	Docket No. 93-02-04
CT	Southern Connecticut Gas	Gas	August 1995	Docket No. 93-03-09
CT	Yankee Gas Service	Gas	January 2012	Docket No. 11-10-03
IN	Duke Energy Indiana (PSI)	Electric	February 2010	Cause No. 43374
IN	Indiana-Michigan Power	Electric	September 2010	Cause 43827
IN	Northern Indiana Public Service	Electric	May 2011	Cause 43618
IN	Southern Indiana Gas & Electric	Electric	August 2011 (large commercial and industrials), June 2012 (residential and small commercial)	Cause Nos. 43938 and 43405 DSMA 9 S1
KS	Kansas Gas & Electric	Electric	January 2011	Docket No. 10-WSEE-775-TAR
KS	Westar Energy	Electric	January 2011	Docket No. 10-WSEE-775-TAR
KY	Atmos Energy	Gas	September 2009	Case No. 2008-00499
KY	Columbia Gas of Kentucky	Gas	October 2009	Case No. 2009-00141
KY	Delta Natural Gas	Gas	July 2008	Docket No. 2008-00062
KY	Duke Energy Kentucky	Electric	December 1995 and February 2005	Case Nos. 95-321 and 2004-00389
KY	Duke Energy Kentucky	Gas	February 2005	Case No. 2004-00389
KY	Louisville Gas & Electric	Electric & Gas	November 1993	Case No. 93-150
KY	Kentucky Power	Electric	December 1995	Case No. 95-427
KY	Kentucky Utilities	Electric	May 2001	Case No. 2000-0459
LA	Entergy New Orleans	Electric	April 2009	New Orleans Resolution R-09-136
MA	All Electric distributors	Electric	July 2012	D.P.U. 12-01A
MA	Berkshire Gas	Gas	October 1992	D.P.U. 91-154
MA	NSTAR Electric	Electric	April 1992, June 1994, and June 2010	D.P.U. 90-335, D.P.U. 94-2/3-CC, and D.P.U. 10-06
MA	Commonwealth Gas d/b/a NSTAR Gas	Gas	November 1994	D.P.U. 94-128
MT	Northwestern Energy	Gas	February 2009	Docket No. D2008.5.44
MT	Northwestern Energy	Electric	December 2005	Docket No. D2004.6.90
MT	Montana-Dakota Utilities	Gas	October 2006	Docket No. D2005.10.156; Order No. 6697c

Table 5 (continued)
Current LRAM Precedents

State	Company	Services	Approval Date	Case Reference
NY	Central Hudson Gas & Electric	Electric	July 2006	Case No. 05-E-0934
NY	Consolidated Edison of New York	Electric	March 2005	Case No. 04-E-0572
NY	Consolidated Edison of New York	Gas	April 2002	Case No.00-G-1456
NY	Keyspan Long Island	Gas	December 2009	Case No. 06-G-1186; Currently effective for all customers not in RDM
NY	Keyspan New York	Gas	December 2009	Case No. 06-G-1185; Currently effective for all customers not in RDM
NC	Duke Energy Carolinas	Electric	February 2010	Docket No. E-7, Sub 831
NC	Progress Energy Carolinas (Carolina Power & Light)	Electric	November 2009	Docket No. E-2, Sub 931
NC	Virginia Electric Power	Electric	October 2011	Docket No. E-22, Sub 464
NH	Unitil Energy Services	Electric	June 2010	DE 09-137, Order No. 25,111
NV	Nevada Energy	Electric	May 2011	Docket 10-10024
NV	Sierra Pacific Power	Electric	May 2011	Docket 10-10025
OH	Duke Energy Ohio (Cincinnati Gas & Electric)	Electric	July 2007	Docket No. 06-0091-EL-UNC
OH	First Energy Ohio (Cleveland Electric Illuminating, Toledo Edison, Ohio Edison)	Electric	March 2009	Docket No. 08-935-EL-SSO
OH	American Electric Power (Ohio Power, Columbus Southern Power)	Electric	May 2010	Docket No. 09-1089-EL-POR; Effective for classes not included in RDM
OH	Dayton Power & Light	Electric	June 2009	Docket No. 08-1094-EL-SSO
OK	Empire District Electric	Electric	November 2009	Cause No. 200900146 Order 571326
OK	Oklahoma Gas & Electric	Electric	July 2008	Cause No. 200800059 Order 556179
OK	Public Service of Oklahoma	Electric	January 2010	Cause No. PUD 200900196; Order 572836
ON	Union Gas	Gas	January 2008	EB-2007-0606
ON	Enbridge Gas Distribution	Gas	February 2008	EB-2007-0615
ON	Toronto Hydro-Electric	Electric	September 2007	EB-2007-0096
OR	Portland General Electric	Electric	September 2001	Order No. 01-836; UE 79 (Approved 2001 LRAM) Currently non-residential customers only
OR	Cascade Natural Gas	Gas	April 2006	Order No. 06-191; UG 167 excludes classes under RDM
OR	Avista Utilities	Gas	December 1993	Order 93-1881
SC	Progress Energy Carolinas	Electric	June 2009	Docket No. 2008-251-E Order 2009-373
SC	Duke Energy Carolinas	Electric	January 2010	Docket No. 2009-226-E Order No. 2010-79
SC	South Carolina Electric & Gas	Electric	July 2010	Docket No. 2009-261-E, Order No. 2010-472
WY	Cheyenne Light, Fuel, and Power	Electric & Gas	September 2011	Docket Nos. 20003-108-EA-10 and 30005-140-GA-10
WY	Montana-Dakota Utilities	Electric	January 2007	Docket No. 20004-65-ET-06

Figure 6: Current LRAMs by State



C. Fixed Variable Pricing

Fixed variable pricing is an approach to the design of base rates that uses fixed charges (charges that do not vary with the sales volume or peak demand) to recover a high percentage of fixed costs. A *straight* fixed variable ("SFV") rate design recovers *all* fixed costs through fixed charges. A rate design that recovers a substantial but smaller share of fixed costs through fixed charges is sometimes called *modified* fixed variable pricing. Most fixed variable rate designs implemented to date have involved the same fixed charge for all customers in a service class. However, "sliding scale" rate designs have been developed which assign lower fixed charges to customers who are likely to have lower volumes.

The lion's share of base rate revenue from residential and commercial customers is typically raised using customer charges under fixed variable pricing. Revenue thus tends to grow at the gradual pace of customer growth.

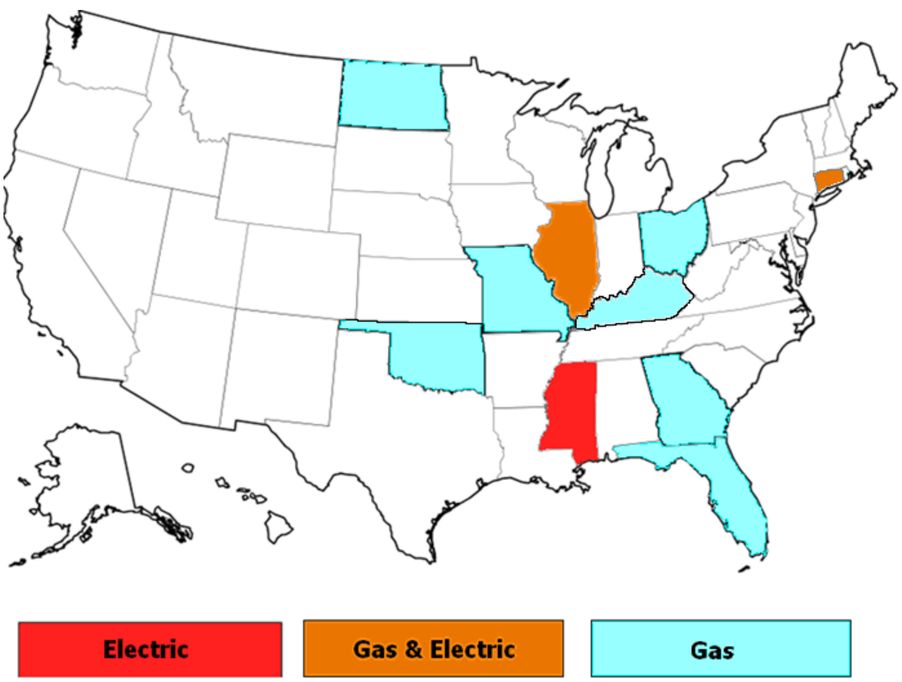
SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Precedents for fixed variable pricing in retail ratemaking are listed below on Table 6 and Figure 7. It can be seen that fixed variable retail pricing has to date been more common for gas distributors than electric utilities. This again reflects the greater problem of declining average use that gas distributors have faced. Ohio is noteworthy for having recently switched from decoupling true up plans to fixed variable pricing for its gas distributors.

Table 6
Fixed Variable Retail Pricing Precedents

Jurisdiction	Company Name	Services	Years in Place	Case Reference
CT	Connecticut Light & Power	Electric	2007-open	Docket 07-07-01
CT	Yankee Gas System	Gas	2011-open	Docket 10-12-02
FL	Peoples Gas System	Gas	2009-open	Docket 080318-GU
GA	Altanta Gas Light	Gas	1998-open	Docket No. 8390-U
IL	Ameren CILCO	Gas	2008-2012	Case 07-0588
IL	Ameren CIPS	Gas	2008-2012	Case 07-0589
IL	Ameren IP	Gas	2008-2012	Case 07-0590
IL	Ameren Illinois	Gas	2012-open	Case 11-0282
IL	Commonwealth Edison	Electric	2011-open	Case 10-0467
IL	Nicor Gas	Gas	2009-open	Docket No. 08-0363
IL	North Shore Gas	Gas	2008-open	Case No. 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-open	Case No. 07-0242
KY	Delta Natural Gas	Gas	2007-open	Case No. 2007-00089
KY	Duke Energy Kentucky	Gas	2010-open	Case No. 2009-00202
MO	AmerenUE	Gas	2007-open	Case No. GR-2007-0003
MO	Atmos Energy	Gas	2007-2010	Case GR-2006-0387
MO	Atmos Energy	Gas	2010-open	Case No. GR-2010-0192
MO	Empire District Gas	Gas	2010-open	Case GR-2009-0434
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MO	Laclede Gas	Gas	2002-open	Case GR-2002-356
MS	Mississippi Power	Electric	Occurred over period of years	No specific case
ND	Xcel Energy	Gas	2005-open	Case PU-04-578
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Case 07-1080-GA-AIR
OK	Oklahoma Natural Gas	Gas	2004-open	Cause Nos. PUD 200400610, PUD 201000048, PUD 200900110
OK	Centerpoint Energy	Gas	2010-open	Cause No. PUD 201000030

In addition to the precedents listed here, some other states have in recent years made sizable steps in the direction of fixed variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Investor-owned utilities in Canada are typically permitted to raise a much higher portion of their revenue through fixed charges than in the United States. Most fixed variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida, Georgia, and Oklahoma have fixed charges that vary in some fashion with long term consumption patterns.

Figure 7: Fixed Variable Pricing Precedents by State



IV. Forward Test Years

General rate cases involve "test years" in which revenue requirements and billing determinants are jointly considered in setting new rates. An historic test year ends before the rate case is filed. A fully-forecasted (a/k/a "forward") test year ("FTY") is a twelve month period that begins after the rate case is filed. An FTY typically begins about the time that the rate case is expected to end. Two-year forecasts are therefore required to span both the rate case year and the year that rates take effect.[4] In between FTYs and historic test years is the option of a "partially forecasted" test year in which some months of historic data on utility operations are combined with some months of forecasted data. Under this approach, actual data for all months usually become available during the course of the rate case.

Historic test years are chronically uncompensatory when cost grows materially faster than billing determinants. Annual rate cases can alleviate but not eliminate underearning. Where historic test years are used in rate cases there are thus added advantages to implementing other Altreg innovations discussed in this paper.

Forward test years can compensate utilities for a tendency of cost growth to exceed billing determinant growth.[5] If this tendency is chronic, however, it does not eliminate the problem of frequent rate cases. It is therefore not unusual for regulators to combine FTYs with other Altreg remedies, as is the case in California and New York.

Diverse approaches are used to forecast costs in FTY rate cases. Some companies rely on their budgeting process to make cost projections. Others normalized data for an historical reference period and adjust for known and measurable changes and then use indexing and other statistical methods to extend projections. Mixes of these two approaches are common.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s when rapid price inflation and major plant additions coincided with slowing growth in average use. This approach to Altreg was therefore one of the earliest implemented. Several additional states have recently moved in the direction of FTYs. Many of these states are in the West, where comparatively rapid economic growth has required more rapid build out of utility infrastructure. FTYs were recently sanctioned legislatively in Pennsylvania.

Current state policies concerning test years are summarized below in Figure 8 and Table 7. The ranks of US jurisdictions that allow the use of alternatives to historic test years have swollen and now encompass well over half of the total. The "other" category in Figure 8 includes states where utilities can file FTYs but many do not (*e.g.* Illinois), states where FTYs may be approved on a case by case basis (*e.g.* New Mexico, Utah, and Wyoming), and states where partially forecasted test years are the norm (*e.g.* Ohio and New Jersey). Forward test years are the norm in Canada and several jurisdictions have permitted two forward test years.

[4] A forward test year can be the rate case year, and thereby not require two-year forecasts, if rates are allowed to be changed as proposed on an interim basis shortly after the filing.

[5] The effect on credit metrics can be material. For evidence see "Forward Test Years for US Electric Utilities" by Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos, August 2010. Prepared for the Edison Electric Institute.

Figure 8: Test Year Policy by State

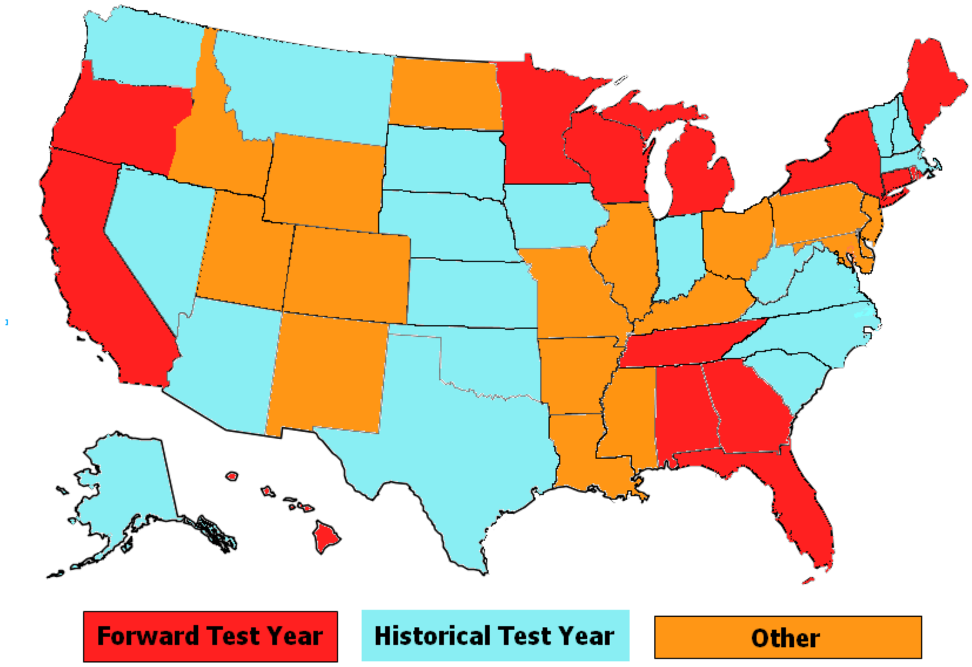


Table 7
Test Year Approaches of US Jurisdictions

Jurisdiction	Notes
Fully-Forecasted (15)	
Alabama	Utilities operate under forward-looking formula rate plans
California	
Connecticut	
FERC	Rate cases use forward test years but some formula rate plans use HTYs
Florida	
Georgia	
Hawaii	
Maine	
Michigan	
Minnesota	
New York	
Oregon	
Rhode Island	
Tennessee	
Wisconsin	
Partially-Forecasted (3)	
Arkansas	
Ohio	
New Jersey	
Transitional/Varying (14)	
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently
Delaware	Before restructuring FTY filings were common, but companies have used a mix of HTYs and partially-forecasted test years in recent filings
Idaho	
Illinois	Utilities use various test years including FTYs
Kentucky	Utilities use various test years including FTYs
Louisiana	Utilities use various test years including FTYs
Maryland	Utilities use various test years excluding FTYs
Mississippi	One electric utility operates under a forward-looking formula rate plan
Missouri	Utilities have the option to file partially-forecasted test years
New Mexico	A recently passed law allows for use of FTYs, but no rate increase based on FTY evidence has yet been approved
North Dakota	Utilities use various test years including FTYs
Pennsylvania	Partially-forecasted test years have been the norm. Law allowing fully-forecasted test years passed in 2012. First FTY case is pending.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently used FTYs
Historic (20)	
Alaska	
Arizona	
Colorado	Utilities can file FTY evidence. No FTY rates have yet been approved but a recent case made extraordinary HTY adjustments.
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs. Gas companies are legally authorized to use FTYs but commonly use HTYs.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

V. Multiyear Rate Plans

Multiyear rate plans ("MRPs") are designed to compensate a utility for changing business conditions without frequent, full true ups to its actual cost of service. Rate cases are held infrequently, most often at three to five year intervals. Any rate escalations that are made between rate cases are based in whole or in part on automatic attrition relief mechanisms ("ARMs"). The rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth. The "externalization" of ratemaking that these two features of MRPs achieve can strengthen utility performance incentives despite a reduction in regulatory cost. Benefits of better performance can be shared between the utility and its customers. Lower regulatory cost has special appeal in jurisdictions where numerous utilities must be regulated.

ARMs typically cap the growth in either rates (*e.g.* customer charges and cents per kWh) or allowed revenue. Rate caps are favored when and where utilities are encouraged to bolster system use since they strengthen incentives to promote use and facilitate marketing flexibility by reducing concerns about cross-subsidies. Revenue caps are usually combined with decoupling true ups, and are often favored where utilities must cope with declining average use and/or large-scale DSM programs.

Several approaches to the design of ARMs are well-established. These approaches include stairsteps, indexing, and hybrids. Stairsteps provide predetermined increases in rates (or revenue) which often reflect forecasts of cost growth. Indexing escalates rates (or revenue) automatically for inflation and sometimes also for growth in the number of customers served and/or industry productivity trends. Hybrid ARMs typically involve indexing of budgets for O&M expenses and stairsteps for capital cost budgets.

The indexing approach to ARM design is more common for distribution charges because distribution cost growth is relatively gradual and predictable. Hybrid and stairstep ARMs are more adaptable to the cost growth trajectories of VIEUs, which are more uneven due to occasional major plant additions. Some VIEUs operating under MRPs have separate ratemaking treatments for generation and distribution.

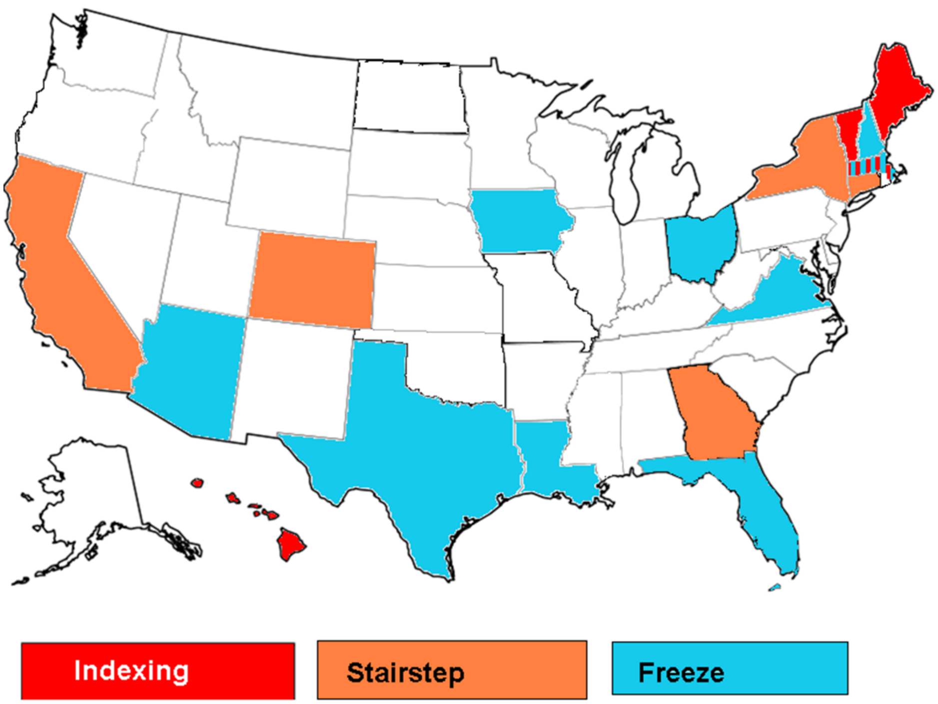
Supplemental rate adjustments are usually allowed for changes in business conditions that are especially difficult to address using ARMs. A tracker that recovers a large portion of a utility's capex cost can, for example, sometimes permit the company to operate under a multiyear freeze on rates for other non-energy costs. This is so because the value of the residual rate base is more likely to be static or decline. Trackers may also address *force majeure* events such as severe storms and changes in tax rates and other government policies that affect costs.

Some multiyear rate and revenue caps feature earnings sharing mechanisms ("ESMs") that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Some feature "off-ramps" that permit plan suspension when earnings are unusually high or low. Plans often feature award and/or penalty mechanisms that are linked to the utility's service quality.

MRPs were first widely used in the railroad, telecommunications, and oil pipeline industries. A major attraction was the ability of price caps to afford utilities flexibility in serving markets with diverse competitive pressures from a consolidated set of assets. The use of MRPs in the regulation of gas and electric utilities has been chiefly motivated by other advantages such as stronger performance incentives and lower regulatory cost.

Current US and Canadian precedents for MRPs are indicated in Table 8 and Figures 9a and 9b.[6] In the US, multiyear rate plans are most common in California and the Northeast. MRPs with ARMs that escalate rate or revenue automatically are more common for energy distributors than for VIEUs. Canada is moving towards MRPs with index-based ARMs for pipe and wire utilities in all four populous provinces. MRPs with index-based ARMs are more the rule than the exception for pipe and wire utilities overseas. ARMs used in MRPs for VIEUs typically have a stairstep or hybrid form. Other VIEUs operate under a combination of a rate freeze and one or more trackers to compensate the utility for specific causes of potential attrition.

Figure 9a: Recent US Electric Multiyear Rate Cap Precedents by State



[6] The table considers only MRPs that weren't listed in Table 4 on decoupling true up precedents. Figures 9a and 9b cover all MRPs. Rate freezes without extensive supplemental funding from trackers are excluded from Table 8 and Figures 9a and 9b.

Table 8
Multiyear Price Cap Precedents[1,2]

Jurisdiction	Company Name	Plan Term	Services Covered	Rate Escalation Provisions	Case Reference
Current					
AZ	Arizona Public Service	2012-2016	Bundled power service	Rate freeze with an adjustment to account for purchase of SCE's share of Four Corners generating facility, additional capex and other cost trackers, LRAM	Decision No. 73183, May 2012
CA	PacifiCorp	2011-2013	Bundled power service	Price Cap Index: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; supplemental funding for major plant additions can be requested in annual filings.	Decision 10-09-010; September 2, 2010
CO	Public Service Company of Colorado	2012-2014	Bundled power service	Stairstep	Decision No. C12-0494
FL	Florida Power & Light	2013-2016	Bundled power service	Rate freeze with multiple capex and other cost trackers	Docket No. 120015-EI, December 2012
FL	Progress Energy Florida	2012-2016	Bundled power service	Rate Freeze with one step plus capex and other cost trackers	Docket No. 120022-EI
GA	Georgia Power	2011-2013	Bundled power service	Stairstep: Rate increases permitted for DSM and major generation plant additions	Docket 31958
IA	MidAmerican Energy	2001 - 2005, extended to 2013	Bundled power service	Rate Freeze with nuclear capex and other cost trackers	Dockets RPU-01-3 and RPU-2012-0001
LA	Cleco	2009-2014	Bundled power service	Rate freeze with capex tracker	Order No. U-30689
ME	Central Maine Power (III)	2009-2013	Power distribution	Price Cap Index: GDPPI - 1%, separate AMI tracker	Docket 2007-215
NH	Public Service Company of New Hampshire	2010-2015	Power distribution (generation regulated separately)	Stairstep: Rate increases allowed to account for distribution capital additions in 2010-2013	DE 09-035
NH	Unitil Energy Systems	2011-2016	Power distribution	Stairstep: Rate increases allowed to account for distribution capital additions in 2011-2013	DE 10-055
OH	AEP-OH	2012-2015	Power distribution	Rate Freeze supplemented by capex and other cost trackers	Case No. 11-346-EL-SSO, August 8, 2012
OH	First Energy Ohio	2011-2014, later extended to 2016	Power distribution	Rate Freeze with capex and other cost trackers	Case Nos. 11-388-EL-SSO, 12-1230-EL-SSO
VA	Virginia Electric Power	2010-2013	Bundled power service	Rate Freeze with capex and other cost trackers	Case No. PUE-2009-00019
VT	Green Mountain Power	2010-2013	Electric	Revenue cap index	Docket No. 7585
VT	Central Vermont Public Service	2011-2013	Electric	Revenue cap index	Docket No. 7627
VT	Vermont Gas Systems	2012-2015	Gas	Revenue cap hybrid	Docket No. 7803
Alberta	Enmax	2007-2013	Power distribution	Price Cap Index: Input Price Index -1.2%	Decision 2009-035
Alberta	Altagas Utilities	2013-2017	Gas	Revenue Per Customer Indexing: Input Price Index - 1.16%, separate capex trackers	Decision 2012-237
Alberta	ATCO Gas	2013-2017	Gas	Revenue Per Customer Indexing: Input Price Index - 1.16%, separate capex trackers	Decision 2012-237
Alberta	EPCOR, Fortis Alberta	2013-2017	Power distribution	Price Cap Index: Input Price Index - 1.16%, separate capex trackers	Decision 2012-237
Northwest Territories	Northland Utilities	2011-2013	Bundled power service	Stairstep	Decision 17-2011
Northwest Territories	Northland Utilities (Yellowknife)	2011-2013	Bundled power service	Stairstep	Decision 13-2011

Table 8 (continued)
Multiyear Price Cap Precedents[1,2]

Current

Jurisdiction	Company Name	Plan Term	Services Covered	Rate Escalation Provisions	Case Reference
Ontario	All Ontario distributors	2010-2013	Power distribution	Price Cap Index: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies)	EB-2007-0673 (July 14, 2008, September 17, 2008, and January 28, 2009)
Prince Edward Island	Maritime Electric	2013-2016	Bundled power service	Stairstep: Bill defines rates for each year.	Bill 26 (2012) Electric Power (Energy Accord Continuation) Amendment Act

Historic

Jurisdiction	Company Name	Plan Term	Services Covered	Attrition Relief Mechanisms	Case Reference
CA	Sierra Pacific Power	2009-2011, extended to 2012	Bundled power service	Price Cap Index	Decision 09-10-041
CA	PacifiCorp	1994-1996, extended to 1999	Bundled power service	Price Cap Index	Decision 93-12-106; December 3, 1993
CA	PacifiCorp	2007-2009, extended to 2010	Bundled power service	Price Cap Index	Decisions 06-12-011 and 09-04-017
CA	San Diego Gas and Electric	1999-2002	Electric & Gas	Price Cap Index	Decision 99-05-030; May 13, 1999
CA	Southern California Edison	1997-2001	Electric	Price Cap Index	Decision 96-09-092; September 6, 1996
CT	United Illuminating	2006-2008	Power Distribution	Stairstep	Docket 05-06-04
FL	Florida Power & Light	2006-2009	Bundled power service	Rate Freeze with exception for new generating facilities after they are in service and multiple capex and other cost trackers	Docket 050045-EI
FL	Progress Energy Florida	2006-2009	Bundled power service	Rate freeze with 1 step to reflect generation brought in-service and multiple capex and other cost trackers	Docket No. 050078-EI
GA	Atlanta Gas Light	2005-2010	Gas distribution	Base rate freeze featuring a broad-based capex tracker	Docket No. 18638-U
MA	Bay State Gas	2006-2009	Gas distribution	Price Cap Index	Docket DTE 05-27
MA	Berkshire Gas	2002-2012	Gas distribution	No adjustment until September 2004, then Price Cap Index	Docket D.T.E. 01-56
MA	Boston Gas (I)	1997-2001	Gas distribution	Price Cap Index	Docket D.P.U. 96-50-C (Phase I) May 16, 1997
MA	Boston Gas (II)	2004-2010	Gas distribution	Price Cap Index	Docket DTE 03-40
MA	Blackstone Gas	November 1, 2004 - October 31, 2009	Gas distribution	Price Cap Index	Docket D.T.E. 04-79
MA	National Grid	2000-2010	Power distribution	Rate Freeze between 2000 and 2005, Price Cap Index: 2006-2010, inflation adjustment made based on index of regional power distribution charges.	Docket DTE 99-47 (November 29, 1999)
MA	Nstar	2006-2012	Power distribution	Price Cap Index	Docket D.T.E. 05-85
ME	Bangor Gas	2000-2009, extended to 2012	Gas Distribution	Price Cap Index	Docket 970795 (June 26, 1998)
ME	Bangor Hydro Electric (I)	1998-2000	Power distribution	Price Cap Index	Docket 97-116 (March 24, 1998)
ME	Bangor Hydro Electric (II)	2002-2007	Power Distribution	Stairstep	Docket No. 2001-410
ME	Central Maine Power (I)	1995-1999	Bundled power service	Price Cap Index	Docket 92-345 Phase II (January 10, 1995)
ME	Central Maine Power (II)	2001-2007	Power distribution	Price Cap Index	Docket 99-666 (November 16, 2000)

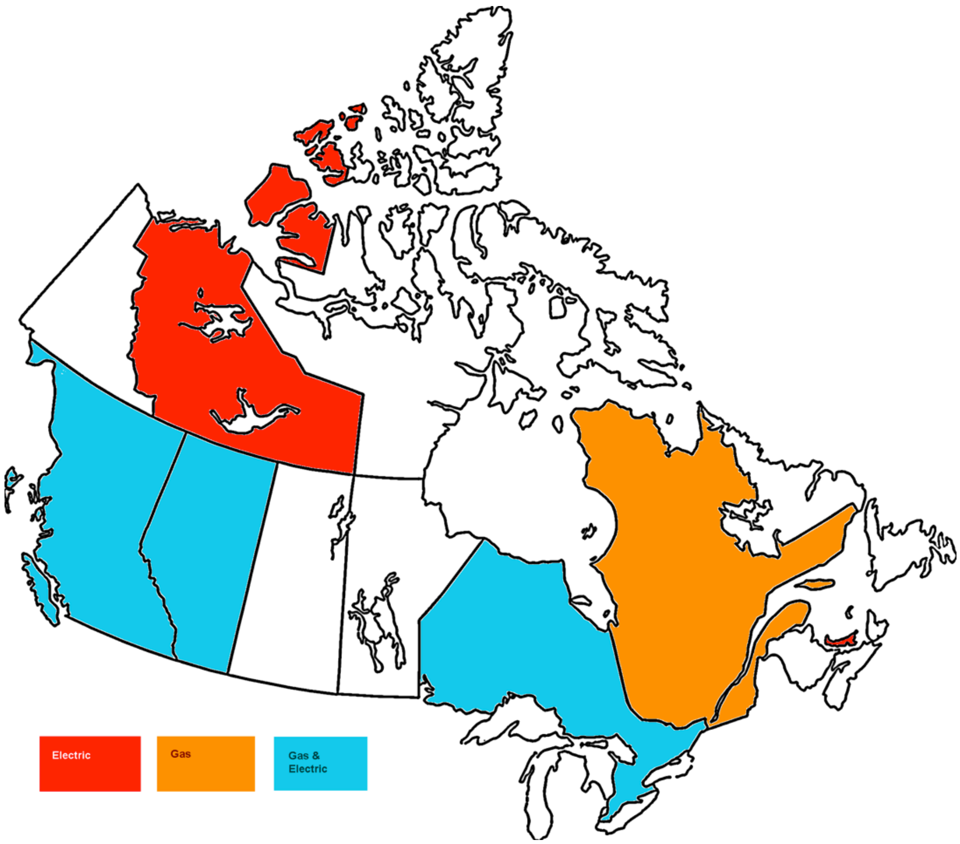
Table 8 (continued)
Multiyear Price Cap Precedents[1,2]

Historic

Jurisdiction	Company Name	Plan Term	Services Covered	Rate Escalation Provisions	Case Reference
NY	Brooklyn Union Gas	October 1, 1991 - September 30, 1994	Gas distribution	Stairstep	Case 90-G-0981, Opinion 91-21, October 9, 1991
NY	Brooklyn Union Gas	October 1, 1994 - September 30, 1997	Gas distribution	Stairstep	Case 93-G-0941, Opinion 94-22, October 18, 1994
NY	Central Hudson Gas & Electric	July 1, 2006 - June 30, 2009	Electric & Gas	Stairstep	Case 05-E-0934 & Case 05-G-0935; July 24, 2006
NY	Consolidated Edison	October 1, 1994 - September 30, 1997	Gas Distribution	Stairstep	Case 93-G-0996, Opinion 94-21, October 12, 1994
NY	Consolidated Edison	April 1, 2005 - March 31, 2008	Power distribution	Stairstep	Case 04-E-0572, March 24, 2005
NY	Long Island Lighting Company	December 1, 1993- November 30, 1996	Gas distribution	Stairstep	Case 93-G-0002, Opinion 93-23, December 23, 1993
NY	New York State Electric & Gas	December 1, 1993 - August 31, 1995	Gas	Stairstep	Case 92-G-1086, Opinion 93-22, November 9, 1993
NY	New York State Electric & Gas	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	Electric	Stairstep	Case 94-M-0349, Opinion 95-27, September 27, 1995
NY	Niagara Mohawk	July 1, 1990 - December 31, 1992	Gas	Stairstep	Case 29327, Opinion 89-37, June 28, 1991
NY	Orange & Rockland Utilities	November 1, 2003- October 31, 2006	Gas	Stairstep	Case 02-G-1553, October 23, 2003
NY	Orange & Rockland Utilities	November 1, 2006 - October 31, 2009	Gas	Stairstep	Case 05-G-1494, October 20, 2006
NY	Rochester Gas & Electric	July 1, 1993 - June 30, 1996	Gas	Stairstep	Case 92-G-0741, Opinion No. 93-19; August 24, 1993
OH	Cincinnati Gas & Electric	2009-2011	Power generation	Stairstep	Case 08-920-EL-SSO
OH	Dayton Power & Light	2009-2012	Power Distribution	Rate freeze supplemented by capex and other cost trackers	Case No. 08-1094-EL-SSO (June 2009)
VT	Green Mountain Power	2007-2010	Electric	Stairstep	Docket No. 7176
VT	Vermont Gas Systems	2007-2012	Gas	Hybrid	Docket No. 7109
Alberta	Northwestern Utilities	1999-2002	Bundled power service	Stairstep	Decision U98060 (March 31, 1998)
Alberta	EPCOR	2002-2005, Terminated 12/31/2003	Power distribution	Price Cap Index	City of Edmonton Distribution Tariff Bylaw 12367 (August 18, 2000)
BC	Fortis BC	2006-2009, extended to 2011	Bundled power service	Revenue Cap Hybrid	Order G-58-06
Ontario	All Ontario distributors	2000-2003	Power distribution	Price Cap Index	RP-1999-0034
Ontario	All Ontario Distributors	2006-2009	Power Distribution	Price Cap Index	EB-2006-0089 (December 20, 2006)
Ontario	Union Gas	2001-2003	Gas distribution	Price Cap Index	RP-1999-0017 (July 21, 2001)

[1] Rate freezes without extensive supplemental funding from capex trackers are excluded from this table.
[2] MRPs with revenue decoupling and broad-based revenue cap escalators are detailed in Table 4.

Figure 9b: Recent Canadian Multiyear Rate Cap Precedents by Province



VI. Formula Rates

A cost of service formula rate plan ("FRP") is essentially a wide-scope cost tracker designed to help a utility's revenue track its pro forma cost of service. When revenue and cost are not balanced a utility's realized ROE deviates from the target set by regulators, and earnings surpluses or deficits occur. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are substantially reduced or eliminated. Regulatory cost is reduced by limiting review of costs and revenues.

The earnings true up mechanism in an FRP calculates the revenue adjustment necessary to reduce or eliminate earnings variances. Some compare the earned ROE to the target (a/k/a benchmark) ROE and then calculate the rate adjustment needed to reduce the ROE variance. Another approach is to adjust rates for the difference between revenue and a pro forma cost of service that is calculated using a rate of return target. Both approaches often add interest on the variance to the revenue adjustment.

Earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target without sharing earnings variances. This is an important distinction between an FRP earnings true up mechanism and the earnings *sharing* mechanisms found in some multiyear rate plans. ESMs also frequently have sizable deadbands.

Expedited review of operating prudence does not always extend to major investment programs. In state-regulated FRPs for retail services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost is sometimes recovered through a separate tracker. Mechanisms are sometimes added to an FRP to encourage better operating performance in targeted areas. An example is a limit on the escalation of O&M expenses using an indexing formula.

Formula rates have been used at the FERC and its predecessor agency to regulate interstate services of gas and electric utilities since at least 1950. Use of FRPs was encouraged in the 1970s and early 1980s by rapid price inflation. Despite slower inflation in recent years, the FERC has made extensive use of formula rates for power transmission in an effort to simplify its daunting regulatory task and facilitate urgently needed investments.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are listed in Table 9 and Figure 10[7]. It can be seen that FRPs for retail utility services are operative today in several Southeast and South Central states. Alabama was an early innovator, approving "Rate Stabilization and Equalization" plans for Alabama Power and Alabama Gas in the early 1980s.[8] Formula rates are, additionally, now used to regulate electric utilities in Mississippi, some gas and electric utilities in Louisiana, and some gas utilities in Oklahoma, Texas, and South Carolina. Utilities in other states have cost trackers that act like formula rates to recover their transmission costs from retail customers Most of the recent approvals of formula rates have been for gas distribution, as this is one means of avoiding the frequent rate cases that declining average use can trigger. However, formula rates were recently authorized for electric utilities in Illinois and two are now operating under FRPs there.

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7 Some plans labeled as formula rates do not qualify for inclusion in this table and figure based on our definition.
8 For further discussion of the Alabama FRP experience see Edison Electric Institute, *Case Study of Alabama Rate Stabilization and Equalization Mechanism*, June 2011.

Table 9
Retail Formula Rate Plan Precedents[1]

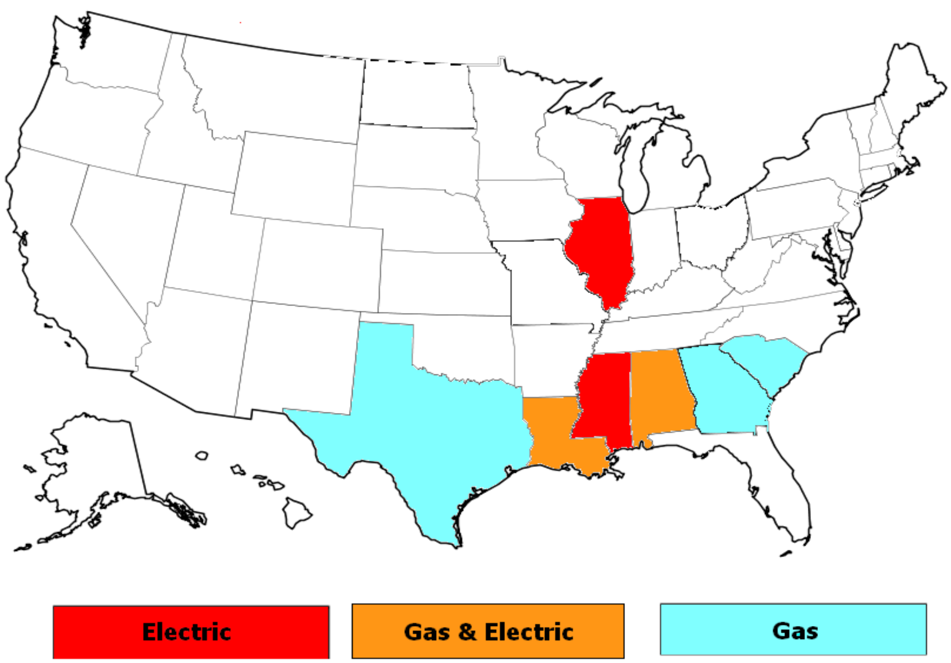
Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Current					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2006-open	Dockets No. 18117 and 18416 (October 2005)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2008-2014	Dockets No. 18406 and 18328 (December 2007)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2009-2013	Docket 28101 (December 2009)
GA	Atmos Energy	Gas	Georgia Rate Adjustment Mechanism (GRAM)	2012-open	Docket 34764 (December 2011)
IL	Ameren Illinois	Power Distribution	Rate Modernization Action Plan - Pricing (Rate MAP-P)	2011-2017	Case 12-0001 (September 2012)
IL	Commonwealth Edison	Power Distribution	Rate Delivery Service Pricing and Performance (Rate DSPP)	2011-2017	Case 11-0721 (May 2012)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2006-open	Docket No. U-21484 (May 2006)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Plan	2006-open	Docket No. U-28814 and U-28588 and U-28587(May 2006)
LA	Entergy New Orleans	Electric and Gas	Formula Rate Plan	2010-2012	Docket No. UD-08-03 (April 2009)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2009-present	Docket No. 05-UN-0503 (December 2009)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	2008-open	Docket No. 07-UN-548 (December 2007)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 5 (FRP 5)	2010-open	Docket No. 2009-UN-388 (March 2010)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 5 (PEP-5)	2010-open	Docket No. 2003-UN-0898 (November 2009)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2010-open	Docket No. 201000030 (July 2010)
OK	Oklahoma Natural Gas	Gas	Performance Based Rate of Change Plan	2010-2013	Docket No. 200800348 (April 2009)
SC	Piedmont Gas	Gas	NA	2005-present	Docket No. 2005-125-G (September 2005)
SC	South Carolina Electric and Gas	Gas	NA	2005-present	Docket No. 2005-113-G (October 2005)
TX	Centerpoint Energy-Texas Coast Division	Gas	Cost of Service Adjustment Clause	2008-open	Gas Utility Docket 9791 (October 2008)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2008 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2008
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2009 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - North Service Area	Gas	Cost of Service Adjustment Tariff	2009-open	Various Resolutions/Ordinances in service territory and Gas Utility Docket 9839 (April 2009)
Historic					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2006	Dockets No. 18117 and 18416 (March 2002)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1998-2002	Dockets No. 18117 and 18416 (March 1998)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1990-1998	Dockets No. 18117 and 18416 (March 1990)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1990	Dockets No. 18117 and 18416 (June 1985)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1982-1985	Dockets No. 18117 and 18416 (November 1982)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2007	Dockets No. 18046 and 18328 (June 2002)

Table 9 (continued)
Retail Formula Rate Plan Precedents[1]

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1996-2001	Dockets No. 18046 and 18328 (October 1996)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1991-1995	Dockets No. 18046 and 18328 (December 1990)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1987-1990	Dockets No. 18046 and 18328 (September 1987)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1987	Dockets No. 18046 and 18328 (May 1985)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1983-1985	Dockets No. 18046 and 18328 (January 1983)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2005-2009	Docket 28101 (June 2005)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2001-2005	Docket 28101 (June 2002)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2001-2003	Docket No. U-21484 (January 2001)
LA	Entergy New Orleans	Electric only	Formula Rate Plan	2004-2006	Docket No. UD-01-04 (May 2003)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2006-2009	Docket No. 05-UN-0503 (October 2005)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	1992-2006	Docket 92-UA-0230 (September 1992)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	1996-2007	Docket No. 96-UN-0202 (September 1996)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 1 (FRP 1)	1995	Docket No. 93-UA-0301 (March 1994)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4A (PEP- 4A)	2009	Docket No. 06-UN-0511 (January 2009)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4 (PEP-4)	2004-2009	Docket No. 03-UN-0898 (May 2004)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 3 (PEP-3)	2002-2004	Docket No. 01-UN-0826 (October 2002)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 2A (PEP-2A)	2001-2002	Docket No. 01-UN-0548 (December 2001)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1A (PEP-1A)	1992-1993	Docket 92-UN-0059 (July 1992)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1 (PEP-1)	1991-1992	Docket No. 90-UN-0287 (December 1990)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan	1986-1990	Docket No. U-4761 (August 1986)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2008-2010	Docket No. 200800062 (July 2008)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2004-2008	Docket No. 200400187 (November 2004)

[1] Table excludes some mechanisms that do not conform to our FRP definition. Some of these are called formula rate plans.

Figure 10: Current Retail Formula Rate Precedents by State



VII. Conclusions

Regulation of North American energy utilities is evolving to remedy the chronic underearning and frequent rate cases that traditional regulation tends to produce under modern operating conditions. Innovations continue, while some older forms of Altreg are again finding favor. This brief survey has not considered all noteworthy approaches to Altreg. Here are some of the other approaches that merit recognition:

- Regulatory assets can provide delayed compensation with interest for the annual cost of newly used and useful plant that doesn't automatically produce revenue.
- Attrition adjustments to rates can provide some compensation for an ongoing tendency of cost growth to exceed billing determinant growth. See, for example, a recent decision of the Washington Utilities and Transportation Commission in a rate case for Avista[9].
- Utilities can be permitted to file rate cases on a limited set of issues, such as additions to generation plant, that are salient causes of potential attrition.

The variety of Altreg approaches that have been established reflects the varied circumstances of individual utilities. Some are vertically integrated, while others are more specialized wire companies. Investment needs and trends in average use vary greatly. No single Altreg approach is right for every situation. The availability of multiple remedies for the underlying problems increases the chance that an approach has already been tried that fits the regulatory inclinations of a particular jurisdiction. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to make smart investments, reduce long run costs, and improve service quality without rate shock or unnecessarily frequent rate cases. Utilities can be encouraged to promote energy efficiency and peak load management aggressively. Regulators and stakeholders to regulation across the US should give priority attention to these options and consider which Altreg combinations work best in their situation.

[9] Washington Utilities and Transportation Commission, Dockets UE-120436/UG-120437, Order 09, December 26, 2012.

FORWARD TEST YEARS FOR US ELECTRIC UTILITIES

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EXECUTIVE SUMMARY

U.S. investor-owned electric utilities (electric "IOUs") in jurisdictions with historical test year rate cases are grappling today with financial stresses that threaten their ability to serve the public well. Unit costs are rising because growth in sales volumes and other billing determinants is not keeping pace with growth in cost. Cost growth is stimulated by the need to rebuild and expand legacy infrastructure and to meet environmental and other public policy goals. In this situation historical test years, still used in almost 20 U.S. jurisdictions, can erode credit quality and condemn IOUs to chronic underearning.

This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future.

CHAPTER 1 (FORWARD TEST YEARS) provides an introduction to test year issues. Problems with historical test years are discussed. We explain that the "matching principle" used to rationalize historical test years assumes that cost and revenue remain balanced. This assumption doesn't hold when unit cost is rising. In a rising unit cost environment, rates based on historical test years are uncompensatory even in the year they are implemented. As a result, operating risk increases, raising the cost of obtaining funds in capital markets. Service quality may be compromised. Customers receive out of date price signals that encourage excessive consumption. The problems are aggravated when rate hearings are protracted. Utilities commonly respond with more frequent rate case filings but these raise regulatory cost, weaken performance incentives, and distract managers from their basic business while still not giving utilities sufficient attrition relief. It is unfair to expect utilities to offset revenue shortfalls produced by regulatory lag with higher productivity and unrealistic to think that they can do so. Forward test years can yield better results for utilities and their customers.

The unit cost trends of utilities are driven by conditions that are substantially beyond their control. These conditions include trends in input prices, productivity, and the average use of utility services by customers. For the matching principle to work, some combination of growth in utility productivity and average use must offset input price inflation.

Utility efforts to promote customer energy conservation slow growth in average use, thereby raising unit cost and making historical test year rates less compensatory. Forward test years can anticipate the slower growth in average use that results from utility conservation programs. They therefore help to remove utility disincentives to promote conservation aggressively.

The forecasts of costs and billing determinants that are made in a forward test year proceeding are uncertain but involve conditions that are at most two years into the future. A large part of utility cost is no more difficult to budget under forward test years than under historical test years. More volatile components of cost are often subject to true-up mechanisms. Conservative, well-reasoned methods for making forecasts are available. In a rising unit cost environment, the uncertainty of forecasts is less of a concern than the bias of historical test year rates.

Utilities seeking forward test years must be mindful of their high evidentiary burden. The following rate case measures bolster confidence.

- Provide concrete evidence as to why future test years and not historical test years are needed under current circumstances. Evidence concerning trends in the unit cost of utilities and in key unit cost drivers is especially pertinent.
- Provide cost and billing determinant data for one or more historical reference years and carefully explain methodologies for predicting cost and billing determinant changes between those years and the forward test year.
- Use forecasting methods that are transparent and based on reason but not needlessly complex.
- Routine variance reports comparing costs and billing determinants to utility forecasts can increase comfort that forecasts are unbiased.

CHAPTER 2 (TEST YEAR HISTORY) presents a brief history of test years in the United States. Historical test years became the norm in the U.S. because periods of stable or declining unit cost, made possible by slow price inflation and brisk growth in utility productivity and average use, were the rule rather than the exception in the electric utility industry prior to the late 1960s. Growth in productivity and average use have slowed enough in subsequent decades that unit cost has frequently risen. Under favorable business conditions, unit cost can still be flat for several years, making historical test years more reasonable. However, conditions like these can give way to conditions in which unit cost rises for years at a time.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s as unit cost grew briskly, spurred by input price inflation and slower growth in average use and utility productivity. Unit cost growth was flat during most of the 1990s because business conditions driving unit cost growth were more favorable. Input price inflation slowed. Investment needs were more limited, as many utilities grew into capacity added during the construction cycle of the 1970's and early 1980's. Average use grew less rapidly than in the past but nonetheless increased appreciably in most years. Under these conditions, utilities were sometimes able to commit to multiyear base rate freezes.

Unit cost growth has since rebounded due to higher inflation, increased plant additions, and slowing growth in average use. Commissions in several states with historical test year traditions have recently moved in the direction of forward test years. Many of these states are in the West, where comparatively rapid economic growth has stimulated plant additions. The ranks of U.S. jurisdictions that use alternatives to historical test years have swollen and now encompass well over half of the total.

In summary, historical test years became the norm in U.S. rate cases during decades when unit cost was flat or declining due to remarkably brisk utility productivity and average use. Under contemporary conditions, in which average use grows slowly, if at all, and the productivity growth of utilities is more like that of the economy, unit cost may rise for extended periods undermining the matching principle.

CHAPTER 3 (EMPIRICAL SUPPORT FOR FORWARD TEST YEARS) presents results of some empirical research on test year issues. In original work for this paper, we calculated the unit cost trends of a sample of vertically integrated electric utilities from 1996 to 2008. Trends in business conditions that drive unit cost growth were measured. We also considered how test year policies affect credit metrics and utility operating performance.

Here are some salient results.

- The unit cost of sampled utilities was fairly stable from 1996 to 2002 but has since rebounded, averaging 2.3% annual growth from 2003 to 2008. The underlying causes of rising unit cost included higher input price inflation and capital spending and slower growth in the average system use of residential and commercial customers.
- In the three year period from 2006 to 2008 average use actually declined for the typical utility, pulled down by sluggish economic growth and government policies that encourage conservation. The decline was especially marked in states with large conservation programs.
- These results suggest that many IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs.
- Utilities operating under forward test years were more profitable and had better credit ratings on average than those of utilities operating under historical test years. For example, from 2006 to 2008 utilities operating under forward test years realized an average return on capital of 9.2% and maintained a typical credit rating between A- and BBB+ whereas the utilities operating under historical test years realized an average return of 7.9% and maintained a typical credit rating between BBB and BBB-.
- Examination of recent trends in operation and maintenance ("O&M") expenses of utilities provides no evidence that historical test years encourage better cost management.

CHAPTER 4 (CONCLUDING REMARKS) provides some suggestions as to how interested regulators can get started down the road to forward test years.

1. Allow a forward test year on a trial basis for one interested utility.

2. Allow forward test years on an as needed basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable.
3. Borrow one or two of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, historical test year O&M expenses can be adjusted for forecasts of price inflation prepared by respected independent agencies. Special adjustments can be made for large plant additions that are expected to be finished in the near future.
4. Try a current test year (essentially the year of the rate case), which involves forecasts only one year into the future. Current test years can be combined with interim rate increases which are subject to true up when the rate case is finalized. A combination of a current test year and interim rates eliminates regulatory lag without the necessity of a two year forecast.

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems caused by rising unit costs, alternative measures are available to relieve the financial attrition. Options include the following:

1. Make sure that historical test year calculations incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Grant utilities interim rate increases at the outset of a rate case. Even when later adjusted for the final rate case outcome, interim rates effectively reduce regulatory lag by a year.
3. Capital spending trackers can ensure timely recovery of the costs of plant additions, without rate cases, as assets become used and useful.
4. Several methods have been established to compensate utilities for acceleration in unit cost growth that results from flat or declining average system use. These include decoupling true up plans, lost revenue adjustment mechanisms, and higher customer charges.
5. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth.

1. FORWARD TEST YEARS

This chapter provides an in depth discussion of test year issues. Basic test year concepts are introduced in Section 1.1. The rationale for forward test years is discussed in Section 1.2. The kinds of evidence used in forward test year proceedings are explored in Section 1.3.

1.1 Basic Concepts

1.1.1 Rate Cases

In the United States, rates for the services of energy utilities are periodically reset by regulators in litigated proceedings called rate cases. These cases typically take about nine or ten months to resolve and sometimes end in a settlement between contending parties which is approved by the regulator. The first year following approval of new rates is called the "rate year".

In a rate case, rates are reset to reflect the cost and service levels of the utility in a test year. The first step in this process is to establish a revenue "requirement" that is commensurate with a cost for service deemed reasonable for test year operating conditions. Rates are then established which recover the revenue requirement given the levels of service provided in the test year. The service levels (*e.g.* the number of customers served and the power delivery volume) are sometimes called "billing determinants".

Bills of energy utilities often contain charges to recover the cost of energy commodities (*e.g.* fuel and purchased power) procured on a customer's behalf which are separate from the charges to recover the cost of capital, labor, and other inputs used to operate their systems. The rates that recover the costs of non-energy inputs are commonly called "base" rates. Base rate revenues are sometimes called "margins".

Rates for the cost of energy procurement are commonly subject to true ups to recover the actual cost of energy procured. Base rates, on the other hand, have traditionally been reset only in rate cases. The earnings of utilities thus depend primarily on the difference between their base rate revenues and the cost of their base rate inputs.

1.1.2 Historical Test Years

Various kinds of test years are used in rate cases today. An historical test year ("HTY") is a twelve month period that ends before the rate case filing. It typically ends a few months before the filing because it is desirable for the test year to be as current as possible but it takes several months to properly account for a year of costs and take the other steps needed to prepare a rate case. The year between an historical test year and the rate year is sometimes called the "bridge year".

The passage of time between a test year and the rate year is sometimes called "regulatory lag".[1] The lag between an historical test year and the rate year is typically two years. A utility filing for new rates in calendar 2011, for example, would typically file in March or April of 2010 using a calendar 2009 test year. Thus, historical test year rates applicable in 2011 would typically reflect business conditions in 2009.

Regulatory lag in this case has several causes. One is the necessity of using a year of historical data in the rate case filing. Another is the time required to prepare a rate case filing. Still another is the time required to execute the rate case and reach a final decision on new rates.

Historical test year data are usually adjusted in some fashion to make rates more relevant to rate year business conditions. Costs and billing determinants are often normalized for the effects of volatile business conditions on the grounds that there is no reason to expect these conditions to be abnormal during the rate year. For example, if residential and commercial delivery volumes during an historical test year were elevated by unusually high summer temperatures, they may be statistically normalized to reflect average summer weather conditions. Other examples of abnormal events that can prompt normalization adjustments include ice storms, recessions, and extended generation plant outages.

Cost and output conditions in the historical test year may also be "annualized". Effects may be removed, for a full year, of conditions that occurred during part of the HTY but are not expected to continue. One example would be costs reported for the HTY that pertained to years before the test year. Another would be the volume and peak demand of a large industrial customer who has closed its local operations.

Impacts of conditions that occurred only during certain months of the test year and are expected to prevail in the near future may also be annualized. For example, the value of the rate base at the end of an historical test year is sometimes assumed to be applicable for

[1] This is one of several definitions of "regulatory lag" which are sometimes used in discussions of regulation. Another is the length of time between rate cases.

the entire year for purposes of calculating depreciation and the return on rate base. If union wage rates are raised in the last month of the HTY pursuant to the terms of a labor contract, labor expenses may be adjusted so that the higher cost per employee is effective for the entire year.

Cost and output data may, additionally, be adjusted for "known and measurable" (sometimes called "imminent certain") changes that have already occurred since the historical test year or are likely to occur in the near future. For example, if a labor contract provides for an escalation in union wages in the bridge year, HTY cost may be adjusted to reflect the wage rates provided in the contract.

The adjustments made to HTY cost and billing determinants vary across jurisdictions. While all such adjustments tend to make rates more relevant to rate year conditions, the HTY adjustment process often ignores important changes in business conditions that occur between an historical test year and a rate year. Here are some typical omissions.

- Cost is usually not adjusted to reflect future inflation in the prices of materials, services, and new equipment because the extent of such inflation isn't known with certainty.
- Costs of plant additions in the bridge year and the rate year are often omitted if their completion date and/or final cost aren't known with certainty.
- Billing determinants are usually not adjusted to reflect trends that are likely to occur after the test year because these are not known with certainty.
- Adjustments for known and measurable changes are sometimes limited arbitrarily to the bridge year.

1.1.3 Forward and Hybrid Test Years

A forward or future test year ("FTY") is a twelve month period that begins after the rate case is filed. Test year cost and billing determinants must in this case be forecasted, and forward test years are for this reason sometimes called forecasted test years. Utilities in some jurisdictions file rate cases with *multiple* forward test years. In the Canadian province of Alberta, for instance, it has recently been common for utilities to file for two forward test years in a rate case.

Most commonly, a forward test year begins about the time that the rate case is expected to end. The test year is then the same as the rate year. A utility filing on April 1

2010, for instance, might use calendar 2011 as its test year on the assumption that the rate case will take nine months to complete.

Some utilities use FTYs that begin about the time of the rate case filing. This kind of test year may be called a "current" FTY. The initial filing is in this case based entirely on forecasts but some months of actual data for the test year become available in the course of the proceeding.

Utilities in some states make rate case filings using test years that encompass some months *before* the filing and some months *afterwards*. Data for all months of the test year are then likely to become available during the course of the filing. This kind of test year has been called a "hybrid" or "partial" test year.

1.2 Rationale for Forward Test Years

1.2.1 The Financial Challenge

The Key Role of Unit Cost

We have noted that the rates that result from a rate case are designed to recover a revenue requirement that equals cost in a test year. In the case of an historical test year the new rates embody business conditions that are typically about two years older than those of the rate year. Business conditions are likely to change between an historical test year and the rate year, causing both cost and revenue to differ from the HTY level. For rates to be exactly compensatory, base rate cost and revenue must differ from their HTY levels in the same proportion.

The assumption that cost and revenue remain in balance underlies the matching principle that regulators still use to rationalize historical test years. Kamershen and Paul note in a thoughtful 1978 article on regulatory lag that "Philosophically, the strict [historical] test year assumes the past relationship among revenues, costs, and net investment will continue into the future."[2] A 2003 NARUC *Rate Case and Audit Manual* states in this regard that

> When looking at an historical test year, one of the first questions asked is whether the test year is too stale to make it a reasonable basis upon which to establish rates for a future period… In looking at the months beyond the end of the test year, have the growth rates for rate base, expenses, and revenues all remained fairly close and constant, maintaining the test year relationship

[2] David R. Kamershen and Chris W. Paul II, "Erosion and Attrition: A Public Utility's Dilemma", *Public Utilities Fortnightly*, December 1978, p. 23.

> among these three elements, or has one element changed dramatically, making the test year out of kilter with current operations? If so, can this situation be resolved through adjustments to the test year?[3]

Cost in the rate year is likely to be substantially higher than cost in an historical test year. To understand why, consider that cost growth in any business can be decomposed into inflation in the prices it pays for inputs plus the growth in its output less the growth in its productivity:

growth Cost = growth Input Prices + growth Output – growth Productivity. [1]

The productivity growth of a business is typically not rapid enough to offset the combined effects of input price inflation and output growth. A recent study reported in testimony by Pacific Economics Group ("PEG") found, for example, that a national sample of U.S. power distributors averaged 1.03% annual growth in multifactor productivity ("MFP") from 1996 to 2006 whereas input price growth averaged 2.72% and customer growth averaged 1.00%.[4] The productivity trend of sampled distributors was similar to that of the U.S. private business sector but far from sufficient to offset the combined effects on cost of input price inflation and customer growth.

As for base rate revenue during the rate year, it can exceed the HTY revenue requirement only due to growth in billing determinants because rates are fixed at levels that reflect HTY conditions. Whether or not historical test year rates are compensatory thus depends critically on whether *unit* cost is stable in the sense that growth in billing determinants has kept pace with cost growth. If cost growth exceeds growth in billing determinants, unit cost will rise and HTY rates will be uncompensatory.

An element of complexity is added when it is considered that a utility offers many services and gathers revenue for each service from multiple charges, each with its own billing determinant. A bill for residential service, for instance, typically involves a flat monthly charge called a "customer" or "basic" charge and a "volumetric" (per kWh) charge. In this world of multiple billing determinants, historical test years will yield uncompensatory rates to the extent that cost growth between the test year and the rate year exceeds a *weighted average* of the growth in billing determinants, where the weight for each determinant is its

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[3] NARUC Staff Subcommittee on Accounting and Finance, *Rate Case and Audit Manual*, Summer 2003.
[4] Mark Newton Lowry, *et al.*, *Revenue Adjustment Mechanisms for Central Vermont Public Service Corporation*, Exhibit CVPS-Rebuttal-MNL-2 in Docket No. 7336, June 2008.

share of the total base rate revenue. In other words, rates are uncompensatory when cost growth exceeds the growth in a billing determinant *index*. This is the definition of growth in a *unit cost index*.

The utility uses most of its base rate revenue to pay its workforce, vendors of materials and services (including construction services), bondholders, and tax authorities. The residual margin, called net income or earnings, is available to provide the company's shareholders with a return on their investments. The return on equity is the component of cost that is most at risk for non-recovery when base rate revenue falls short of cost. When historical test year rates are non-compensatory they can reduce a utility's rate of return on equity ("ROE") materially.

<u>Unit Cost Drivers</u>

If the unit cost growth of a utility has made new historical test year rates non-compensatory, it may fairly be asked whether utility actions could have stopped the growth and avoided the problem. Research over many years has shown that the unit cost of a utility is driven chiefly by changes in business conditions that are beyond its control. Growth in the unit cost of a utility's base rate inputs depends on inflation in the prices it pays for those inputs, growth in the productivity with which it uses the inputs, and an average use effect:

$$growth\ Unit\ Cost = growth\ Input\ Prices - (growth\ Productivity + Average\ Use). \qquad [2]$$

We discuss each of these unit cost "drivers" in turn.

Input Price Inflation Inflation routinely occurs in the prices utilities pay for labor, materials, services, and equipment. Since utilities have capital-intensive technologies, inflation in the price of capital is an especially important driver of their input price growth. The trend in the price of capital depends chiefly on trends in construction costs, tax rates, and the going rates of return on debt and equity in capital markets.[5]

Productivity The productivity growth of a utility depends on various conditions that include technological change, the realization of scale economies, and the pace of plant additions as

[5] The impact of construction cost on price inflation is complex. In setting rates, utility plant is valued in historical dollars. The cost of service thus depends on prices paid for construction in past decades. Construction costs in more recent years matter more because the corresponding assets are less depreciated. The rate base will tend, on average, to reflect construction costs more than a decade into the past. For most utilities, new investments therefore embody more than a decade of construction cost inflation compared to investments of average vintage. This is one of the reasons why unusually large plant additions can increase the rate base so substantially.

well as utility efforts to root out inefficiencies. Plant additions may boost efficiency gains in the long run but can slow them in the short run, especially if they involve major investments such as new base load generating units, advanced metering infrastructure, or an accelerated program to replace aging infrastructure. Scale economies depend on the pace of output growth and on whether the utility is so large that it has reached a minimum efficient scale at which incremental scale economies from output growth aren't available.

The ability of utilities to achieve productivity surges is limited in the short run. Since technology is capital intensive, the depreciation and return on rate base associated with older investments --- which cannot be changed in the short run --- account for a large share of the total cost of base rate inputs. A utility can increase productivity only by slowing growth in O&M expenses and plant additions. Opportunities to achieve *sustained* productivity gains often involve sizable upfront costs and net gains may not occur for more than a year. A downsizing of the labor force, for instance, may involve severance payments. The chief means for a utility to trim its cost in the very short run is to defer maintenance expenses and plant additions. Such deferrals must be followed by higher expenses in short order if service quality is to be maintained. A utility can't rely on a deferral strategy year after year when it is filing frequent rate cases.

Average Use A utility's unit cost growth also depends on the difference in the impact that its output growth has on its revenue and its cost. When output growth boosts revenue more than cost, unit cost growth slows. When output growth causes cost to rise more rapidly than revenue, unit cost growth accelerates.

A utility's output growth has different impacts on revenue and cost when two conditions are present. One is that the design of base rates doesn't reflect the drivers of base rate input cost. The other is that billing determinants tend to grow at a different rate than cost drivers.

Consider, first, whether the design of utility base rates is cost causative. The cost of a utility's base rate inputs is largely fixed in the short run with respect to system use. Cost is much more sensitive to growth in the number of customers served.[6] As for billing determinants, we have seen that utility tariffs for most services involve multiple charges. These include one or more "variable" charges that are so called because they vary with

[6] Cost growth may also depend, in the long run, on the growth in peak demand and/or the delivery volume.

system use. Volumetric charges vary with the volume of power delivered. "Demand" charges vary with the peak level of demand (*i.e.* the highest hourly volume registered during the month). There are, additionally, "fixed" charges that are so called because they do not vary with a customer's use of the system during the billing period. Chief amongst the fixed charges of electric utilities are customer charges. Residential and small business customers account for the bulk of a utility's base rate revenue because these customers account for the bulk of a utility's cost. In these customer classes, base rate revenue is drawn chiefly from volumetric charges.

Under these circumstances, the difference between the way that output growth affects revenue and cost is chiefly a matter of the difference between the trends in the volume of sales to residential and small business customers and the trends in the number of customers served. This is equivalent to the trends in the delivery *volume per customer* of these service classes, which are sometimes referred to as the trends in their average (system) use. Unit cost growth slows when average use rises and accelerates when growth in average use slows.

In the electric utility industry, as in most sectors of the economy, the productivity growth of utilities has for decades been a good bit slower than the inflation in the prices they pay for inputs.[7] The recent PEG study noted earlier, for example, found that power distributor productivity growth fell short of input price growth by about 169 basis points annually on average from 1996 to 2006.[8] Under conditions like these, the average use trends of residential and small-volume business customers play an important role in determining whether a utility's unit cost rises. If growth in average use is *brisk* (*e.g.* 1.5 to 2% annually), the difference between input price and cost efficiency growth can be offset.[9] If average use is *static*, unit cost will rise substantially even under normal inflationary conditions. If average use is *declining*, the rise in unit cost can be quite rapid.

Recent changes in state and federal policy are encouraging more electricity demand-side management ("DSM") and development of customer-sited solar resources. These policies include net metering, tighter appliance efficiency standards and building codes, and

[7] The difference is greater in periods of brisk input price inflation and smaller in periods of slow inflation, since productivity does not characteristically rise and fall with inflation.
[8] Lowry *et al.* (2008) *op. cit.*
[9] Irston Barnes wrote, for example, in a classic treatise on rate regulation, that "as an offset to such factors making for rising rates, the increased volume of business that usually accompanies an upward movement of prices may so reduce the overhead charges per unit as to make any increase in rates unnecessary". See Irston R. Barnes, *The Economics of Public Utility Regulation* (New York: F.S. Crofts, 1942).

subsidies for energy efficiency investments. Our discussion suggests that such programs can accelerate unit cost growth by slowing growth in average use. Whether or not the utility provides DSM programs, average use can become static or decline, removing a key means by which utilities have traditionally coped with input price inflation and avoided unit cost growth. The problem can be remedied by redesigning rates in ways that raise customer charges. But rate designs are regulated and regulators in the United States generally do not sanction high customer charges.[10]

Implications Our analysis suggests that the unit cost of an electric utility is likely to rise, making historical test year rates non-compensatory, to the extent that the following external business conditions prevail.

- Input price inflation is brisk.
- Utilities need to make large plant additions that temporarily slow productivity growth.
- Average use of the utility system is static or declining.

Situations in which unit cost is stable, encouraging use of historical test years, include those in which inflation is slow, utilities aren't making large plant additions, and average use is growing briskly.

A program to accelerate the replacement of aging distribution facilities provides a classic example of the non-compensatory nature of historical test year rates. Suppose that a power distributor replaces 10% of its distribution infrastructure during a year when new rates are implemented. The new plant has capacity similar to the plant replaced but reflects more than forty years of construction cost inflation. The company's rate base will rise substantially, temporarily slowing productivity growth and accelerating unit cost growth. Even with normal growth in input prices and average use a utility with rates based on historical test years may earn little return on this sizable investment for as much as two years after it becomes used and useful.

Conclusions

These results permit us to draw several conclusions concerning the reasonableness of historical test years in ratemaking.

[10] High customer charges are more common for U.S. gas utilities and for gas and electric IOUs in Canada.

1) Historical test years are rationalized by a matching principle that assumes a balance of cost and revenue. Our analysis shows that this relationship is not balanced in a rising unit cost environment.
2) An individual utility reporting that rates produced by historical test years are uncompensatory may be suspected by stakeholders of poor cost management. However, research shows that a utility's unit cost trend is determined primarily by business conditions over which it has little control. These include the trends in input price inflation, average use, and the need for plant additions.
3) In a rising unit cost environment, the ability of a utility to "take a hair cut" between the historical test year and the rate year is limited. Long term performance gains involve upfront costs. Deferment of expenses lowers cost today at the expense of higher costs in the future.
4) Absent favorable operating conditions, the rise in a utility's unit cost due to changing business conditions may be so great that it is unable to earn its allowed rate of return under historical test year rates even with normal productivity gains. As Kamerschen and Paul comment, "while a utility is never guaranteed that it will earn its authorized fair rate of return, if no allowance is made for attrition or the other explosive elements, the utility is denied a realistic opportunity of earning the permitted rate of return."[11] In this situation, rates produced by historical test years are inherently unjust and unreasonable. This can prompt the investment community to downgrade its credit valuations, not just for the subject utility but for other utilities in the same jurisdiction.
5) Firms in competitive markets have ways of coping with rising unit costs that aren't available to utilities. The prices a competitive firm receives for its products will tend to rise at the same pace as the unit cost of its industry. Firms experiencing unit cost growth in excess of growth in sales prices can always scale back their offerings. A utility, in contrast, charges prices set by regulators which may not be reflective of unit cost trends. The utility is obligated to provide service even if prices are non-compensatory due to flawed ratemaking practices.

[11] Kamerschen and Paul *op. cit.* p. 23.

6) Unit cost pressures are not constant over time. Several years of flat unit cost can give way to a sustained period of rising unit cost. Thus, historical test years can produce reasonable results for many years and then become uncompensatory for many years due to rising unit cost. A utility's success at earning its allowed ROE during a string of recent years does not necessarily mean that a forward test year isn't warranted prospectively.
7) Forward test years have major advantages over historical test years in a rising unit cost environment. Rates are more likely to reflect unit cost conditions in the rate year and are, to this extent, more just and reasonable. Customers receive better price signals. Lower operating risk reduces the utility's cost of securing funds in capital markets. This benefit is especially important in periods of large plant additions, when high borrowing costs can have an especially large impact on the embedded cost of debt.
8) Whether or not unit cost is rising, historical test years do not adjust rates for slowdowns in volume growth, between the test year and the rate year, which are due to utility conservation initiatives. They therefore dampen utility incentives to encourage conservation.

1.2.2 Uncertainty

Opponents of forward test years often stress the uncertainty of cost and billing determinant forecasts. Future costs cannot be verified. The changes in business conditions that drive unit cost growth (*e.g.* inflation and the in service dates on looming plant additions) can be hard to predict accurately. The impact that changing business conditions have on unit cost is not always well understood. Opponents also argue that utilities are incented to exaggerate future cost growth and to understate future growth in billing determinants. Cost and billing determinants in a historical test year are, meanwhile, known with certainty.

On the other hand, the projections at issue in a forward test year concern business conditions that are at most two years into the future. A large chunk of future cost, the depreciation and the return on older plant, is known with considerable certainty at the time that the forecast is made. There are many aids in the preparation of credible forecasts, as we discuss further in Section 1.3. Consider also that volatile components of a utility's unit cost (*e.g.* expenses for pensions and uncollectible bills) are often subject to trackers that reduce or eliminate the risk of bad forecasts.

Current test years involve less forecasting uncertainty because the test year is only a year into the future at the time that the rate case is filed. Actual data for some or all months of the test year become available in the course of the proceeding. The accuracy of the methods used to forecast cost and billing determinants can thus be tested against their ability to predict the actuals in some months of the test year.

FTY projections are, in any event, quickly followed by actual data, and a utility that makes forecasts that are consistently biased in its favor will find that its forecasts are discounted in ratemaking. Biased forecasts can even jeopardize a regulator's willingness to use forward test years. The other stakeholders to the rate case process have incentives to bias cost and sales forecasts in the other direction. These circumstances reduce or eliminate the bias of the forecasts on which FTY rates are ultimately based. If the forecast of future cost and output is accurate, the utility will receive revenue that is exactly equal to its cost. FTY rates will be fair to the utility and ratepayer alike, whereas historical test year rates are likely to be biased in a rising (or falling) unit cost environment.

On balance then forward test year rates, while involving some uncertainty, are likely to be more reflective of future business conditions than are historical test year rates in a rising unit cost environment. The uncertainty involved in basing rates on FTYs is no greater than that involved in rate freezes and other kinds of multiyear rate plans that are often approved by regulators. The Michigan Public Service Commission ("PSC") commented, in a recent decision on an FTY rate filing for Consumers Energy, that

> The basis for using a forward test year is to address the problem of regulatory lag between past and future costs. While the advantage of historical data is its objective and verifiable nature, it lacks the necessary forward perspective required in a changing economic environment. An historical test year is by definition not timely and may fail to adequately consider future demands….What is gained by dealing with data that is "known and measurable" can be lost in forcing a utility to operate with outdated numbers.[12]

[12] Michigan PSC *Opinion and Order*, Case U-175645, November 2009.

1.2.3 Regulatory Cost

A third consideration in weighing the advantages of historical and forward test years is regulatory cost. The net impact of forward test years on regulatory cost is difficult to assess. Forward test year rate cases typically do involve higher cost than rate cases based on historical test years because of the need for forecasts.

On the other hand, a number of the major issues in a rate case, including the depreciation rates and the rate of return on common equity, are not markedly more complicated in a forward test year proceeding. Depreciation on existing plant is easy to predict once a depreciation rate is established. Some of the more uncertain components of cost and revenue may be subject to trackers that mitigate rate case controversy. The cost of FTY rate cases falls as jurisdictions gain experience with forecasted evidence. Consider also that in a rising unit cost environment rates based on forward test years can, by reducing earnings attrition, sometimes reduce the frequency of rate cases.

1.2.4 Operating Efficiency

The effect of alternative test year approaches on utility operating efficiency is also frequently discussed in debates on test year approaches. Opponents of forward test years sometimes argue that they weaken utility incentives to operate efficiently. In a rising unit cost environment, an expectation that rates are going to be non-compensatory might encourage utilities to tighten their belts. FTY opponents also argue that a utility wishing to inflate its cost in an historical test year, in an effort to create higher rates in the rate year, would incur a real cost to do so.

On the other hand, the notion that rate cases generally weaken utility performance incentives is a central result of regulatory economics and is not confined to future test years. When a utility is operating under a series of annual rate cases with historical test years, cost savings this year lead quickly to lower rates. The fact that a forward test year involves forecasts does not in and of itself weaken performance incentives. Forward test year forecasts are often linked to actual costs in one or more historical reference years, so the utility must once again incur a real cost if it wishes to bolster its argument for higher costs in the test year.

Consider also that when unit cost is rising, the non-compensatory rates yielded by forward test years may cause utilities to file rate cases more frequently. This weakens performance incentives, and senior managers devote less time to the utility's basic business of providing quality service at a reasonable cost. Analysis by PEG Research has revealed that reducing the frequency of rate cases from one to three years increases a utility's productivity performance by about 50 basis points annually in the long run.[13] We therefore do not expect utility operating incentives to differ significantly between historical and forward test years on balance.

It is, in any event, unreasonable for stakeholders and regulators to acquiesce in non-compensatory HTY rates on the grounds that they encourage utilities to trim "fat" if the existence of fat has not been demonstrated in the rate case. J. Michael Harrison, an administrative law judge with the New York PSC, commented in this regard in a 1979 article on forward test years that

> It is reasonable to set rates conservatively when company's management or operations are significantly and demonstrably poor… Evidence of general management inadequacy, however, is rarely seen in rate cases and … management normally will be striving to improve efficiency in periods of continuously rising costs. Regulatory commissions certainly have an obligation to monitor operations and management effectiveness, but it does not appear justifiable to indulge in a presumption, absent specific evidence to the contrary, that deficient earnings can be attributed to management shortcomings rather than to unfavorable operating conditions.[14]

1.2.5 Other Considerations

Here are some additional considerations that merit note in a discussion of forward test year pros and cons.

- Forward test years encourage the utility, other stakeholders, and the Commission to focus more attention on the utility's plans for the future. Undesirable trends, such as rising costs that reflect inadequate attention to productivity growth, can be recognized and discouraged in advance of their occurrence. Budgeting is apt to play a more central role in cost management.

[13] See, for example, "Incentive Plan Design for Ontario's Gas Utilities", a presentation made by the senior author in work for the Ontario Energy Board in November 2006.
[14] J. Michael Harrison, "Forecasting Revenue Requirements", *Public Utilities Fortnightly*, March 1979, p. 13.

- Forward test year rate cases sharpen the ability of the regulatory community to undertake and review statistical analyses of unit cost trends. These same skills are useful in the design of multiyear rate plans in which rates are adjusted automatically between rate cases to reflect changing business conditions. Multiyear rate plans can reduce regulatory cost and strengthen utility performance incentives, creating benefits that can be shared with customers.

1.3 Evidentiary Basis for FTY Forecasts

Good evidence on future costs and billing determinants is critical to the effectiveness of forward test year rate cases. The New York PSC stated, in an order rejecting a forward test year for New York State Electric and Gas in 1972, that

> To justify the commission in deviating from its long-standing policy of using an actual test year adjusted for known changes, there must be a full showing that such a change is a practical necessity. This showing must encompass the twin requirements of substantial accuracy and an impending, uncontrollable diminution in profitability.

We have already discussed at some length the kinds of conditions that can cause unit cost to rise between an historical test year and the rate year. We consider here kinds of evidence used in FTY rate cases that increase the confidence of regulators that forecasts are accurate.

Linkage to Historical Data

Utilities in forward test year rate cases usually file detailed and extensive evidence concerning cost and billing determinants in one or more historical reference years.[15] Data for these years are usually subject to normalization and annualization adjustments like those used in historical test year filings. The utility will then present evidence on expected changes in cost and billing determinants between the historical reference year and the test year.[16] Cost projections are often made for the same detailed Uniform System of Account categories that are used in historical test year rate cases. J. Michael Harrison commented in this regard in his 1979 article that "the New York commission's requirement that a verifiable nexus be established between a forecast and an historical base of actual experience is a sine qua non

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[15] An historical reference year is sometimes called a "base period".
[16] This sometimes includes a forecast of cost during the rate case year (if different), which is sometimes called the "bridge year".

for forecasting revenue requirements. The burden of proving the reasonableness of its filing remains with the utility company."[17]

Indexation

Indexation is used by several utilities in FTY rate cases to escalate cost items for changing business conditions. Recall from Section 1.2.1 that the growth in the cost of a utility equals the inflation in the prices it pays for inputs plus the growth in its output less the trend in its productivity. The trend in the productivity of utilities tends to be similar to the growth in their output. Testimony just prepared by PEG Research for San Diego Gas & Electric reports that, for a national sample of power distributors, MFP averaged 0.88% annual growth from 1999 to 2008 while the number of customers served averaged 1.37% average annual growth.[18] An assumption that productivity growth equals output growth makes it possible to escalate cost from historical reference year(s) values by the forecasted growth in prices. This is the most common use of indexing in FTY forecasts.

The United States is fortunate to have available some of the best data in the world on utility input price trends. One company, Whitman, Requardt and Associates, has for decades published "Handy Whitman Indexes" of trends in the construction costs of both gas and electric utilities.[19] These are available for six geographic regions of the United States for detailed asset classes. Another company, Global Insight, has a *Power Planner* service that has forecasts, updated quarterly, of construction cost indexes. Global Insight also forecasts inflation in the prices of labor, materials, and services used by gas and electric utilities.[20] The materials and service ("M&S") price indexes are available for the detailed O&M expense categories that are itemized in the FERC's Uniform System of Accounts. Global Insight input price indexes have been used for many years to adjust revenue requirements in the multiyear rate plans of California gas and electric utilities.

Some utilities instead escalate O&M expenses in rate cases using familiar macroeconomic price indexes. The gross domestic product price index ("GDPPI") is often preferred for this purpose to the better known consumer price index because the GDPPI assigns less weight to price volatile commodities, such as food and energy, which do not

[17] J. Michael Harrison, *op. cit.*, p. 13.
[18] Mark Newton Lowry *et al.*, *Productivity Research for San Diego Gas & Electric*, August 2010.
[19] Whitman, Requardt & Associates LLP, "The Handy-Whitman Index of Public Utility Construction Costs".
[20] A discussion of an early use of detailed inflation forecasts in ratemaking is found in Michael J. Riley and H. Kendall Hobbs, Jr. "The Connecticut Solution to Attrition", *Public Utilities Fortnightly*, November 1982.

loom large in base rate input costs. Our research over the years has found that the GDPPI and CPI both tend to understate escalation in the prices of utility O&M inputs. One reason is that they are measures of inflation in the economy's prices of final goods and services and therefore reflect the productivity growth of the U.S. economy, which has been substantial in recent years. In a recent report for Hawaiian Electric, for instance, PEG found that from 1996 to 2007 the GDPPI averaged 2.21% average annual growth whereas an index of the O&M input prices paid by HECO averaged 3.05% average growth.[21] The GDPPI should therefore inspire confidence as an O&M escalator that often yields reasonable results for customers.

Simple Trend Analyses

Simple approaches to forecasting based on historical trends can, if well designed, strike a reasonable balance between the desire of regulators for accuracy and simplicity. For example, a given cost item can equal its adjusted value in the historical reference year, plus a one or two-year escalation for the average annual growth of this cost for a group of peer utilities in recent years. This approach is more sensible to the extent that the recent inflation, productivity, and output trends of the peers are similar to those that the subject utility will experience in the near future. A refinement on this general approach would be to assume a trend in cost *per customer* equal to the recent historical trend of peer utilities and then to reach cost by adding a forecast of the utility's own customer growth. Simple methods like these have counterparts for the forecasting of billing determinants. For example, the volume of residential sales in a future test year can be forecasted as the expected number of customers multiplied by the expected volume per customer, where the latter is allowed to differ from the normalized value(s) in the historical reference year(s) by its normalized trend in the last three years.

Budgeting

Some utilities use the same figures in forward test year filings that they use in their own budgeting process.

[21] Mark Newton Lowry *et al.*, *Revenue Decoupling for Hawaiian Electric Companies*, Pacific Economics Group, January 2009. pp. 65-66.

<u>Econometric Modeling</u>

Econometric modeling is used by several utilities in FTY cost and billing determinant projections. In an econometric model, the variable to be forecasted is posited to be a function of one or more external business conditions. Model parameters are estimated using historical data on the variable to be forecasted and the business conditions. A rich theoretical and empirical literature is available to guide model development. Given forecasts of the business conditions, the model can forecast how cost will grow between one or more historical reference years and the forward test year.

<u>Benchmarking</u>

Utilities can bolster the confidence of regulators in their FTY cost forecasts by benchmarking them using data from other utilities. A variety of benchmarking methods are available, ranging from econometric modeling to peer group comparisons that use simple unit cost metrics. Public Service of Colorado, for instance, recently filed a study in an FTY rate case filing that benchmarked their non-fuel O&M expense forecast.[22] The study used an econometric benchmarking model as well as unit cost metrics for a Western Interconnect peer group. The authors found that the forecasted expenses reflected a high level of operating efficiency.

[22] See Public Service Company of Colorado's Exhibit MNL-1 in docket 09AL-299E before the Public Utilities Commission of Colorado, filed October 13, 2009.

2. TEST YEAR HISTORY AND PRECEDENTS

2.1 A Brief History

Few states have laws on the books that mandate a particular test year approach. Statutes instead commonly feature more general provisions on regulation such as guidelines that rates be just and reasonable, that terms of service be non-discriminatory, and that service be of good quality. Flexibility with respect to test years is also encouraged by the Supreme Court's influential *Hope* decision, which held that

> The Commission was not bound to the use of any single formula or combination of formulae in determining rates. Under the statutory [Natural Gas Act] standard of "just and reasonable" it is the result reached and not the method which is controlling…If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end.[23]

Historical test years were nonetheless the norm in the early history of electric utility rate cases, and this reflects the prevalence over many years of business conditions that were conducive to slow unit cost growth. Slow price inflation was a contributing factor. Table 1 shows the history of GDPPI inflation in the United States from 1930 to 2009. It can be seen that inflation was negative in most years of the 1930s but was brisk during World War II, the immediate post war years, and in 1951. After the Korean War, the table shows that GDPPI inflation averaged only 1.74% annually in the 1952-1965 period.

Table 1 also shows the trend in the MFP index for the electric, gas, and sanitary sector of the U.S. economy. This index was computed by the U.S. Bureau of Labor Statistics ("BLS") for many years and was sensitive to the productivity trend in the electric utility industry due to the industry's disproportionately large size. It can be seen that the productivity growth of the electric, gas, and sanitary sector was extraordinarily rapid during the 1952-65 period, averaging 4.13% per annum. This was more than double the MFP index trend for the U.S. non-farm private business sector as a whole.

Under these favorable operating conditions, the unit cost of the electric utilities was typically stable or declining.[24] Rate cases were rare and historical test years were the norm in the rate cases that did occur. Regulators gained confidence that the matching principle could

[23] 320 U.S. 591.
[24] See Paul Joskow, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation", *Journal of Law and Economics*, 1974 for an insightful discussion of some of this history.

Table 1

U.S. Inflation and Productivity Trends

		GDP Price Index		Multifactor Productivity: Private Non-Farm Business		Multifactor Productivity: Electric, Gas & Sanitary Sector	
	Year	Index	Growth	Index	Growth	Index	Growth
	1929	10.6		NA	NA	NA	NA
	1930	10.2	-3.94%	NA	NA	NA	NA
	1931	9.2	-10.45%	NA	NA	NA	NA
	1932	8.1	-12.08%	NA	NA	NA	NA
	1933	7.9	-2.66%	NA	NA	NA	NA
	1934	8.3	4.78%	NA	NA	NA	NA
	1935	8.5	1.97%	NA	NA	NA	NA
	1936	8.6	1.09%	NA	NA	NA	NA
	1937	8.9	3.61%	NA	NA	NA	NA
	1938	8.7	-1.90%	NA	NA	NA	NA
	1939	8.6	-1.27%	NA	NA	NA	NA
	1940	8.7	0.87%	NA	NA	NA	NA
	1941	9.2	6.32%	NA	NA	NA	NA
	1942	10.0	7.91%	NA	NA	NA	NA
	1943	10.6	5.47%	NA	NA	NA	NA
	1944	10.8	2.37%	NA	NA	NA	NA
	1945	11.1	2.52%	NA	NA	NA	NA
	1946	12.4	10.90%	NA	NA	NA	NA
	1947	13.7	10.54%	NA	NA	NA	NA
	1948	14.5	5.52%	53.0	NA	37.1	NA
	1949	14.5	-0.06%	53.8	1.41%	37.7	1.66%
	1950	14.6	0.78%	57.2	6.08%	40.5	7.20%
	1951	15.6	6.66%	58.6	2.47%	44.4	9.16%
	1952	16.0	2.15%	59.0	0.67%	46.3	4.19%
	1953	16.2	1.26%	59.9	1.59%	48.1	3.80%
	1954	16.3	1.01%	59.9	-0.12%	50.0	4.01%
	1955	16.6	1.42%	62.4	4.15%	53.9	7.41%
	1956	17.1	3.39%	61.6	-1.33%	56.6	4.99%
	1957	17.7	3.44%	62.3	1.11%	58.7	3.59%
	1958	18.1	2.28%	62.4	0.29%	60.3	2.71%
	1959	18.3	1.13%	65.2	4.35%	64.1	6.10%
	1960	18.6	1.39%	65.5	0.51%	66.0	2.95%
	1961	18.8	1.12%	66.6	1.54%	67.7	2.41%
	1962	19.1	1.36%	68.9	3.46%	70.9	4.68%
	1963	19.3	1.05%	70.8	2.68%	72.3	2.02%
	1964	19.6	1.54%	73.5	3.72%	76.1	5.02%
	1965	19.9	1.80%	75.6	2.82%	79.2	4.00%
	1966	20.5	2.80%	77.7	2.82%	82.4	4.07%
	1967	21.1	3.03%	77.8	0.06%	85.0	3.01%
	1968	22.0	4.16%	79.8	2.56%	88.8	4.42%
	1969	23.1	4.82%	79.2	-0.76%	91.2	2.69%
	1970	24.3	5.14%	78.8	-0.50%	92.7	1.56%
	1971	25.5	4.88%	81.3	3.11%	93.8	1.21%
	1972	26.6	4.22%	83.7	2.87%	95.4	1.70%
	1973	28.1	5.39%	86.1	2.87%	97.2	1.88%
	1974	30.7	8.66%	83.2	-3.35%	94.0	-3.31%
	1975	33.6	9.06%	83.6	0.43%	94.2	0.18%
	1976	35.5	5.58%	86.8	3.77%	95.4	1.28%
	1977	37.8	6.17%	88.1	1.46%	95.2	-0.25%
	1978	40.4	6.78%	89.4	1.47%	95.1	-0.04%
	1979	43.8	7.99%	88.8	-0.67%	94.0	-1.21%
	1980	47.8	8.75%	86.9	-2.20%	93.5	-0.53%
	1981	52.3	9.01%	86.5	-0.42%	93.5	0.04%
	1982	55.5	5.92%	83.5	-3.59%	92.6	-1.04%
	1983	57.7	3.87%	86.6	3.68%	91.4	-1.23%
	1984	59.8	3.69%	88.7	2.35%	94.5	3.34%
	1985	61.6	2.98%	89.2	0.65%	94.4	-0.16%
	1986	63.0	2.20%	90.6	1.47%	94.7	0.35%
	1987	64.8	2.76%	90.7	0.16%	94.8	0.04%
	1988	67.0	3.38%	91.7	1.04%	98.5	3.84%
	1989	69.5	3.71%	91.7	0.00%	98.9	0.44%
	1990	72.2	3.80%	92.0	0.40%	100.4	1.49%
	1991	74.8	3.47%	91.3	-0.80%	100.2	-0.18%
	1992	76.5	2.35%	93.5	2.39%	100.0	-0.21%
	1993	78.2	2.18%	93.7	0.18%	102.6	2.52%
	1994	79.9	2.08%	94.4	0.78%	103.2	0.67%
	1995	81.5	2.06%	94.5	0.09%	105.6	2.22%
	1996	83.1	1.88%	95.8	1.42%	106.9	1.24%
	1997	84.6	1.76%	96.5	0.66%	106.9	-0.02%
	1998	85.5	1.12%	97.7	1.28%	107.0	0.11%
	1999	86.8	1.46%	99.0	1.27%	NA	NA
	2000	88.6	2.15%	100.0	1.05%	NA	NA
	2001	90.7	2.24%	100.4	0.39%	NA	NA
	2002	92.1	1.60%	102.5	2.08%	NA	NA
	2003	94.1	2.13%	105.2	2.60%	NA	NA
	2004	96.8	2.80%	108.0	2.60%	NA	NA
	2005	100.0	3.28%	109.3	1.26%	NA	NA
	2006	103.3	3.21%	109.9	0.51%	NA	NA
	2007	106.2	2.82%	110.1	0.21%	NA	NA
	2008	108.5	2.11%	111.4	1.13%	NA	NA
	2009	109.7	1.16%	NA	NA	NA	NA
Averages	**1952-1965**		**1.74%**		**1.82%**		**4.13%**
	1973-1981		**7.49%**		**0.37%**		**-0.22%**
	1982-1991		**3.58%**		**0.54%**		**0.69%**
	1992-2003		**1.92%**		**1.18%**		**NA**
	2004-2008		**2.84%**		**1.14%**		**NA**

yield just and reasonable rates.

The unit cost growth of electric utilities accelerated in the late 1960s and remained high for about two decades thereafter for several reasons.

- Price inflation accelerated, spurred initially by the Vietnam War and subsequently by the oil price shocks of 1974-75 and 1979-80. During the 1973-81 period, GDPPI inflation averaged 7.49% annually. Inflation thereafter slowed but still averaged 3.58% annually during the 1982-91 period.
- Rising utility rates and slowing economic growth slowed growth in use per customer.
- Utility productivity growth, far from keeping pace with inflation, slowed substantially falling by 0.22% annually on average in the 1973-1981 period and averaging only 0.69% annual growth in the 1982-91 period. Factors contributing to the slowdown included the exhaustion of scale economies by some of the nation's larger electric utilities and the propensity of some utilities to continue making major plant additions despite slower demand growth.

Under these changed conditions, utilities in the two decades after 1967 sought financial relief by filing frequent rate cases. However, many utilities found that they could not earn their allowed ROE under newly established rates. One author commented in 1974, a particularly bad year, that "it would be difficult, if not impossible, to find a utility which has been able in the first year in which a rate increase was in effect to earn the return on which the rate increase was predicted".[25] A study found that the earned ROE on equity in the electric utility industry was more than 200 basis points below the allowed rate of return on average in 1974, 1979, and 1980.[26] Interest coverage fell markedly for many utilities, limiting their ability to issue new debt. Financing of new investments required greater reliance on issuance of new common stock, and the value of stock fell below the book value of assets in many cases. Articles about attrition and regulatory lag appeared with regularity in the trade press.[27]

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[25] W. Truslow Hyde, "It Could Not Happen Here – But it Did", *Public Utilities Fortnightly*, June 1974.
[26] Walter G. French, "On the Attrition of Utility Earnings", *Public Utilities Fortnightly*, February 1981.
[27] See, as another example, Theodore F. Brophy, "The Utility Problem of Regulatory Lag", *Public Utilities Fortnightly*, January 1975.

Regulators responded to this situation with an array of measures, some of which had been used at one time or another in the past. The measures included interim rate increases; the inclusion of construction work in progress ("CWIP") in rate base; more widespread use of fuel adjustment clauses; the addition of an "attrition allowance" to the target ROE, and more widespread use of forward and hybrid test years. Adopters of FTYs in these years of brisk unit cost growth included the Federal Energy Regulatory Commission ("FERC") and state commissions in California, Connecticut, Florida, Georgia, Hawaii, and New York.

Some of these states initially experimented with hybrid test years which, as we have noted, make it possible to update rate filings as actual data for the later months of the test year become available. J. Michael Harrison explained in his 1979 article some grounds for dissatisfaction with hybrid test year experiments:

> Parties charged with testing or contesting a utility's rate case presentation were faced with figures and issues that changed and shifted through all phases of the case. Even after their direct evidentiary presentations were made, these parties were faced with a required reevaluation of their positions and the possibility that a host of new issues would be created by emerging actual data. The commission staff, which in New York bore the brunt of this burden, faced an almost impossible task of analyzing new data, even as its case went to the administrative law judge or commission for decision. It became clear that the value of the already completed hearings was being seriously undermined. [28]

The New York Commission decided in 1977 to move to fully forecasted test years consisting of the first twelve months expected under the new rates.[29]

The need for forward test years subsided with the slowdown of unit cost growth that occurred in the electric utility industry in the 1990s. This slowdown was driven primarily by a partial reversal of the business conditions that had previously caused brisk unit cost growth. During the 1992-2003 period GDPPI growth averaged only 1.92% per year. Yields on newly issued long term bonds fell substantially as the market lowered its expectation of future inflation. The productivity growth of the electric, gas, and sanitary sectors increased modestly, averaging 0.94% annually during the 1992-98 period, a trend similar to that of the private business sector. One reason for the productivity rebound was a slowdown in plant additions as the industry increased utilization of the generation and transmission capacity

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[28] J. Michael Harrison, *op. cit.*, p. 12.
[29] New York Public Service Commission, "Statement of Policy on Test Periods in Major Rate Proceedings", November 1977.

built in the previous twenty years. Several electric utilities operated under base rate freezes during these years. Their willingness to agree to freezes reflected in part the generally favorable unit cost conditions but sometimes also reflected an expected spurt of productivity growth due to participation in mergers or acquisitions.

Interest in forward test years has renewed for electric utilities in recent years due to a renewed growth in unit cost, which is discussed in more detail in Section 3.1 below. We note here that general inflation accelerated after 2003, with GDPPI growth averaging 2.84% annually during the 2004-2008 period. Inflation slowed in 2009 but will likely rebound as the world economy recovers from the recession. Utility investment needs increased during the period to replace aging facilities, reverse declining generation capacity margins, implement “smart grid” technologies, and meet the rising demand for transmission services to reach remote sources of renewable energy and promote bulk power market competition. Growth in average use has slowed with slowing economic growth and new initiatives to promote energy conservation.

Interest in forward test years has been especially keen in the American west. Brisk economic growth in most western states has increased the need for plant additions. Here is a brief summary of changing test year policies in selected states.

<u>Colorado</u>

In Colorado, the commission rejected an FTY request by Public Service of Colorado in 1993 but acknowledged that “the purpose of a test year is to provide, as closely as possible, an interrelated picture of revenue, expense, and investment reasonably representative of the interrelationships that will be in place at the time the new rates proposed in a rate case will be in effect”.[30] The commission did not forbid FTY evidence and encouraged the company to consider a *current* test year, an option that it said “might provide a promising mixture of comfort and flexibility acceptable to the parties and the commission.[31]

Public Service filed FTY evidence in a 2008 rate case but the approved settlement in the case was based on historical test year evidence.[32] In May 2009, Public Service again filed FTY evidence as it sought to include in its cost of service some major plant additions,

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[30] PUC Colorado Decision No. C93-1346 in Docket No. 93S-001EG, October 1993, pp. 21-22.
[31] *Ibid*, p. 40.
[32] Docket No. 08S-520E.

including a new coal-fired generating unit and a smart grid build out, which would come online in late 2009 or 2010.[33] A settlement agreement, approved with modifications, based the revenue requirement on a historical 2008 test year with extraordinary adjustments to include the cost of the impending major plant additions. The company agreed not to file a rate case for two years.

This settlement also indicated an expectation that the company would file FTY evidence in its next rate case. It commits the company to provide companion historical test year evidence, including a detailed analysis of deviations between HTY and FTY results. The Company agreed to work with interested parties on reporting requirements with respect to such deviation analyses in order to facilitate the review of future cases.

Idaho

In Idaho the largest electric utility, Idaho Power, successfully used a hybrid test year in a rate case filing in 2003. In a 2009 filing it successfully used a test year beginning in January 2009.[34] This was essentially a current FTY.

Illinois

The move to forward test years is not confined to western states. Illinois utilities have long retained the right to file FTY rate cases and Integrys recently did so successfully for its North Shore Gas and Peoples Gas Light and Coke units.[35] Peoples has a major need to increase replacement investments in its aging system, which serves Chicago.

Michigan

In Michigan, utilities have used varied test year approaches. Recent legislation (2008 PA 286) explicitly sanctions forward test year filings. The law also permits utilities to "self-implement" interim rates if rate cases aren't resolved in 180 days. Consumers Energy and Detroit Edison have recently filed FTY rate cases successfully.

New Mexico

In New Mexico a bill was passed in 2009 that allows the state commission to use forward test years in electric and gas rate proceedings. The bill states that

[33] Docket No. 09AL-299E.
[34] Docket No. IPC-E-09-10.
[35] Dockets No. 09-0166 and 09-0167.

> In making a determination of just and reasonable rates of a utility, the commission shall select a test period that, on the basis of substantial evidence in the whole record, the commission determines best reflects the conditions to be experienced during the period when the rates determined by the commission take effect. If a utility proposes a future test period, a rebuttable presumption shall exist that a future test period best reflects the conditions to be experienced during the period when the rates determined by the commission take effect.[36]

The Bill was supported by majority voice vote of the New Mexico Public Regulation Commission. Public Service of New Mexico recently filed an FTY rate case.

Utah

Utah statutes were amended in 2003 to allow hybrid and forward test years for gas and electric utilities. The amended statutes state that

> If in the commission's determination of just and reasonable rates the commission uses a test period, the commission shall select a test period that, on the basis of the evidence, the commission finds best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect.[37]

The choice of a test year has since become an issue in the early stages of rate cases. In 2004, for example, PacifiCorp [d/b/a Rocky Mountain Power ("RMP")] filed a rate case based on a forward test year. It defended the FTY on the grounds that its costs were increasing due to rapid system growth and a plan to improve system reliability. An unopposed Test Year Stipulation acknowledged that the FTY was the most sensible test year for this case and provided for a task force to address test period procedural issues. The terms of the stipulation were not binding for future proceedings. The Commission commented in its order approving the stipulation that

> Each case needs to be considered on its own merits and the test period selected should be the most appropriate for that case. The test period selected for a utility in a particular case may not be appropriate for another utility or even the same utility in a different case. Some of the factors that need to be considered in selecting a test period include the general level of inflation, changes in the utility's investment, revenues, or expenses, changes in utility services, availability and accuracy of data to the parties, ability to synchronize the utility's investment, revenues, and expenses, whether the utility is in a cost

[36] New Mexico Senate Bill 477, 2009.
[37] Utah Code Annotated Section 54-4-4 (3).

> increasing or cost declining status, incentives to efficient management and operation, and the length of time the new rates are expected to be in effect.[38]

In December 2007, RMP filed a rate case based on a forward test year beginning in July 2008.[39] The Commission instead chose a current FTY beginning in January 2008. The Company was compelled to update its testimony to reflect the sanctioned test year. In its final decision in the case, the Commission instructed the Company to file a semi-annual "variance report" comparing its actual operating results to its rate case forecasts.

In April 2009, RMP filed a notice of intent to file a rate case in June 2009 based on a forward test year beginning in January 2010. A high level of capital investment was emphasized in advocating the need for an FTY. The Commission approved a Test Period Stipulation providing for a current FTY beginning in June 2009. The decision notes that the Division of Public Utilities argued in support of the stipulation that

> the stipulated test period, combined with the opportunity for the Company to request alternative cost recovery treatment for major plant additions, will balance the interest of the Company in reducing regulatory lag and the interests of customers by reducing the risks associated with the timing and cost of major capital additions projected to be completed 18 months into the future.[40]

Wyoming

In Wyoming, a stipulation approved in 2006 provided that RMP (d/b/a PacifiCorp) could, on a one time trial basis, file a rate case based on a forward test year. RMP filed a rate case in June 2007 using an FTY ending in August 2008. The Wyoming Public Service Commission approved a rate settlement based on the forecasts for this test year. They indicated a willingness to hear forward test year evidence in the general rate case but required the company to submit conventional historical test year evidence as well. The Commission also directed the company to prepare a report comparing its actual cost and billing determinants for the current test year to those which the company forecasted in the proceeding. In the event, the variance report stated that the company had overestimated its

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[38] Public Service Commission of Utah, "Order Approving Test Period Stipulation", Docket 04-035-42, October 2004.
[39] Public Service Commission of Utah, "Order on Test Period", Docket No. 07-035-93, February 2008.
[40] Public Service Commission of Utah, "Report and Order on Test Period Stipulation", Docket No. 09-035-23, June 2009.

cost by a small amount but overestimated its revenue and on balance did not earn its allowed rate of return for the year.

In July 2008, RMP filed a new rate case with a current FTY ending in June 2009 using calendar 2007 as a historical reference year. The company emphasized in its case the inability of historical test year rates to compensate the utility for sizable new investments in its system. The Commission approved a settlement that included a provision that RMP file historical test year evidence as well as any FTY evidence in its next rate proceeding.[41] RMP will continue to file operating results that will permit the Commission to review the accuracy of its FTY forecasts.

2.2 Current Status

Table 2 and Figure 1 detail the test year approaches that are currently in use across the United States. It can be seen that historical test years are now used by most large IOUs in less than twenty U.S. jurisdictions. Nearly as many jurisdictions (AL, CA, CT, FL, GA, HI, ME, MI, MN, MS, NY, OR, RI, TN, WI, and the FERC) use forward test years routinely, at least for larger utilities. Forward test years are also used in several Canadian jurisdictions. Four jurisdictions (AR, OH, NJ, & PA) use hybrid test years. An additional 13 jurisdictions are not neatly categorized. Here are some examples.

- Large utilities in Illinois, Kentucky, Maryland, and North Dakota utilities use various test years.
- As previously noted, test years used by utilities in Utah and Wyoming depend on conditions at the time of filing and New Mexico is heading in that direction.

2.3 Conclusions

In Section 1.2 we noted that the matching principle used in historical test year rate cases is based on the assumption that growth in billing determinants matches cost growth so that unit cost is stable. This is true when growth in utility productivity and average use somehow combine to offset the cost impact of input price growth. We report in this chapter that conditions like these have not been normal for electric utilities since the 1960s. Periods of unit cost stability can still occur, but are apt to be followed by periods of rising unit cost.

[41] Wyoming PSC Docket Number 20000-333-ER-08 (Record No. 11824), May 2009.

Table 2

Test Year Approaches of U.S. Jurisdictions

Forward (16)

State	Notes
Alabama	Alabama Power's Rate Stabilization and Equalization Factor is forward looking.
California	
Connecticut	Cost is based on a historical test year that is escalated to a future rate year.
FERC	Rate cases use forward test years while formula rate plans tend to use HTYs.
Florida	
Georgia	
Hawaii	
Maine	Cost is based on a historical test year that is escalated to a future rate year.
Michigan	
Minnesota	
Mississippi	
New York	
Oregon	
Rhode Island	Cost is based on a historical test year that is escalated to a future rate year.
Tennessee	
Wisconsin	

Hybrid (4)

State	Notes
Arkansas	
Ohio	
New Jersey	
Pennsylvania	

Transitional/Varying (13)

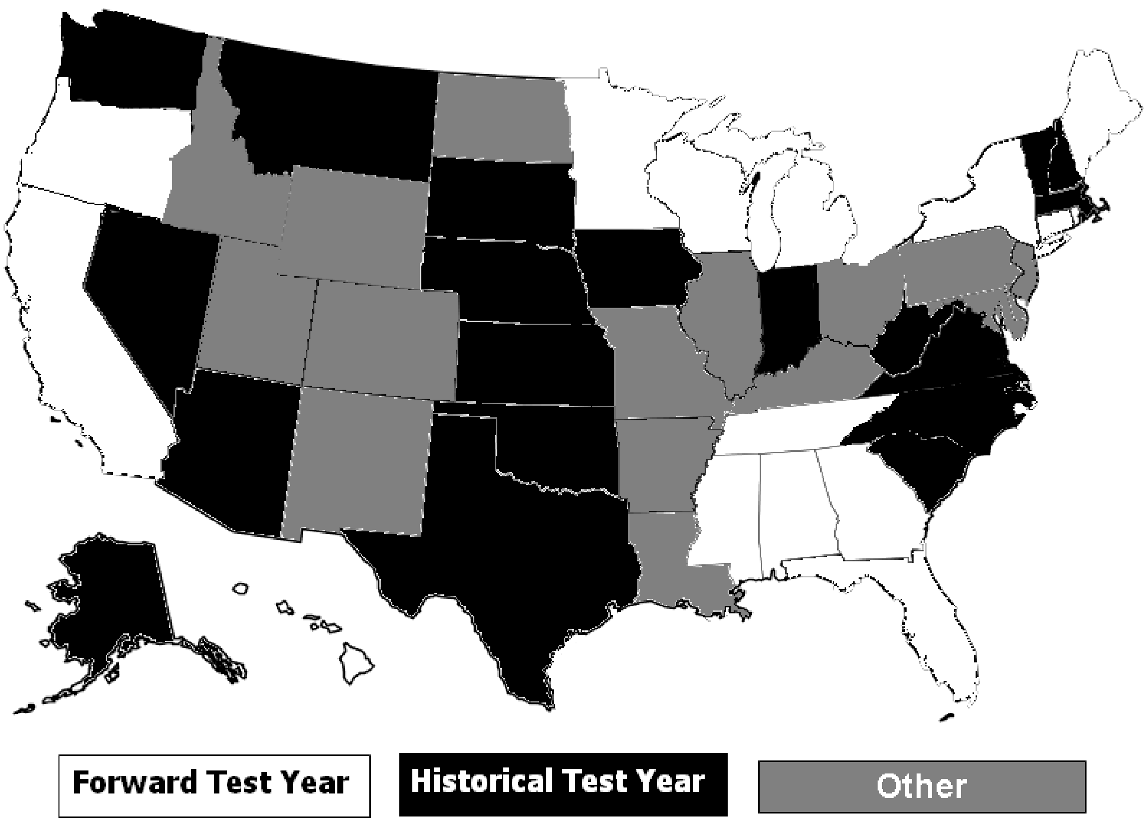
Utility Name	Notes
Colorado	Public Service of Colorado can file FTY evidence. No FTY rates have yet been approved but the most recent case made extraordinary HTY adjustments.
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently.
Delaware	Before restructuring FTY filings were common, but companies have used HTY in recent filings.
Idaho	
Illinois	Historic test years are the norm in IL. However, utilities have the right to make FTY filings and an FTY was accepted in a recent rate case of the Integrys gas utilities.
Kentucky	FTYs are legally authorized, but only Duke Energy has utilized them to date.
Louisiana	Cleco Power frequently uses hybrid test years. Entergy New Orleans recently had a hybrid test year approved via settlement.
Maryland	Baltimore Gas & Electric tends to file hybrid test years while other utilities tend to file historical test years.
Missouri	Utilities have the option to file hybrid year forecasts that are trued up during the course of the proceeding.
New Mexico	Recently passed law allows for use of FTY, but no rate case with an FTY has yet been approved.
North Dakota	Utilities use various test years including FTYs.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently had FTYs approved.

Historical (19)

Utility Name	Notes
Alaska	
Arizona	
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs in its jurisdiction. Gas companies are legally authorized to use FTYs, but no gas company has had FTY rates approved.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

Figure 1

Map of Jurisdictions by Approved Test Year



Numerous regulators have moved away from historical test years in periods when unit cost is rising. Historical test year jurisdictions are now in the minority.

3. EMPIRICAL SUPPORT FOR FORWARD TEST YEARS

3.1 Unit Cost Trends of U.S. Electric Utilities

In Section 1.2 we detailed the key role that the trend in the unit cost of utilities has in determining the reasonableness of historical test years and the need for forward test years. In original research for this paper, we have calculated the unit cost trends of a sample of vertically integrated electric utilities ("VIEUs"). In this section, we explain our research methods in some detail before discussing the results.

3.1.1 Data

The primary source of utility cost date used in the study was the FERC Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Unit cost calculations also require data on billing determinants. Data on the number of customers served were drawn from FERC Form 1. Data on delivery volumes were drawn from Form EIA 861. The FERC Form 1 and Form EIA 861 data used in this study were gathered by SNL Financial, a respected commercial vendor.

Data were considered for inclusion in the sample from all major investor-owned VIEUs that did not offer gas distribution service or sell or spin off the bulk of their transmission assets in recent years. To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from the thirty four companies listed in Table 3 were used in the unit cost research. The sample period was 1996-2008. The year 2008 is the latest for which the requisite data were available when the study was prepared.

Supplemental data sources were used to measure input price trends. Handy Whitman indexes were used to measure electric utility construction cost trends. Global Insight indexes were used to measure trends in the prices of electric utility materials and services. Employment cost indexes prepared by the BLS were used to measure trends in labor prices. Regulatory Research Associates data was used to measure trends in target ROEs approved by regulators.

Table 3

Utilities Included in the Unit Cost Research

Company
Alabama Power
Appalachian Power
Arizona Public Service
Black Hills Power
Carolina Power & Light
Cleco Power
Columbus Southern Power
Dayton Power and Light
Duke Energy Carolinas
Empire District Electric
Entergy Arkansas
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Idaho Power
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Minnesota Power
Mississippi Power
Nevada Power
Ohio Power
Oklahoma Gas and Electric
Otter Tail Power
PacifiCorp
Portland General Electric
Public Service Company of Oklahoma
Southwestern Electric Power
Southwestern Public Service
Tampa Electric
Tucson Electric Power
Virginia Electric and Power

Number of utilities in sample: 34

3.1.2 Definition of Unit Cost

In Section 1.2.1 we discussed a measure of unit cost growth that is relevant in the appraisal of test years. It is constructed by taking the difference between growth in the net cost of base rate inputs and the growth in an index of utility billing determinants. For each sampled utility, we calculated the total cost of base rate inputs net of taxes as the sum of non-energy O&M expenses, depreciation, amortization, and return on rate base. Non-energy O&M expenses were calculated as total O&M expenses less customer service and information expenses and energy expenses that included those for steam power generation fuel, nuclear power generation fuel, other power generation fuel, and purchased power.[42] [43]

Return on rate base was calculated as the value of the rate base times a weighted average cost of capital ("WACC"). In constructing the WACC we assumed 50/50 weights for debt and common equity. The rate of return on debt was calculated as the ratio of the interest payments of electric utilities to the value of their debt as reported on the FERC Form 1. The ROE was calculated as the average applicable allowed ROEs of electric utilities as reported by Regulatory Research Associates.[44] The rate base for each utility was calculated as its net plant value less net accumulated deferred income taxes plus the value of its fuel, material, and supply inventories.

We reduced the base rate cost thus calculated by two kinds of "non-core" revenues, as is common in the calculation of retail base rate revenue requirements. One item deducted was Other Operating Revenue. This is the revenue from miscellaneous goods and services that include bulk power wheeling. The other component of non-core revenues was an estimate of the margin from power sales for resale.[45]

The growth in the billing determinant index used in our study is a weighted average of the growth in important billing determinants of electric utilities. The determinants used in index construction were the numbers of residential, commercial, and other retail customers

---

[42] Customer service and information expenses were excluded because they tended to rise over the sample period due to expanding demand-side management programs. The cost of DSM programs is typically recovered using tracker-rider mechanisms.
[43] We also excluded the Other Expenses category of Other Power Supply Expenses. We believe that large and volatile commodity-related costs are sometimes reported in this category.
[44] In this calculation, we assumed that the target ROE approved for a utility in its most recent rate case was applicable until a new target ROE was approved.
[45] These margins were computed as the difference between sales for resale revenue and an estimate of the energy commodity costs used in power supply.

and the corresponding delivery volumes.[46] We weather normalized the volumes using econometric demand research. In constructing the index, the trends in the billing determinants thus assembled were weighted by our estimates of the typical shares of individual billing determinants in the base rate revenue requirements of VIEUs.[47] The estimates were drawn from a perusal of recent VIEU rate case filings.

3.1.3 Unit Cost Results

Unit Cost Trends

The average annual trends of the sampled utilities in their cost, billing determinants, and unit cost can be found in Table 4 and Figure 2. It can be seen that unit cost declined by a modest 0.78% annually on average in the 1996-2002 period as average growth in billing determinants exceeded average growth in cost. The average growth in unit cost was positive in only one year of this period. These results suggest that, under typical operating conditions, historical test years would have yielded compensatory outcomes in rate cases during this period.

In the 2003-2008 period, on the other hand, it can be seen that unit cost grew briskly, averaging about 2.31% annually. Utilities experienced unit cost growth on average in every year of the period. Cost averaged 1.98% annual growth from 1996 to 2002 and 4.36% annual growth thereafter. The normalized growth of billing determinants averaged 2.75% per annum through 2002 but only 2.05% per annum thereafter. Thus, growth in billing determinants slowed despite marked acceleration of cost growth.

Earnings Impact

To consider the earnings attrition resulting from 2.3% annual unit cost growth, consider that if the typical company in the sample earned its target ROE it would constitute about 13% of the total cost of its base rate inputs. Assuming two years of 2.3% unit cost growth, revenue based on prices reflecting only the normalized business conditions of the historical test year would be expected to result in a 4.45% base rate revenue shortfall. If there was no tax adjustment, this would reduce the return on equity by about 35%. Assuming

[46] The retail peak demands of commercial and industrial customers are also important billing determinants but data on these were unavailable.
[47] We assigned the base rate revenue shares corresponding to demand charges to the "other retail" delivery volume, expecting that these volumes have trends that are similar to those of demand charge billing determinants.

Table 4

Trends in the Unit Cost of US Vertically Integrated Utilities

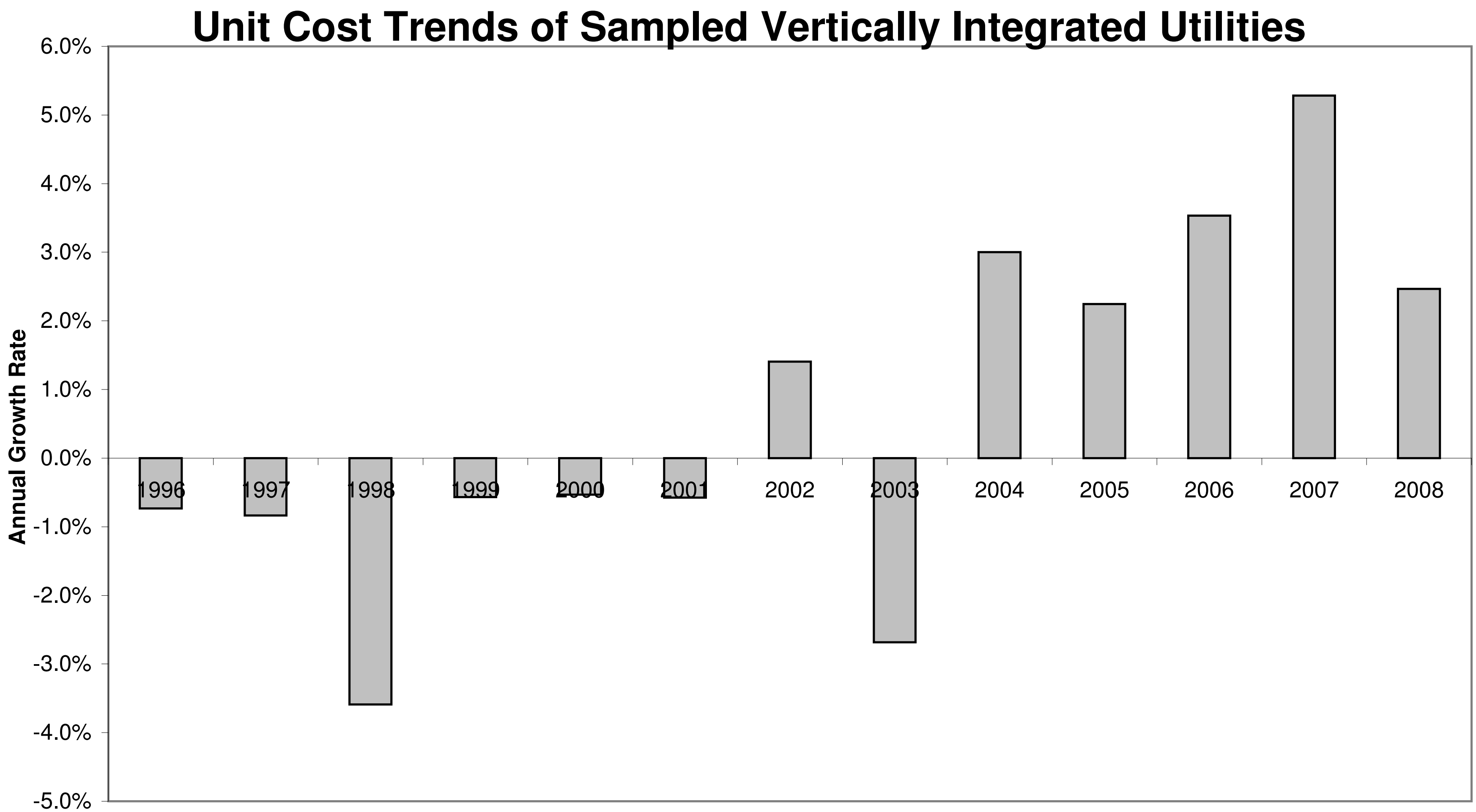
Sample Average Annual Growth Rates, Unweighted

Year	**Cost**[1]	**Billing Determinants**[2]	**Unit Cost**
1996	2.8%	3.5%	-0.7%
1997	1.4%	2.2%	-0.8%
1998	-0.7%	2.9%	-3.6%
1999	2.5%	3.0%	-0.6%
2000	3.4%	4.0%	-0.5%
2001	0.9%	1.4%	-0.6%
2002	3.6%	2.2%	1.4%
2003	1.6%	4.3%	-2.7%
2004	4.6%	1.6%	3.0%
2005	4.0%	1.8%	2.2%
2006	5.0%	1.5%	3.5%
2007	7.9%	2.6%	5.3%
2008	3.0%	0.5%	2.5%
Average Annual Growth Rates			
1996-2008	**3.08%**	**2.43%**	**0.65%**
1996-2002	**1.98%**	**2.75%**	**-0.78%**
2003-2008	**4.36%**	**2.05%**	**2.31%**

[1] The net cost formula is (Total O&M Expenses - Energy O&M Expenses - Customer Service and Information Expenses) + (Depreciation + Amortization + WACC x Rate Base) - (Other Operating Revenues + Estimated Resale Margin). The source of the cost data is FERC Form 1.

[2] The annual growth in billing determinants is a weighted average of the growth in residential, commercial, and other retail delivery volumes and customers served. The weights are shares in the base rate revenue requirement that are typical of vertically integrated electric utilities. Volumes were weather normalized by PEG Research using econometric demand modelling. The source of the raw volume data is Form EIA 861. The source of the customer data is FERC Form 1.

Figure 2


Unit Cost Trends of Sampled Vertically Integrated Utilities
Annual Growth Rate
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

an allowed ROE of 11%, this would mean a drop in ROE of around 375 basis points before tax adjustments. While lower income taxes would mitigate the earnings impact, we may conclude from this analysis that historical test years would have been inherently non-compensatory for a utility operating under the *typical* business conditions facing VIEUs in recent years. Results would be much worse for utilities facing more pronounced unit cost pressures due, for example, to an accelerated program of replacement capex or a large scale DSM program.

Unit Cost Drivers

Input Prices Our discussion in Section 1.2.1 contained the result that input price inflation, productivity growth, and the trend in average use were key drivers of unit cost growth. We calculated for this report indexes of the inflation in the prices of base rate inputs faced by the sampled VIEUs. The growth rates of the summary input price indexes are weighted averages of the growth rates in indexes of prices for electric utility plant and O&M labor and materials and services. The index for each utility uses as weights the share of each input group in the total cost of the company's base rate inputs.[48] The index for the price of plant was calculated from the trends in bond yields, allowed returns on equity, and the Handy Whitman Construction Cost Index for vertically integrated electric utilities in the applicable region.

Results of our input price research are presented in Table 5 and Figure 3. It can be seen that the prices of base rate inputs averaged 2.76% annual inflation in the 1996-2002 period and 3.65% inflation in the 2003-2008 period --- an increase of 89 basis points. The price acceleration was primarily in materials and services and capital. M&S price inflation averaged 2.08% annually in the 1996-2002 period and 4.31% annually in the 2003-2008 period.

[48] An input price index with cost share weights effectively estimates the impact of price inflation on cost.

Table 5

Trends in Prices of Electric Utility Base Rate Inputs, 1996-2008

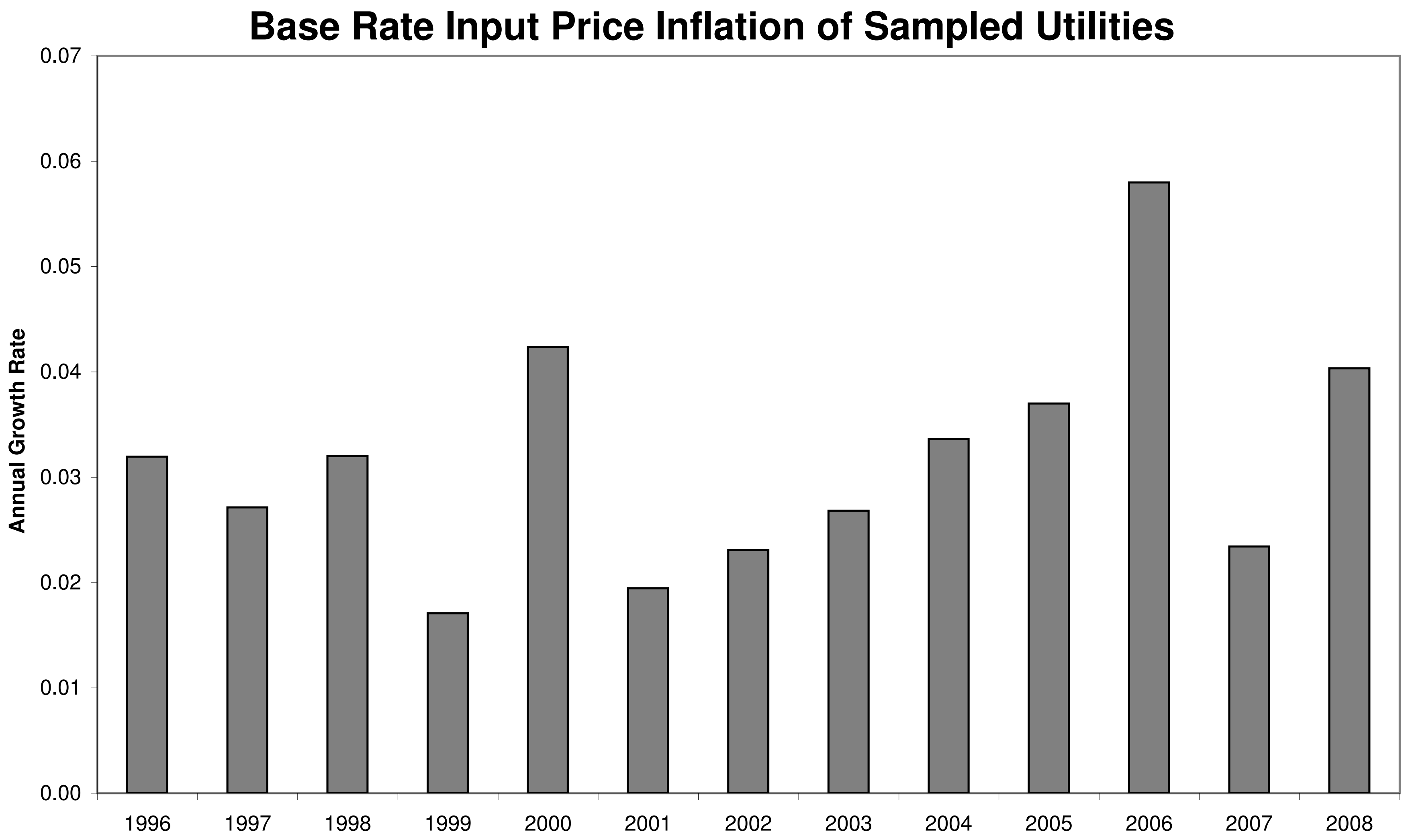
	Summary Input Price Index		Labor		Materials & Services		Capital	
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
1995	1.000		1.000		1.000		1.000	
1996	1.032	3.2%	1.033	3.2%	1.020	2.0%	1.034	3.3%
1997	1.061	2.7%	1.065	3.1%	1.042	2.1%	1.061	2.7%
1998	1.095	3.2%	1.108	4.0%	1.058	1.6%	1.098	3.4%
1999	1.114	1.7%	1.139	2.7%	1.076	1.6%	1.112	1.2%
2000	1.162	4.2%	1.193	4.6%	1.109	3.0%	1.158	4.1%
2001	1.185	1.9%	1.242	4.0%	1.135	2.4%	1.168	0.8%
2002	1.213	2.3%	1.301	4.6%	1.157	1.9%	1.186	1.5%
2003	1.246	2.7%	1.356	4.2%	1.189	2.7%	1.206	1.7%
2004	1.289	3.4%	1.428	5.1%	1.241	4.3%	1.227	1.7%
2005	1.337	3.7%	1.501	5.0%	1.303	4.9%	1.251	1.9%
2006	1.417	5.8%	1.652	9.6%	1.364	4.6%	1.303	4.1%
2007	1.451	2.3%	1.578	-4.6%	1.421	4.1%	1.352	3.6%
2008	1.510	4.0%	1.629	3.2%	1.498	5.3%	1.396	3.2%
Average Annual Growth Rate								
1996-2008		**3.17%**		**3.76%**		**3.11%**		**2.57%**
1996-2002		**2.76%**		**3.76%**		**2.08%**		**2.43%**
2003-2008		**3.65%**		**3.75%**		**4.31%**		**2.72%**

Sources

Labor	Calculated by PEG Research from BLS Employment Cost Indexes that include pensions and benefits
Materials & Services	Calculated by PEG Research using functional cost shares for sampled utilities obtained from FERC Form 1 and detailed electric utility M&S price indexes obtained from Global Insight's *Power Planner.*
Capital	Calculated by PEG Reseach from Handy Whitman electric utility construction cost indexes Average yields on utility bonds calculated from FERC Form 1 data gathered by SNL Interactive Applicable allowed ROEs as reported by Regulatory Research Associates
Summary	Calculated by PEG Research from the labor, M&S, and capital price indexes using vertically integrated electric utility base rate input cost shares drawn from FERC Form 1

FERC Form 1 data gathered by SNL

Figure 3


Base Rate Input Price Inflation of Sampled Utilities
Annual Growth Rate
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

Plant Additions Large plant additions were noted in Section 1.2.1 to be an important driver of utility productivity growth. Table 6 and Figure 4 describe the trend in real (*i.e.* inflation adjusted) plant additions per customer of the sampled utilities. It can be seen that from 2003 through 2008, real plant additions were 25% higher on average than in the 1995-2002 period.

Average Use In Table 7 and Figure 5 we present information on the trends in weather normalized average use by the residential and commercial customers of a large sample of U.S. electric utilities from 1996 to 2008. The sample included specialized transmission and distribution utilizes as well as VIEUs. It can be seen that the growth rates in average use have tended to fall for both residential and commercial customers since 2002. The trend was more pronounced for residential customers. Growth in normalized average use of power by residential customers averaged 1.09% per year in the 1996-2002 period and 0.43% per year in the 2003-2008 period. Growth in weather-normalized average use by commercial customers averaged 1.04% per year in the 1996-2002 period and 0.74% per year in the 2003-2008 period.

The average use slowdown was especially pronounced in the 2006-2008 period. The normalized average use of residential customers averaged a slight 0.19% annual decline and average use by commercial customers was essentially flat. For this more recent period, we separately calculated trends for utilities in service territories with large DSM programs and the trends for utilities in other territories. The normalized average use by residential customers of utilities operating in territories with large DSM programs declined by a remarkable 0.68% on average.

These results suggest that the typical IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs. Forward test years will be particularly uncompensatory where utilities must cope with the consequences for load of aggressive DSM programs.

Table 6

Real Plant Additions Per Customer of Sampled Utilities

	Real Additions to Plant in Service (1995=100)	Number of Customers (1995=100)	Real Additions per Customer (1995=100)
1995	100.00	100.00	100.00
1996	93.26	101.89	91.53
1997	85.99	103.99	82.70
1998	70.50	106.33	66.30
1999	89.82	108.20	83.01
2000	102.31	110.66	92.46
2001	111.46	112.80	98.81
2002	108.46	114.70	94.56
2003	148.32	116.57	127.23
2004	110.42	118.78	92.96
2005	115.52	120.98	95.49
2006	125.04	123.89	100.93
2007	149.51	125.82	118.83
2008	165.19	126.85	130.22
Averages			
1996-2002			87.05
2003-2008			110.94

Sources: Cost and cutomer data from FERC Form 1. Plant additions deflated using applicable regional Handy Whitman electric utility construction cost indexes.

Figure 4

Real Plant Additions per Customer of Sampled Utilities

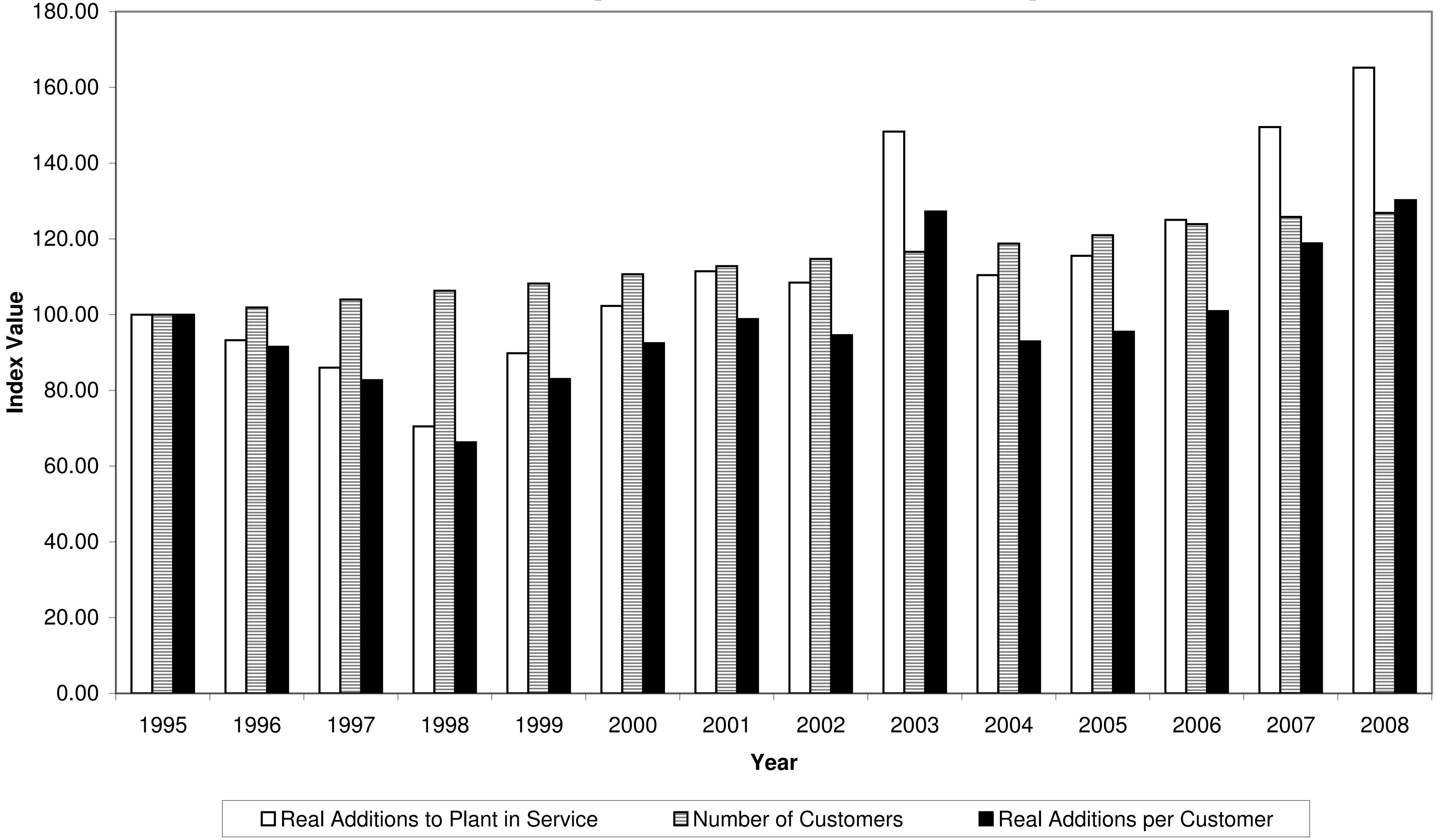


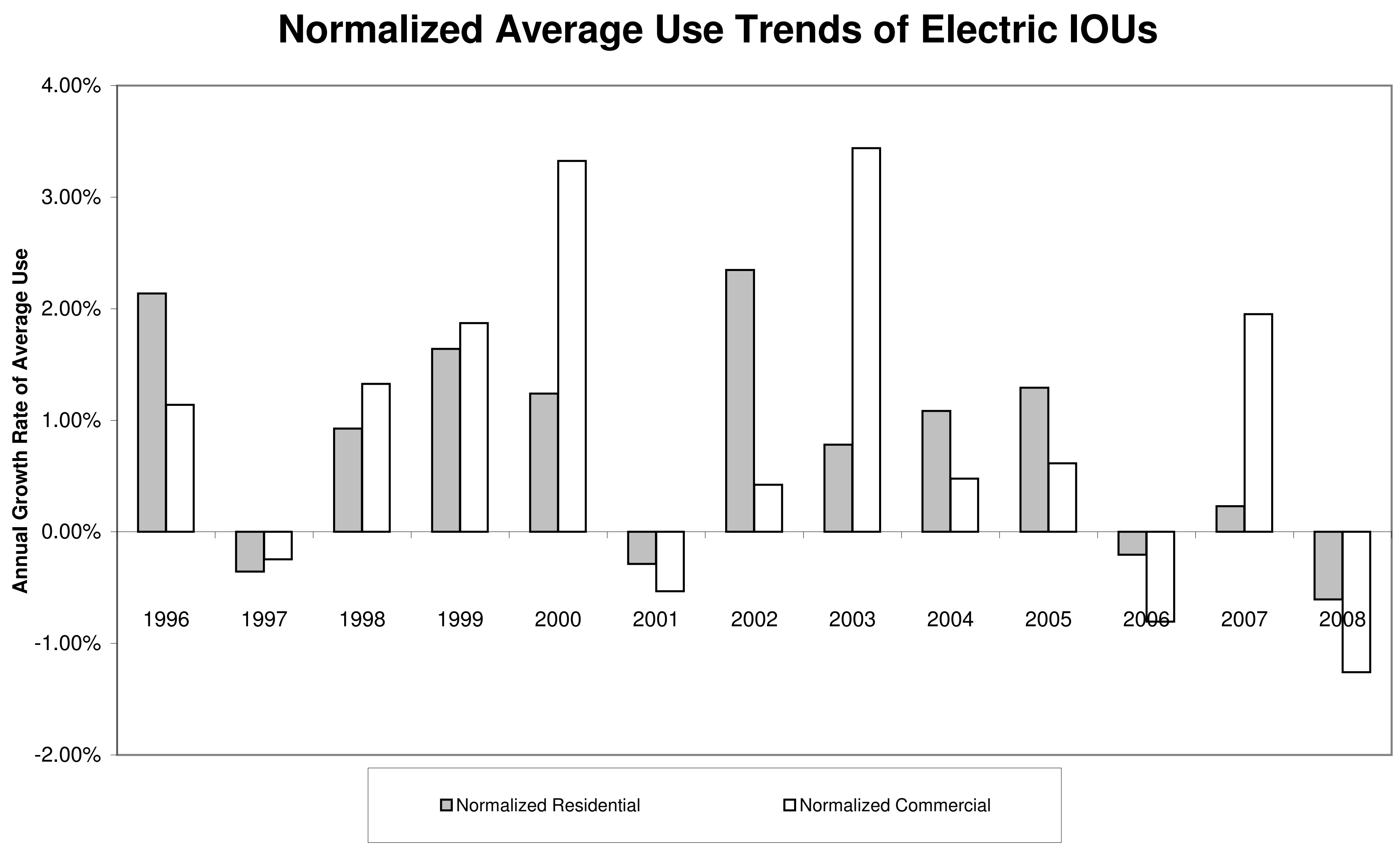
Table 7

Trends in Average Use by Residential & Commercial Customers of Investor-Owned Electric Utilities

Year	Residential Raw	Residential Normalized	Commercial Raw	Commercial Normalized
1996	1.10%	2.14%	0.68%	1.14%
1997	-2.35%	-0.36%	-0.43%	-0.25%
1998	1.39%	0.93%	1.91%	1.33%
1999	1.66%	1.64%	1.63%	1.87%
2000	2.02%	1.24%	3.20%	3.33%
2001	-0.65%	-0.29%	-0.35%	-0.53%
2002	4.18%	2.35%	0.71%	0.42%
2003	-0.71%	0.78%	2.88%	3.44%
2004	0.03%	1.08%	0.35%	0.48%
2005	4.02%	1.29%	1.24%	0.61%
2006	-2.86%	-0.21%	-1.06%	-0.80%
2007	2.68%	0.23%	2.26%	1.95%
2008	-1.95%	-0.61%	-1.83%	-1.26%
Average Annual Growth Rate				
1996-2008	**0.66%**	**0.79%**	**0.86%**	**0.90%**
1996-2002	**1.05%**	**1.09%**	**1.05%**	**1.04%**
2003-2008	**0.20%**	**0.43%**	**0.64%**	**0.74%**
2006-2008	**-0.71%**	**-0.19%**	**-0.21%**	**-0.04%**
High DSM utilities	**-1.07%**	**-0.68%**	**-0.19%**	**-0.08%**
Other utilities	**-0.54%**	**0.05%**	**-0.22%**	**-0.02%**

Sources: Customer data from FERC Form 1. Volume data from Form EIA 861. Volumes were weather normalized by PEG Research using econometric demand modelling.

Figure 5


Normalized Average Use Trends of Electric IOUs
Annual Growth Rate of Average Use
4.00%
3.00%
2.00%
1.00%
0.00%
-1.00%
-2.00%
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Normalized Residential
Normalized Commercial

3.2 How Test Years Affect Credit Quality Metrics

Table 8 presents results for selected credit quality metrics for a large sample of electric utilities. The reported metrics are averages for the 2006-2009 period. The source is *Credit Stats: Electric Utilities—U.S.*, a report appearing in the Global Credit Portal of Standard & Poor's RatingsDirect. We present results for four credit metrics: Standard & Poor's corporate credit rating, the (rate of) return on capital, and two cash flow ratios (EBITDA interest coverage and FFO/Debt).

Cash flow ratios are used by credit analysts to assess a utility's ability to service debt. The cash flow measures are normally calculated as adjustments to net income that add back cash flows that could be used to service debt. FFO (funds from operations), for instance, adds back depreciation and amortization expenses. EBITDA (earnings before interest, taxes, depreciation, and amortization) adds back interest and tax payments as well as depreciation and amortization.

Table 8 reports averages for each of the numerical metrics for utilities that operated under historical, hybrid, and forward test years throughout the 2006-2008 period. There is also an indeterminate category for utilities that are not easily categorized as having operated under one kind of test year during this period.

Caution must be taken in making comparisons inasmuch as these metrics may differ between the sampled utilities due to differences in several other business conditions as well as to any differences in test years. The other relevant business conditions include the ability to rate base construction work in progress, the local severity of the 2008 recession, and whether or not utilities operated under formula rates and/or revenue decoupling. Despite these complications, the samples are large and diverse enough to shed some light on the effect that test years have on credit metrics.

Comparing the results, it can be seen that the values of all four credit metrics were typically much more favorable for the *forward* test year utilities than for the *historical* test year utilities.

- The forward test year utilities had a typical credit rating between BBB+ and A- whereas the historical test year utilities had a typical credit rating between BBB- and BBB.

Table 8

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Historical Test Years		**7.9**	**4.2**	**18.2**
AEP Texas Central	BBB	6.9	2.8	8.7
AEP Texas North	BBB	8.1	4.9	21.0
Appalachian Power	BBB	6.0	2.9	9.5
Arizona Public Service	BBB-	7.3	4.6	19.3
Black Hills Power	BBB-	9.6	4.8	25.3
Carolina Power & Light	BBB+	11.3	5.9	25.0
CenterPoint Energy Houston Electric	BBB	9.8	6.2	24.4
Central Illinois Light	BBB-	9.5	8.2	29.5
Central Illinois Public Service	BBB-	4.9	3.6	15.7
Central Vermont Public Service	BB+	7.0	2.7	12.8
Commonwealth Edison	BBB-	6.4	3.1	12.1
Duke Energy Carolinas	A-	7.0	6.1	28.5
Duke Energy Indiana	A-	8.0	5.1	21.3
El Paso Electric	BBB	9.4	4.2	18.8
Entergy Gulf States	BBB	7.2	2.8	25.1
Entergy Louisiana	BBB	6.6	3.2	36.3
Entergy Texas	BBB	5.6	2.5	14.0
Interstate Power & Light	BBB+	10.5	5.5	24.4
IPALCO Enterprises (Indianapolis Power & Light)	BB+	13.2	3.4	12.9
Kentucky Power	BBB	6.5	3.5	13.8
MidAmerican Energy	A-	10.7	5.5	22.7
Nevada Power	BB	8.4	2.6	11.1
NSTAR Electric	A+	10.2	7.7	21.6
Oklahoma Gas & Electric	BBB+	10.0	6.4	25.2
Oncor Electric Delivery	BBB+	9.6	4.4	17.9
Public Service Company of Colorado	BBB+	8.1	4.3	19.6
Public Service Company of New Hampshire	BBB	8.4	4.8	13.7
Public Service Company of New Mexico	BB-	3.9	2.3	8.6
Public Service Company of Oklahoma	BBB	4.9	2.7	18.3
Puget Sound Energy	BBB	7.5	3.8	13.7
Sierra Pacific Power	BB	7.4	2.9	12.7
South Carolina Electric & Gas	BBB+	8.3	4.7	21.1
Southern Indiana Gas & Electric	A-	9.5	5.4	22.8
Southwestern Electric Power	BBB	7.4	3.5	15.4
Southwestern Public Service	BBB+	5.3	3.5	12.1
Texas-New Mexico Power	BB-	5.3	3.3	9.5
Tuscon Electric Power	BB+	8.4	3.2	17.9
Westar Energy	BBB-	6.7	3.9	14.8
Western Massachusetts Electric	BBB	5.8	3.7	11.8
Hybrid Test Years		**9.5**	**5.9**	**19.9**
Atlantic City Electric	BBB	9.6	4.4	34.2
Baltimore Gas & Electric	BBB	6.8	4.3	11.1
Cleveland Electric Illuminating	BBB	13.3	4.3	9.2
Cleco Power	BBB	8.3	3.7	10.9
Columbus Southern Power	BBB	13.5	6.5	23.3
Dayton Power & Light	A-	16.3	16.1	42.9
Duke Energy Ohio	A-	5.2	6.3	25.5
Entergy Arkansas	BBB	6.7	5.6	27.7
Idaho Power	BBB	6.6	3.8	10.7
Jersey Central Power & Light	BBB	8.3	8.5	22.9
Metropolitan Edison	BBB	9.3	6.7	12.7
Ohio Edison	BBB	9.4	4.6	14.5
Ohio Power	BBB	8.2	4.3	15.0
PECO Energy	BBB	10.5	7.0	19.5
Pennsylvania Electric	BBB	8.9	5.5	15.8
PPL Electric Utilities	A-	9.5	4.6	18.6
Public Service Electric & Gas	BBB	8.7	4.9	14.9
Toledo Edison	BBB	11.9	5.2	28.0

Table 8, continued

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Forward Test Years		**9.2**	**5.1**	**21.0**
ALLETE (Minnesota Power)	BBB+	10.8	5.1	19.5
Central Hudson Gas & Electric	A	9.6	4.9	14.9
Central Maine Power	BBB+	8.2	5.3	17.8
Connecticut Light & Power	BBB	6.7	4.3	12.2
Detroit Edison	BBB	8.2	4.9	16.8
Entergy Mississippi	BBB	7.2	4.3	27.1
Florida Power & Light	A	9.9	7.0	30.7
Florida Power Corp.	BBB+	9.9	4.5	19.0
Georgia Power	A	10.1	5.9	22.6
Gulf Power	A	9.7	5.6	19.2
Hawaiian Electric	BBB	7.1	4.4	15.3
Mississippi Power	A	11.6	8.9	35.5
Northern States Power - MN	BBB+	9.4	4.9	22.9
Northern States Power - WI	A-	8.8	5.9	26.6
Pacific Gas & Electric	BBB+	10.7	4.0	23.3
PacifiCorp	A-	7.9	4.0	17.3
Portland General Electric	BBB+	7.9	4.1	19.2
Rochester Gas & Electric	BBB	9.4	3.8	19.4
Southern California Edison	BBB+	11.4	4.0	19.3
Tampa Electric	BBB	9.6	4.5	21.0
Wisconsin Electric Power	A-	6.9	5.4	14.6
Wisconsin Power & Light	A-	10.1	5.0	24.7
Wisconsin Public Service	A-	9.8	5.6	23.8
Indeterminate		**7.8**	**4.3**	**18.1**
Alabama Power	A	9.5	5.7	21.5
Empire District Electric	BBB-	7.3	3.5	15.7
Indiana Michigan Power	BBB	6.7	3.5	15.4
Kansas City Power & Light	BBB	7.9	4.8	19.4
Potomac Electric	BBB	7.4	4.4	20.6
Southwestern Electric Power	BBB	7.4	3.5	15.4
Union Electric	BBB-	8.2	4.4	18.4
All Companies		**8.6**	**4.8**	**19.3**

Source: Standard & Poor's Ratings Direct, *Credit Stats: Electric Utilities - U.S.* August 24, 2009. Financial metrics are averages of the years 2006-2008.

- The forward test year utilities had an average return on capital of 9.2% whereas the historical test year utilities had an average return of 7.9%.
- The forward test year utilities had an average EBITDA/interest coverage of 5.1 whereas the historical test year utilities had an average coverage of 4.2
- The forward test year utilities had an average FFO/debt ratio of 21.0% whereas the historical test year utilities had an average ratio of 18.2%.

Additional insights concerning the effect of forward test years on credit quality can be found in another recent Standard & Poor's report.[49] The study sought to rank state regulatory regimes with respect to their effect on credit quality. Of the fourteen states covered by the study which had well-established forward test year traditions at the time of the study, the author found five to be "more credit supportive", six to be "credit supportive", only two to be "less credit supportive", and none to be "least credit supportive". In contrast, of the seventeen states covered by the study that had well-established historical test year conditions, only three were categorized as "more credit supportive", seven were categorized as "credit supportive", six were categorized as "less credit supportive" and one was categorized as "least credit supportive".

3.3 Incentive Impact of Forward Test Years

In Section 1.2.4 we noted that the incentive impact of forward test years has been an issue in some proceedings. We argued, based on our experience in the field of incentive regulation, that the incentive impact of forward and historical test years should be similar on balance. To test the hypothesis that the choice of a test year has no impact on operating efficiency, PEG Research measured the trends in the O&M expenses of a large group of VIEUs over the 1996-2008 sample period. O&M expenses are a better focus than the total cost of base rate inputs in such a study because some utilities had greater needs than others for major plant additions and these needs had little to do with the kind of test year in a jurisdiction. Differences in cost growth are due in part to differences in output growth, so we divided O&M expenses by three alternative output metrics: generation volumes, generation capacity, and the number of customers served. We calculated how the trends in the three cost metrics differed for utilities operating under three kinds of test years: historical, hybrid, and

[49] Todd Shipman, *Assessing U.S. Utility Regulatory Environments*, Standard & Poor's Ratings Direct, November 2008.

forward. If forward test years weaken operating efficiency, we would expect the growth in the cost metrics to be higher on average for the forward test year utilities.

Results of this exercise are reported in Table 9. It can be seen that, using all three cost metrics, the cost trends of the forward test year utilities were similar to --- and a little slower than --- those of the historical test year utilities and of the full utility sample. These results are consistent with the notion that there is no significant difference in the incentives to contain cost that are generated by future and historical test years.

Table 9

Trends in Unit Non-Fuel O&M Expenses by Test Year, 1996-2008

	Test Year Type			
	Historic	Partial	Forward	All
Cost/Customer	2.1%	2.0%	1.9%	2.2%
Cost/Generation Volume	2.2%	3.0%	1.4%	2.3%
Cost/Generation Capacity	1.9%	3.2%	1.3%	1.9%

Source: Federal Energy Regulatory Commission (FERC) Form 1 and Form EIA-876 data gathered by SNL Financial.

4. CONCLUDING REMARKS

Having established in some detail in the chapters above the financial stresses imposed on U.S. electric utilities by historical test years today, we provide in this chapter some concluding remarks on action plans for regulators who wish to move forward with sensible remedies.

4.1 Sensible First Steps

In states where regulators are interested in experimenting with forward test years but not yet prepared to "make the plunge" to large scale adoption, our discussion has identified a number of cautious first steps down the road that limit the risk of bad outcomes but permit the regulatory community to learn more about FTY pros and cons.

- Allow a forward test year on a trial basis for one interested utility.
- Allow forward test years on an occasional basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable. A ruling on the test year issue can precede the preparation of a rate case, as in Utah.
- Borrow a few of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, HTY O&M expenses and/or plant addition costs can be adjusted for forecasts of price inflation prepared by respected independent agencies. Residential and commercial delivery volumes can be adjusted for recent average use trends. Special adjustments can be made for looming major plant additions.
- Try current FTYs, which involve forecasts only one year into the future. Current test years can be combined with interim rate increases at the outset a rate case which are subject to true up when new rates are ultimately approved. The combination of current test years and interim rates is a salient option because it eliminates regulatory lag without a two year forecast.

4.2 Alternative Remedies for Test Year Attrition

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems that they sometimes cause, a variety of alternative measures are available to relieve the financial attrition that can result from using historical test years in a rising unit cost environment.

1. HTY calculations can incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Utilities can be permitted to implement interim rate increases. Interim rates can effectively reduce regulatory lag by a year. States that permit interim rates include HI, IA, MI, MO, NH, OK, TX, VA, and WI.
3. Capital spending trackers can ensure timely commencement of the recovery of costs of plant additions, without rate cases, when assets become used and useful. Trackers can be designed to maintain incentives for good capital cost management and timely project completion. Monitoring by PEG Research reveals that capital spending trackers have been approved for use by energy utilities in AR, CA, FL, GA, IA, ID, IL, IN, KS, KY, MD, ME, MN, MO, NJ, NY, OH, OK, OR, PA, TX, VA, and WI.
4. The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.
5. Cost trackers can also adjust rates automatically to ensure timely recovery of O&M expenses that are unusually volatile and/or expected to rise rapidly. Expenses that are often recovered using trackers include those for pensions and benefits, uncollectible bills, and DSM.
6. Several methods have been established to compensate utilities for slowing growth in average use.
    - Lost revenue adjustment mechanisms (a/k/a lost margin trackers) restore margins that are estimated to have been lost because of utility conservation programs. These are currently used by electric utilities in CT, IN, KY, OH, NC, and SC.

- Decoupling true-up plans help base rate revenue track revenue requirements more closely and can thereby restore lost margins that result from slow growth in average use resulting from a wider variety of sources, including conservation programs administered by independent agencies. Such plans are currently used by electric utilities in CA, CT, DC, HI, ID, MA, MD, MI, NY, OR, VT, and WI. They are used by gas utilities in several additional states (*e.g.* AR, CO, IN, MN, NJ, NC, UT, VA, WA, and WY).
- Higher customer charges are also effective in reducing attrition from declining average use. Straight fixed variable pricing, which recovers *all* fixed costs using fixed charges, is used by gas utilities in GA, MO, OH, OK, and ND.

7. The duration of rate cases can be limited. A reasonable cap is the average length of cases in the United States, which is currently between nine and ten months.[50]
8. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth. Such plans typically have a duration of three to five years, and terms of seven to ten years have been approved. Even if an historical test year makes the initial rates under such plans non-compensatory, it would only happen once in a multiyear period. Utilities would have several years to recoup their losses through superior productivity growth --- and an incentive to do so. North American jurisdictions where multiyear rate plans are common include CA, ME, MA, NY, OH, and VT in the United States and Alberta, British Columbia, and Ontario in Canada. This approach to ratemaking is more the rule than the exception overseas.

[50] See *EEI 2007 Financial Review*, p. 36.

APPENDIX: UNIT COST LOGIC

To better understand the conditions that can cause historical test year rates to produce earnings attrition, suppose that year t is a rate year (a year when new rates take effect) and that the utility is underearning with its newly implemented HTY rates. The cost of base rate inputs then exceeds base rate revenue and the ratio of cost to revenue is positive.

$$Cost_t / Revenue_t > 0.$$

To simplify the story, suppose next that the utility has only one service and the base rate for that service is gathered exclusively from a volumetric charge. In the historical test year, the revenue requirement is then the product of a price (P_{t-2}) and a volume (V_{t-2}) and this is set equal to the allowed cost of service

$$P_{t-2} \times V_{t-2} = Cost_{t-2}$$

so that

$$P_{t-2} = Cost_{t-2} / V_{t-2} = Unit\ Cost_{t-2}.$$

The rate equals the cost per kWh of sales, which we may call the *unit* cost of service in the historical test year.

Revenue in the rate year is the product of this same price, which reflects *historical* business conditions, and the *contemporary* sales volume. The ratio of cost to revenue may then be restated as

$$\begin{aligned} Cost_t / Revenue_t &= Cost_t / (P_{t-2} \times V_t) \\ &= Cost_t / [(Cost_{t-2} / V_{t-2}) \times V_t] \\ &= (Cost_t / V_t) / (Cost_{t-2} / V_{t-2}) \\ &= Unit\ Cost_t / Unit\ Cost_{t-2}. \end{aligned} \qquad [A1]$$

An historical test year rate is thus non-compensatory if the utility's unit cost is higher in the rate year than it was two years ago in the test year. Growth in the unit cost of the utility is thus the fundamental reason for earnings attrition. Note also that

$$Unit\ Cost_t / Unit\ Cost_{t-2} = (Cost_t / Cost_{t-2}) / (V_t/V_{t-2}). \qquad [A2]$$

Unit cost thus grows between the test year and the rate year if cost grows more rapidly than the sales volume. Growth in the sales volume therefore matters as well as cost growth in determining a utility's unit cost trend. Moreover, the ability of historical test year rates to avoid under or, for that matter, over earning depends on the stability of the relationship between cost and billing determinants.

The key result that historical test years are non-compensatory when unit cost is rising extends to the real world situation in which a utility provides multiple services, each with several charges. In this situation the ratio of the total delivery volume in [A2] is replaced by a weighted average of the ratios for all billing determinants.[51]

[51] The weight for each individual billing determinant is its share of the total base rate revenue.

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