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:

$$\textit{growth Cost} - \textit{growth Input Prices} \quad \textit{growth Output} \quad \textit{growth Productivity}. \qquad [1]$$

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.

### Unit Cost Drivers

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).* [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

[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

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[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.

Econometric Modeling

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.

Benchmarking

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]

[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

[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

[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)

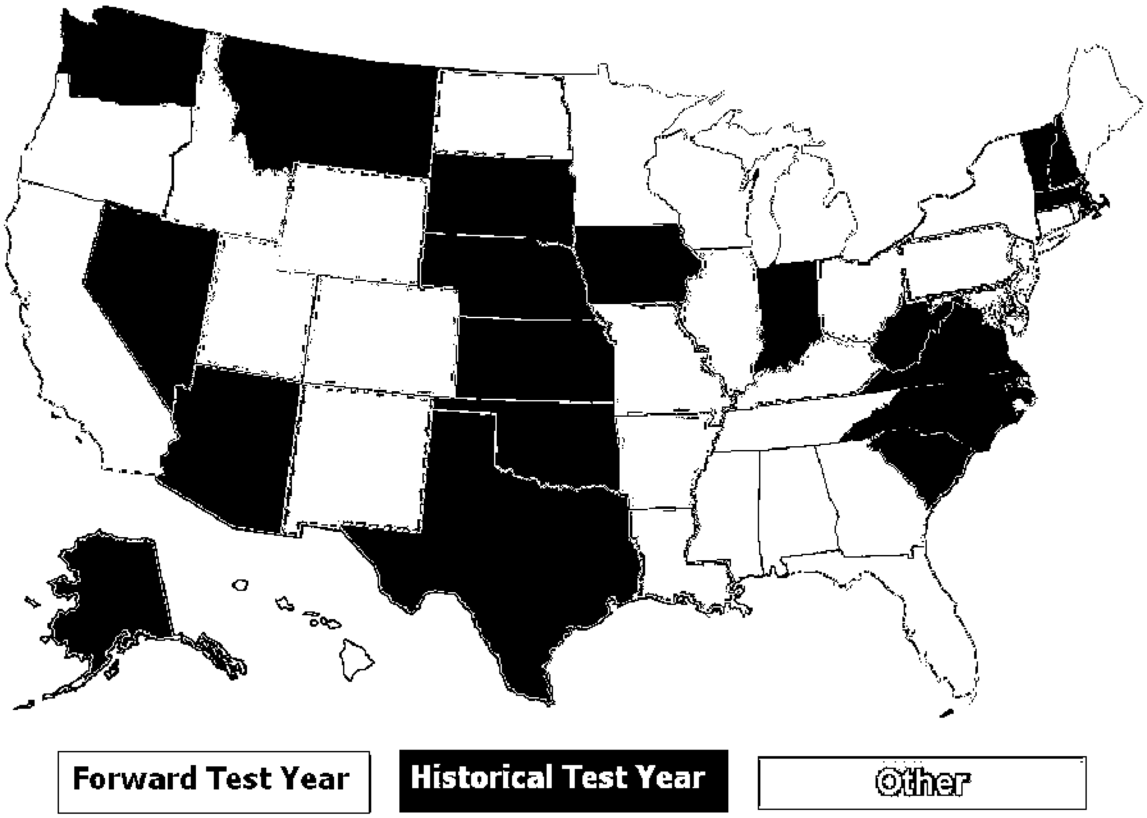
| Utility Name | Notes |
|---|---|
| Colorado | Public Service of Colorado can file FTY evidence. No FTY rates have yet been approved but the most recent case made extraordinary HTY adjustments. |
| District of Columbia | PEPCO has filed rate cases using both hybrid and historical test years recently. |
| 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

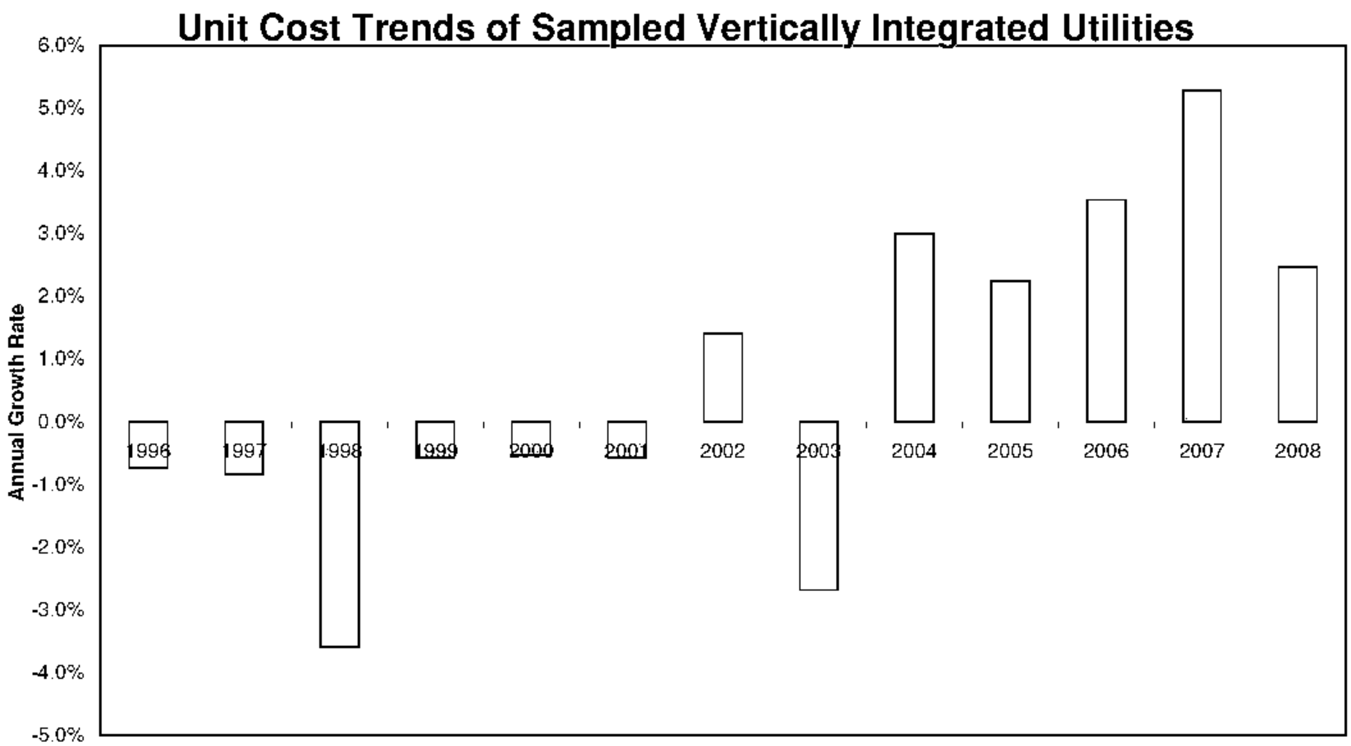
*Sample Average Annual Growth Rates, Unweighted*

| 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

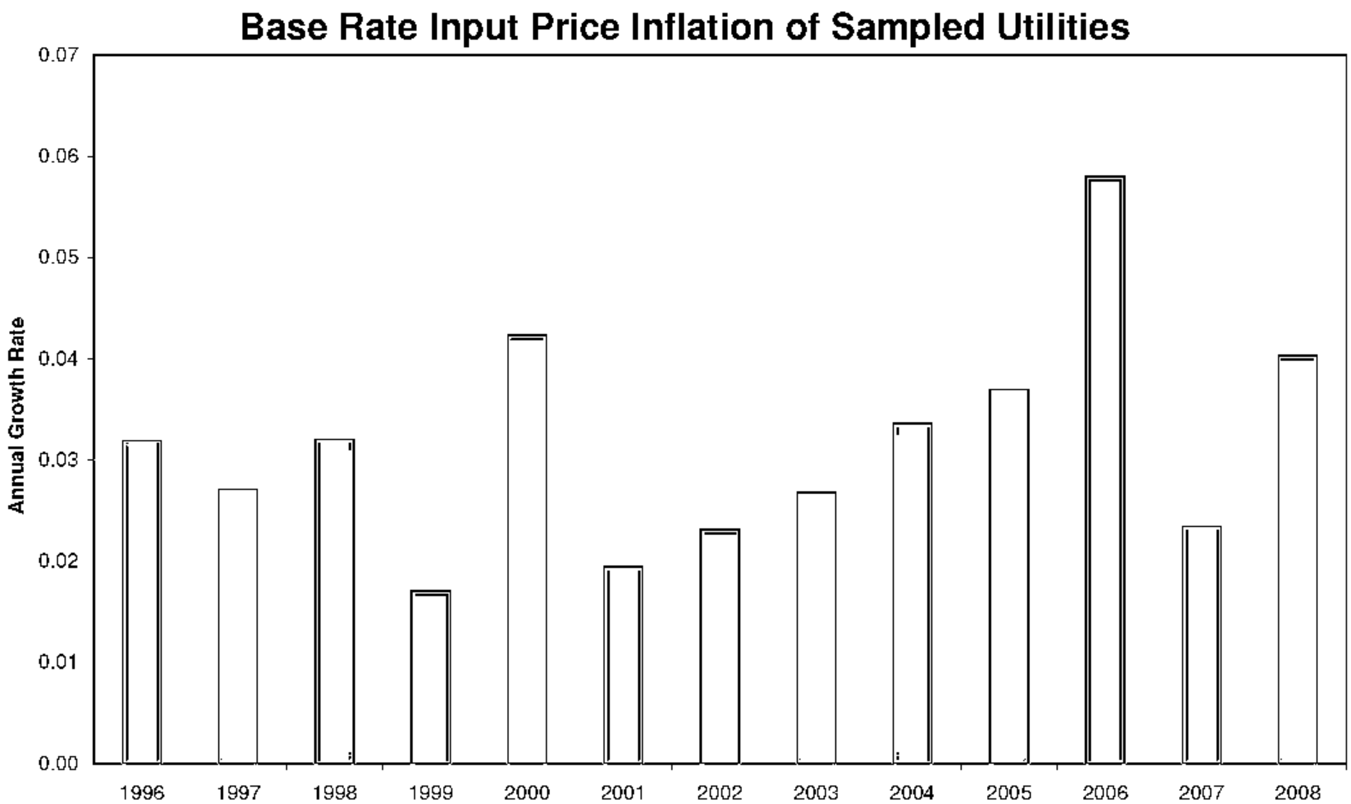
| | **Summary Input Price Index** | | **Labor** | | **Materials & Services** | | **Capital** | |
|---|---|---|---|---|---|---|---|---|
| Year | Index | Growth Rate | Index | Growth Rate | Index | Growth Rate | Index | Growth Rate |
| 1995 | 1.000 | | 1.000 | | 1.000 | | 1.000 | |
| 1996 | 1.032 | 3.2% | 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<br>Handy Whitman electric utility construction cost indexes<br>Average yields on utility bonds calculated from FERC Form 1 data gathered by SNL Interactive<br>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

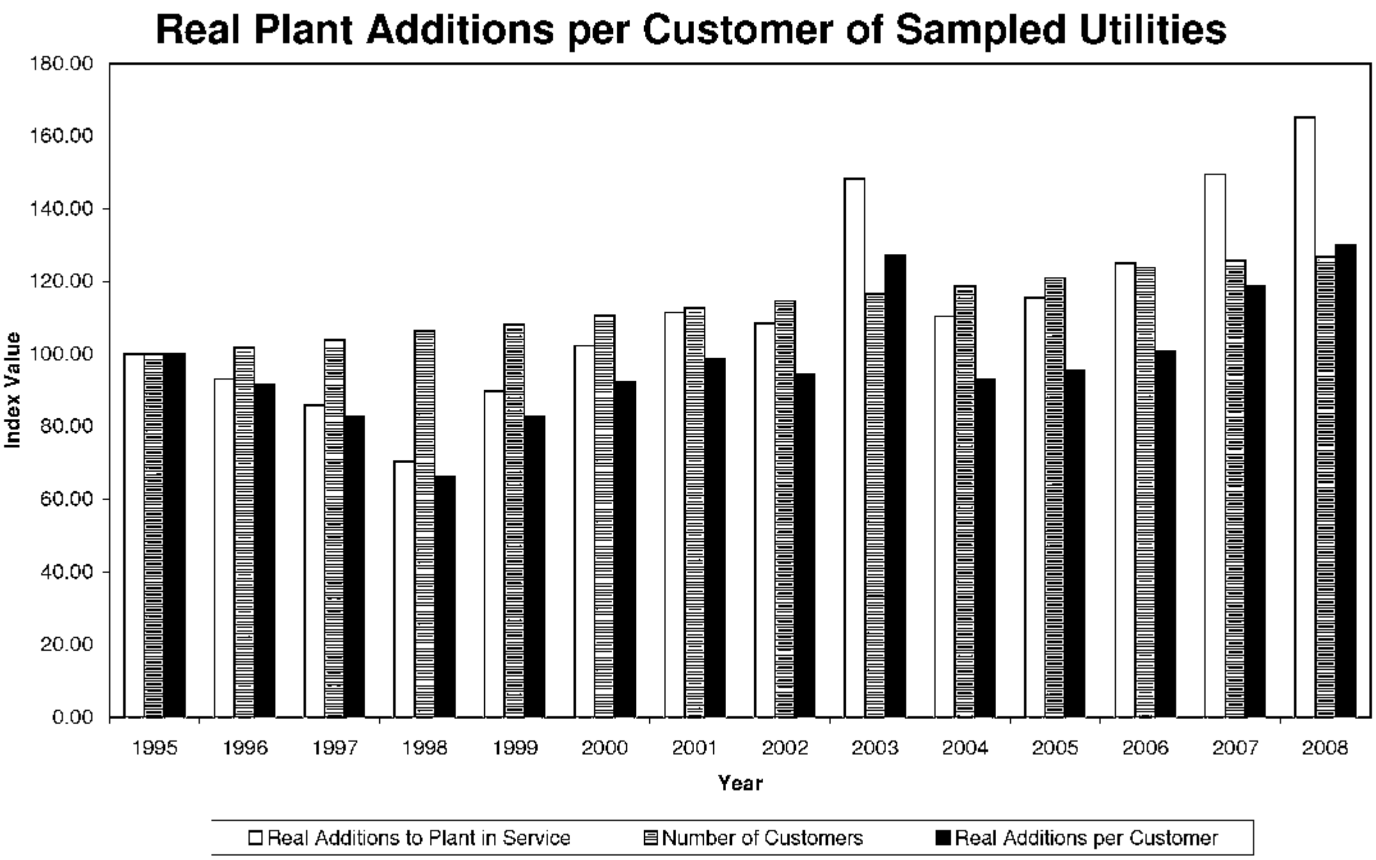

Real Plant Additions per Customer of Sampled Utilities
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Index Value
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Real Additions to Plant in Service
Number of Customers
Real Additions per Customer

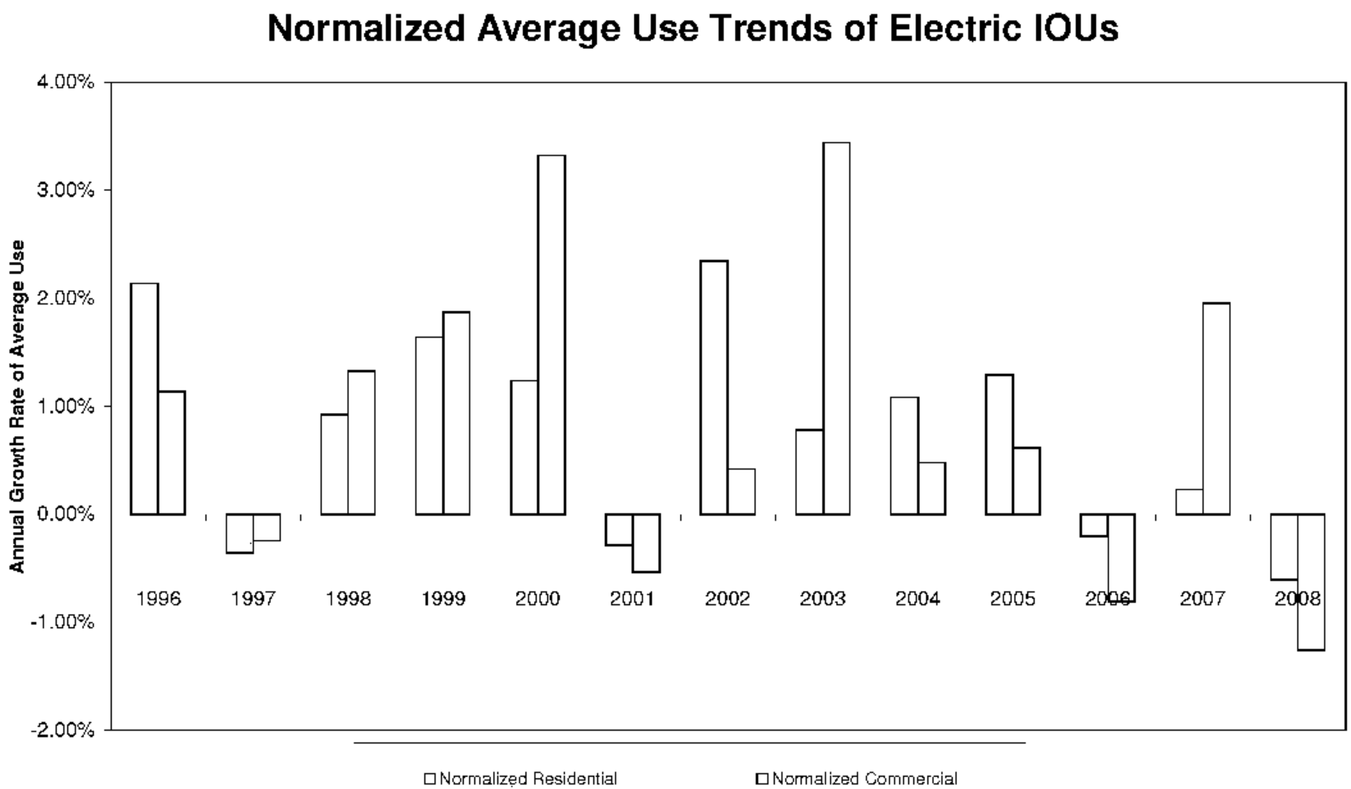
Table 7

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

| Year | Residential | | Commercial | |
|---|---|---|---|---|
| | Raw | Normalized | Raw | 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

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

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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FitchRatings

RATING ACTION COMMENTARY

# Fitch Downgrades CenterPoint Energy Houston Electric to 'BBB+'; Affirms CNP; Outlooks Negative

Wed 19 Feb, 2020 - 4:46 PM ET

Fitch Ratings - New York - 19 Feb 2020: Fitch Rating has downgraded CenterPoint Energy Houston Electric's (CEHE) Long-Term Issuer Default Rating (IDR) to 'BBB+' from 'A-'. The Rating Outlook has been revised to Negative from Stable. In addition, Fitch has affirmed CenterPoint Energy Corp.'s (CNP) Long-Term IDR at 'BBB' and has revised the Rating Outlook to Negative from Stable. A full list of rating actions follows at the end of this release.

Today's rating action follows the approval of CEHE's rate case settlement by the Public Utilities Commission of Texas (PUCT) on Feb. 14, 2020. Fitch believes that the unfavorable outcome signals a more challenging regulatory environment in Texas for CEHE. Lower authorized returns and equity capitalization, combined with tax-reform related refund will pressure CEHE's and CNP's credit metrics in the next few years. Further negative rating action is possible if CEHE's and CNP's FFO adjusted leverage sustains above 5x and 5.2x, respectively. Although the proposed sale of the Infrastructure Services business will facilitate debt reduction and improve CNP's operating risk modestly, Fitch estimates that the transaction has minimal impact on the consolidated FFO adjusted leverage ratio.

## RATING ACTIONS

| ENTITY / DEBT ⬍ | RATING ⬍ | PRIOR ⬍ |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| CenterPoint Energy, Inc. | LT IDR | BBB Rating Outlook Negative | Affirmed | | BBB Rating Outlook Stable |
| | ST IDR | F2 | Affirmed | | F2 |
| senior unsecured | LT | BBB | Affirmed | | BBB |
| junior subordinated | LT | BB+ | Affirmed | | BB+ |
| senior secured | LT | A | Downgrade | | A+ |
| preferred | LT | BB+ | Affirmed | | BB+ |
| senior unsecured | ST | F2 | Affirmed | | F2 |
| senior unsecured | ULT | BBB | Affirmed | | BBB |
| senior secured | ULT | A | Downgrade | | A+ |
| CenterPoint Energy Houston Electric, LLC | LT IDR | BBB+ Rating Outlook Negative | Downgrade | | A- Rating Outlook Stable |

VIEW ADDITIONAL RATING DETAILS

## KEY RATING DRIVERS

Negative Rate Case: On Feb. 14, 2020, the PUCT approved CEHE's rate case settlement, authorizing a $13 million or 0.52% base rate increase. The increase reflects a 9.4% Return on Equity (ROE) and 42.5% equity capitalization, below the existing 10% authorized ROE and 45% equity ratio, and lower than the industry's average authorized ROE. The ROE is the lowest among all transmission and distribution utilities operating in Texas while the equity capitalization is average. CEHE will refund $105 million federal tax reform-related unprotected excess accumulated deferred federal income tax, or UEDIT, over a three-year period. CEHE also agreed to not file for the Distribution Cost Recovery Factor (DCRF) in 2020. New rates will take effect 45 days after the approval of the order.

Credit Metrics: The rate case has material negative impact on CEHE and CNP's credit metrics. Barring any mitigating actions, Fitch estimates that CEHE's FFO adjusted leverage will range in the high 4x to low 5x in the next three years, and that CNP's FFO adjusted leverage will hover around the 5.3x guideline ratio for a downgrade. The leverage ratio has incorporated the expected sale of the Infrastructure Services business.

Regulatory Ring-fencing Enhances Protection: The rate order will impose a set of regulatory ring-fencing measures but does not include certain dividend restrictions. The ring-fencing provisions will further enhance credit separation among CEHE, CNP and affiliates and are complimentary to the existing corporate governance structure. The existing money pool arrangement will remain.

Asset Sale Modestly Improves Business Risk: The proposed sale of the unregulated Infrastructure Services business will mildly improve CNP's credit profile, increasing its utilities earnings to 80% over the next few years from 75%. However, the transaction has minimal impact on the consolidated FFO adjusted leverage ratio, as the earnings loss will largely offset the debt reduction.

Rating Linkages: Generally, absence of guarantees and cross-defaults, and dividend restrictions among other factors render legal ties weak between CEHE and CNP. While operational and strategic ties are strong between them, a prescribed regulatory capital structure for CEHE lead to weak linkage with CNP. Fitch typically restricts the IDR notching differential to two notches.

Fitch applies a bottom-up approach in rating CEHE and CNP. CEHE's ratings reflect their stand-alone credit profile while CNP's ratings reflect a consolidated credit profile. Fitch considers CEHE stronger than CNP, due to its lower operating risks as a fully regulated transmission and distribution company. Conversely, CNP's investment in Enable and other unregulated businesses carry higher risks than the regulated operations. Historically, high level of parent only debt (>25%) have also resulted in weaker credit metrics at CNP. Upon the reduction of equity layer at CEHE and debt paydown at CNP as a result of the sale of the Infrastructure Services business, CNP's parent-level debt is expected to decline.

## DERIVATION SUMMARY

CNP carries higher operating risks than the fully regulated NiSource Inc. (NiSource, BBB/Stable), due to its investment in the Enable Midstream Partners (Enable; BBB-/Stable) and other non-utility businesses. Similar to Sempra Energy (BBB+/Stable), approximately 75% of CNP's earnings (including its share of Enable's distribution) is from regulated utilities. Upon the closing of the sale of the Infrastructure Services business, utilities could represent 80% of the total earnings over the next few years. However, Fitch considers Enable's midstream business riskier than Sempra's Cameron liquefied natural gas project, which is fully contracted and has no commodity risks. CNP's utilities are more geographically diversified and more insulated from the aggressive renewable standards and wildfire risks than Sempra's California utilities. CNP and OGE Energy (BBB+/Stable) are both exposed to the commodity sensitive midstream business through Enable. CNP's utility operations are diversified, whereas OGE's only utility is concentrated in Oklahoma. CNP and OGE both experienced negative regulatory treatment. Absent any offsetting measures after the rate case, CNP's FFO-adjusted leverage is estimated to be in the low to mid-5x in the next two years, weaker than Sempra Energy's 5x and OGE Energy's 3.8x. NiSource's credit metrics were affected by the gas explosions in 2018, but expected to return to normal after receiving insurance proceeds and equity issuances.

Prior to the rate case, CEHE benefited from slightly more favorable regulatory treatment than its peers. CEHE's 2010 rate case authorized a 45% equity ratio, higher than Oncor Electric Delivery Company's (BBB+/Stable) 42.5% and AEP Texas Inc.'s (BBB+/Stable) 40%, and the same as Texas-New Mexico Power Company's (TNMP; not rated) equity ratio. CEHE's existing 10% authorized ROE was higher than AEP Texas' 9.98%, Oncor's 9.8% and TNMP's 9.65%. Going forward, CEHE's 9.4% ROE will lag behind its peers while the 42.5% equity ratio is relatively on par. Fitch estimates that CEHE's FFO adjusted leverage could range from high 4x to low 5x in the next two to three years. Oncor and AEP Texas's FFO adjusted leverage are estimated to be in high 4x for the same period.

## KEY ASSUMPTIONS

- New rates are implemented in April 2019;

- DCRF resumes in 2021;

- Incorporated the sale of Infrastructure Services business and reduce debt at CNP;

- No mitigating actions are assumed.

## RATING SENSITIVITIES

CEHE

Developments That May, Individually or Collectively, Lead to Positive Rating Action

-The Rating Outlook can be revised to Stable if FFO adjusted leverage is below 5x on a sustained basis.

Developments That May, Individually or Collectively, Lead to Negative Rating Action

-FFO-adjusted leverage exceeds 5.0x on a sustained basis;

-Termination of the two trackers TCOS and DCRF;

-Further signs of deterioration of regulatory relationship.

CNP

Developments That May, Individually or Collectively, Lead to Positive Rating Action

-The Rating Outlook can be stabilized if the CNP's FFO adjusted leverage is below 5.3x on a sustained basis;

Developments That May, Individually or Collectively, Lead to Negative Rating Action

-FFO adjusted leverage reaches 5.3x on a sustained basis;

-If CNP and Vectren's utilities' regulatory environment becomes unfavorable to the point that they are unable to receive timely and reasonable recovery in rates;

-Enable requires a meaningful amount of equity support;

-Disproportionate expansion of unregulated businesses resulting in material increase in business risk.

## ESG CONSIDERATIONS

Unless otherwise disclosed in this section, the highest level of Environmental, Social and Governance (ESG) credit relevance is a score of '3', which indicates ESG issues are credit neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

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Corporate Rating Criteria - Effective from 19 February 2019 to 27 March 2020 (pub. 19 Feb 2019)

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Parent and Subsidiary Rating Linkage - Effective from 27 September 2019 to 18 August 2020 (pub. 27 Sep 2019)

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**COMMENTS** — 18 May, 2023 | 20:40 — United States of America, EMEA, Latin America, APAC, APAC, Canada

# The Outlook For North American Regulated Utilities Turns Stable


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Secondary Contacts: **Daniela Fame, Joe Marino**


Sector **Oil & Gas, Oil & Gas, Corporates, Infrastructure & Utilities, Utilities & Power**

Tags **Americas, Latin America, APAC, EMEA**

View Analyst Contact Information

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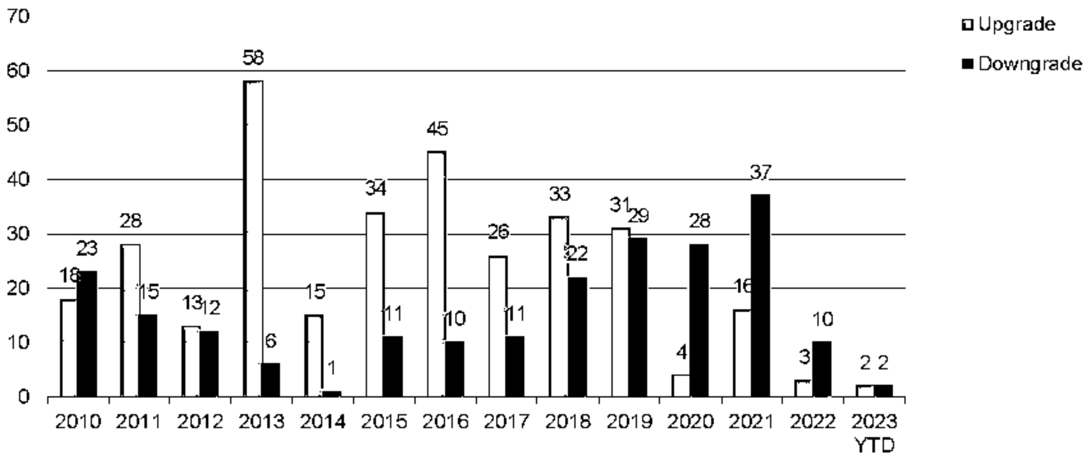
## Key Takeaways

- S&P Global Ratings has revised its outlook for the investor-owned North American regulated utility industry to stable from negative.
- Our reassessment follows three years in which downgrades significantly outpaced upgrades.
- Significant risks for the industry remain, including inflation, record levels of capital spending, and the practice of many companies to operate with minimal financial cushion from their downgrade thresholds.
- We expect future downgrades and upgrades will be more balanced over the next two years.

In early 2020, S&P Global Ratings revised the outlook for the investor-owned North American regulated utility industry to negative from stable. This was the first time in more than a decade that our outlook on the sector was negative. Since 2020, downgrades outpaced upgrades by more than 3:1, weakening the median rating on the sector to 'BBB+' from 'A-', the first time ever that the median rating was in the 'BBB' category. Prior to 2020, the last year that the industry's downgrades outpaced upgrades was in 2010.

Chart 1

**North American regulated utilities upgrade and downgrade comparison**




As of May 15, 2023. Source: S&P Global Ratings.

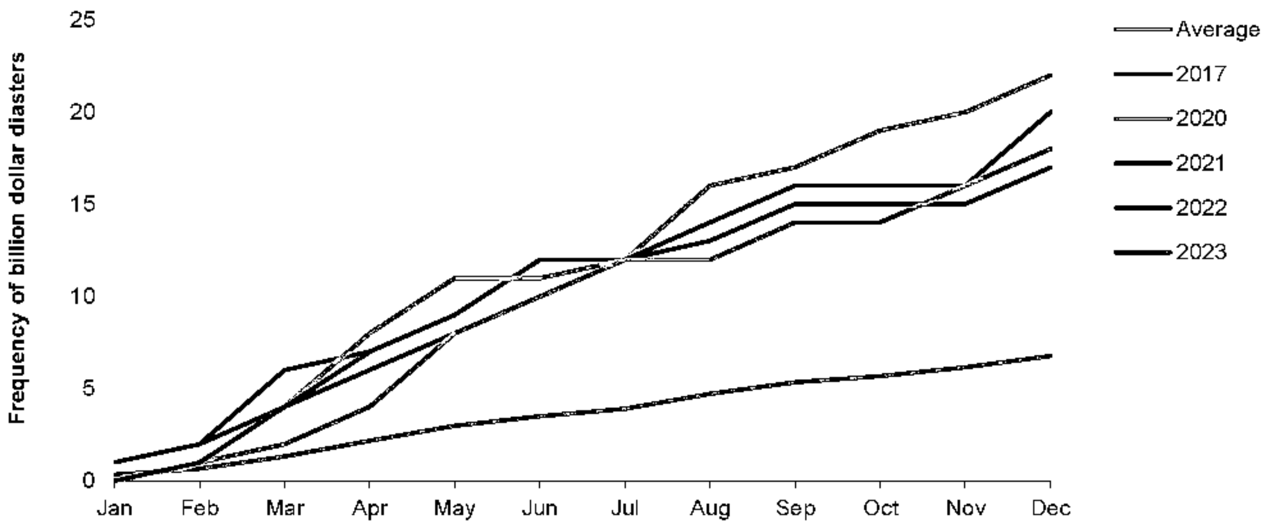


# The Impact Of ESG Factors And High Capital Spending

Credit quality weakened over the past three years primarily as a result of two developments. One is the increasing influence of environmental, social, and governance (ESG) credit factors on our credit analysis, which considers companies' exposures to such factors as climate risks or governance structure. The other is high capital spending and the failure to fund such robust spending in a credit-supportive manner. Physical risks such as exposure to wildfires, storms, extreme temperature events, and hurricanes, remains a considerable risk for the industry. In fact, over the past three years the U.S. experienced its highest level of damages ever from physical risks (chart 2). In response, the industry continues to proactively work with regulators, implementing various credit-supportive tools. These initiatives include increasing storm reserve accounts, self-insurance, securitization, system hardening, and wildfire mitigation programs. While these tools will reduce some of this risk, we expect that because of climate change, the industry will always be somewhat vulnerable to physical risks that could potentially harm credit quality.

Chart 2

**Frequency of U.S. billion dollar weather disasters**



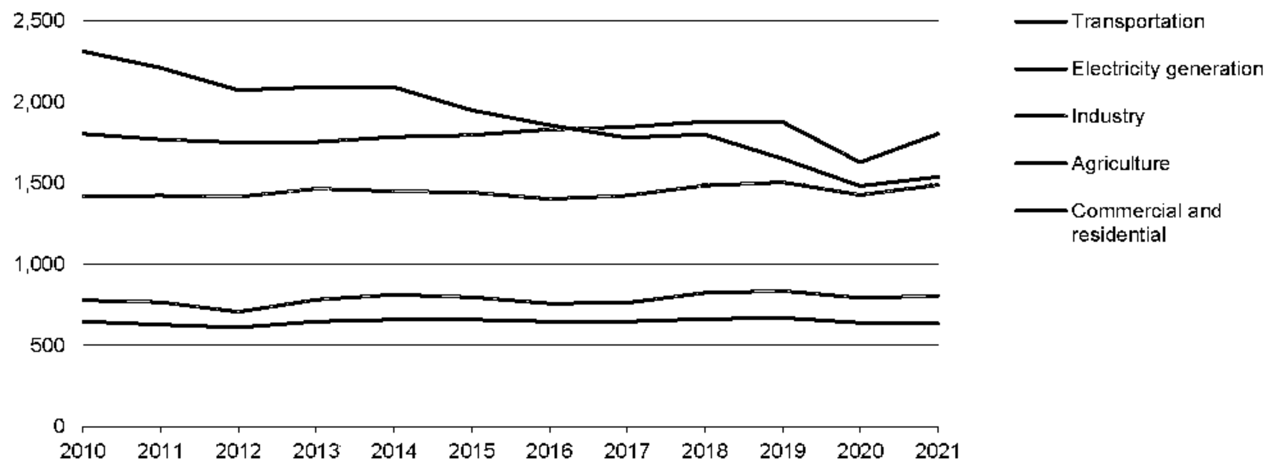

Average is 1980-2023. Source: National Oceanic and Atmospheric Administration.



The industry's disproportionate greenhouse gas (GHG) emissions compared to other industries and governance deficiencies also constrained its credit quality over the past three years. In response, the industry took steps to close coal plants, significantly increase its reliance on renewable energy, and reduce its total GHG emissions. Currently, almost all the companies we rate have tangible net zero emission targets and the industry has already reduced its GHG emissions by over 30% during the past decade, which we view as supportive of credit quality.

Chart 3

**U.S. electric generation shows a significant reduction in GHG emissions**




Source: U.S. Environmental Protection Agency.

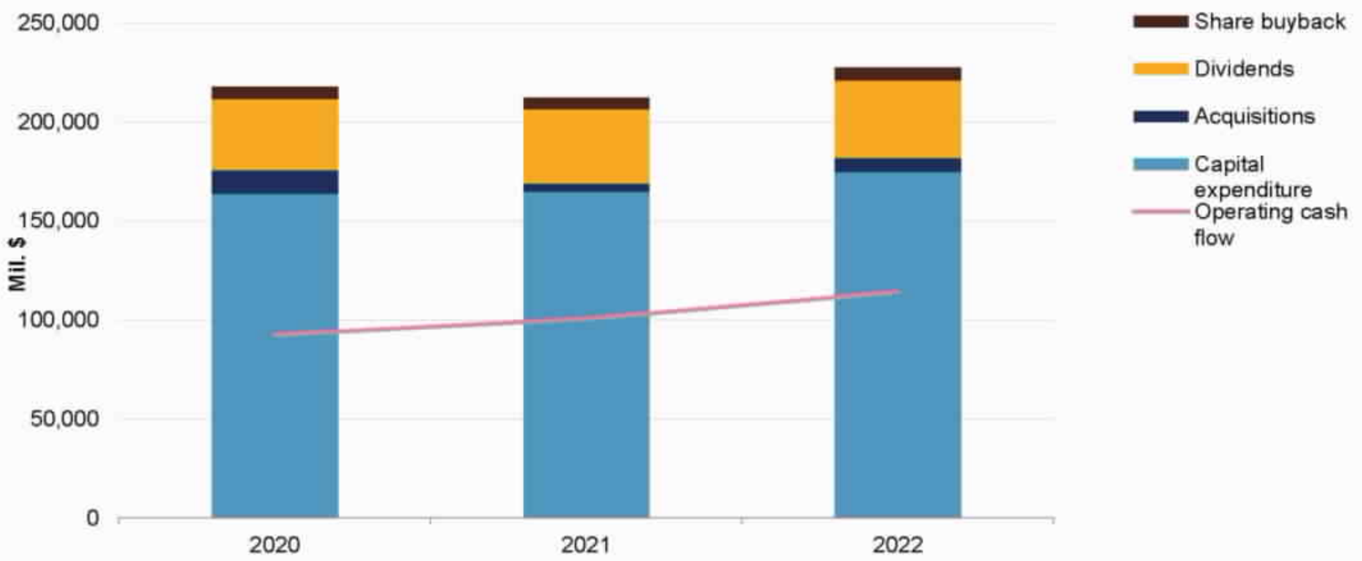


Over the past three years, two large companies experienced material governance deficiencies, including charges of bribery and insufficient internal controls. Since these incidents, other utilities have strengthened their internal controls, reducing the likelihood that another material governance deficiency will be identified within the industry. Overall, we believe that utilities have appropriate internal controls in place and are unlikely to experience similar problems over the next two years.

Investor-owned North America regulated utilities (electric, gas, and water) have increased their spending exponentially over the past two decades at a compounded annual growth rate of about 9%. We expect that the industry's capital spending for 2023 will reach a record at about $200 billion. We expect that utilities will even significantly increase this level of spending over the next two decades, as they step up spending on safety, reliability, energy transition programs, and on initiatives in support of electric vehicles. As a result, the industry's annual negative discretionary cash flow is expected to continue to remain consistently greater than $100 billion. Because utilities have not consistently funded these deficits in a credit-supportive manner, the industry's credit measures and credit quality have weakened.

Chart 4

**North American regulated utilities' reported cash flows and primary uses**




Data represents North American investor-owned electric, gas and water utilities. Source: S&P Global Ratings.



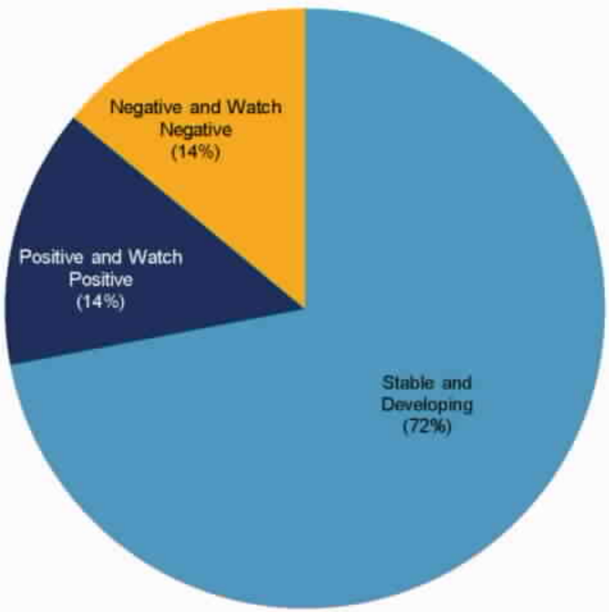
# The Stable Industry Outlook Mirrors Improving Economic Conditions

Our outlook for the industry as a whole reflects the increasing percentage of utilities with a stable outlook, lower natural gas prices, and a slowing of inflation. At year-end 2020, about 35% of the companies we rate in the sector had a negative outlook compared with only about 14% as of May 2023. Furthermore, for the first time in years, the current percentage of utilities with a positive outlook (14%)

is the same percentage of those with a negative outlook. Much of this upside reflects the financial cushion that companies have after a downgrade and the more stringent internal controls they've implemented following the identification of several governance deficiencies.

Chart 5

**North American regulated utilities industry outlook 2023 YTD**

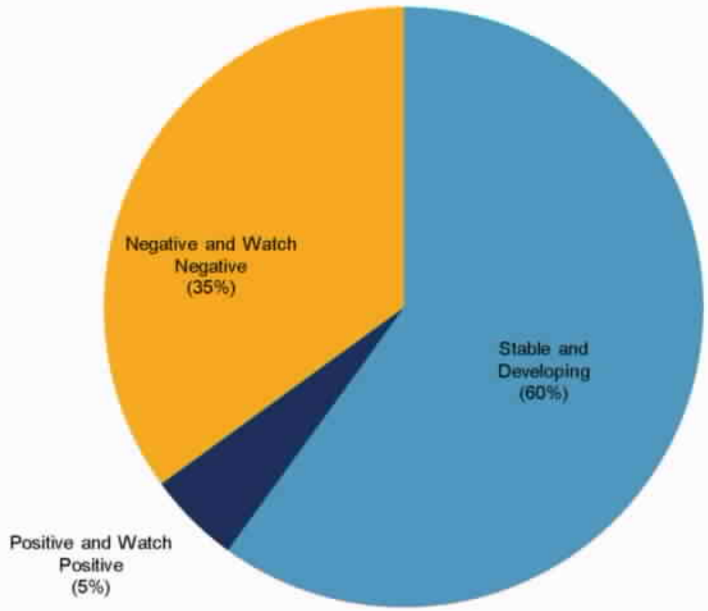



Data as of May 15, 2023. Source: S&P Global Ratings.



Chart 6

North American regulated utilities industry outlook 2020



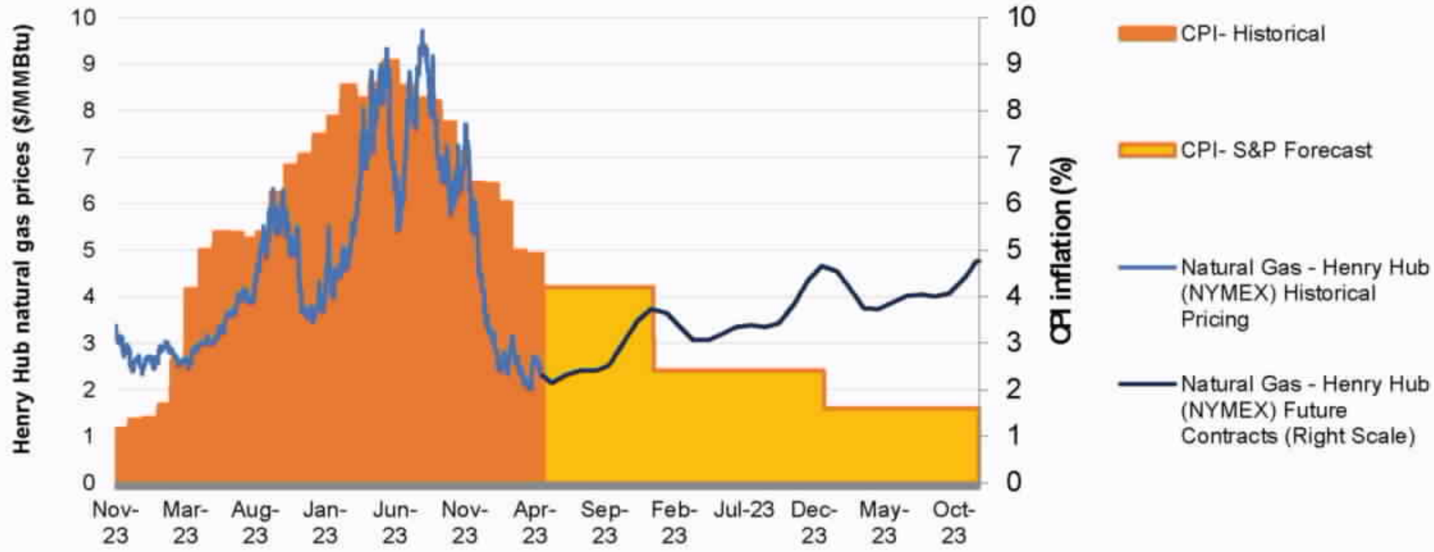

Source: S&P Global Ratings.



More recently, economic indicators have gradually improved. Inflation is increasing at a considerably slower pace with April's consumer price index (CPI) at 4.9% compared 9.1% in June 2022. Additionally, natural gas prices have significantly retreated from August 2022 highs when prices at Henry Hub approximated $9 per MMbtu. These healthier economic developments are consistent with S&P Global economists' forecast of CPI at about 4.7% by year-end 2023. This economic strengthening is also important for the utility industry. When gas prices peaked during 2022, many utilities deferred the recovery of these higher costs and are only now starting to bill ratepayers. The recent drop in natural gas prices provides some customer bill cushion, allowing the utilities to bill customers for the previously deferred higher commodity costs without overwhelming the customer.

Chart 7

**Natural gas prices and inflation**




Source: As of May 1, 2023. CAP IQ; S&P Global Ratings, Economic Outlook U.S. Q2 2023: Still Resilient, Downside Risks Rise.



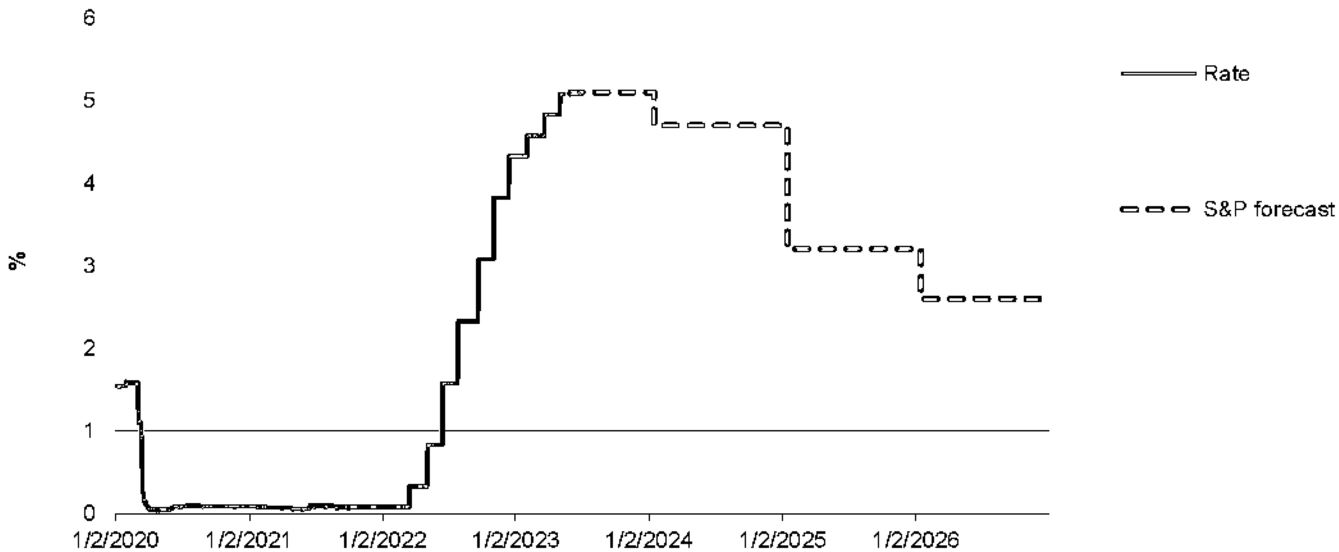
## A More Balanced Upgrade And Downgrade Scenario Going

## Forward

Despite the improvement in economic data, we expect inflation, rising interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. Throughout 2022 and so far in 2023, the Federal Reserve has consistently raised interest rates to reduce the pace of inflation. While these actions appear to have had a positive effect on slowing inflation, there's still been a modest weakening in the industry's financial measures because of inflation and rising interest rates. An environment of continuously rising costs tends to weaken the industry's financial measures because of the timing difference between when the higher costs are incurred and when they are ultimately recovered from ratepayers.

Chart 8

**Federal Reserve funds rate**



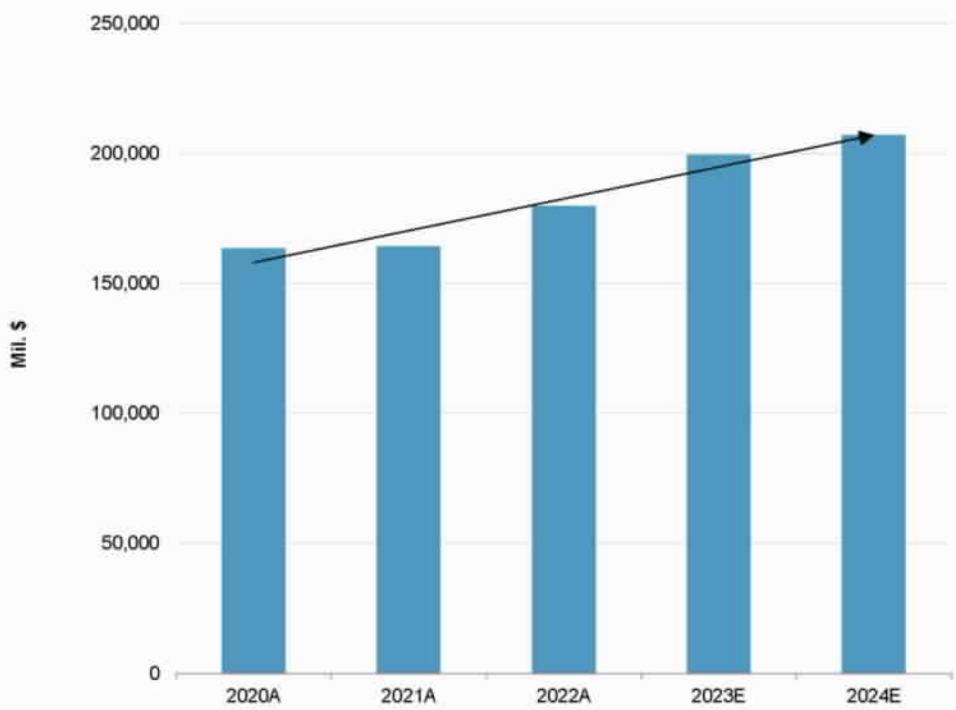

Sources: Federal Reserve Bank of New York; S&P Global Ratings, Economic Outlook U.S. Q2 2023: Still Resilient, Downside Risks Rise.



We expect that utilities' capital spending will continue to gradually rise over the next decade as they allocate funds for safety, reliability, energy transition programs, and to support electric vehicle initiatives. We believe the Inflation Reduction Act (IRA) that provides for long-term tax credits for renewables, batteries, nuclear power, and hydrogen, and allows for the relatively easy transferability of these tax credits, only supports our view that utilities will step up spending over the longer term. Although this growth is vital for utilities to meet their goals, if they don't sufficiently fund it in a credit-supportive manner, their credit measures and credit quality could decline.

Chart 9

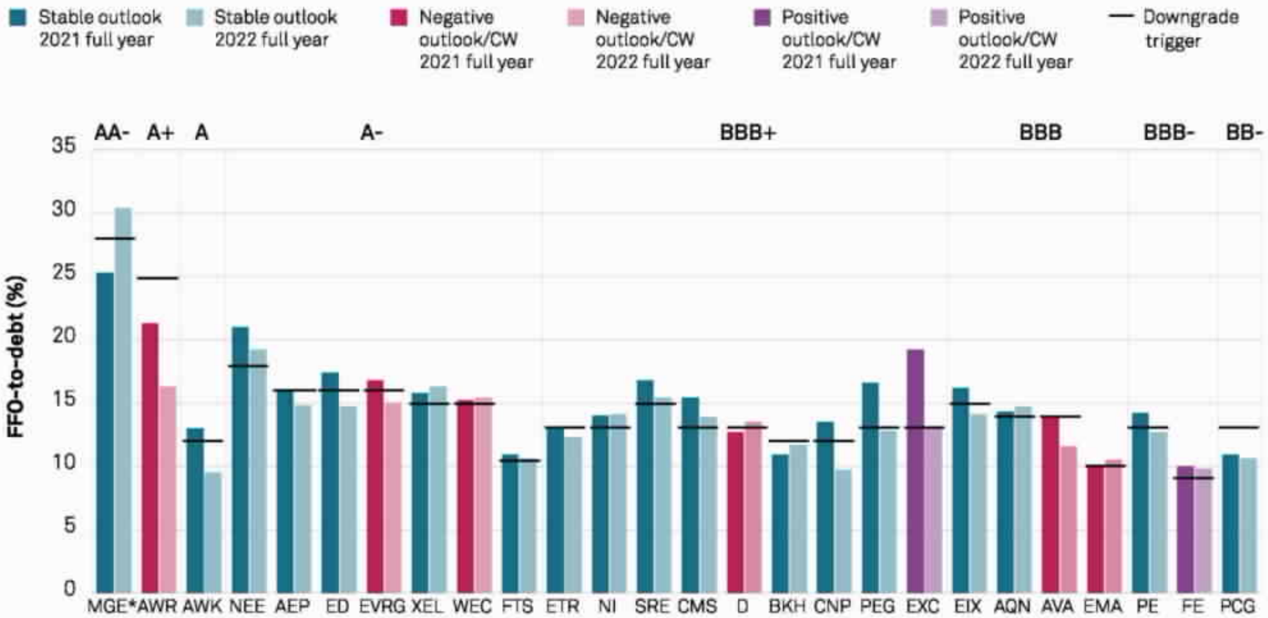
**North American regulated utilities' rising capital expenditures**




Data as of May 1, 2023. a--Actual. e-- Estimates. Source: S&P Global Ratings.


About one-third of the industry is strategically managing their financial performance with only minimal financial cushion, reflecting funds from operations (FFO) to debt that is less than 100 basis points above the downgrade threshold. Because utility cash flows are typically more stable than those of many other industries, this strategy of operating with higher leverage works well under ordinary economic conditions. However, when unexpected risks occur or base-case assumptions deviate from expectations, the utility's credit quality can weaken.

**Minimal financial cushion**




*MGEE (MGE Energy Inc) is parent company of Madison Gas & Electric, this rating relates to Madison Gas & Electric.
As of May 15, 2023. Source: S&P Global Ratings.


Although North American regulated utilities are exposed to these risks, our stable outlook on the industry takes into account improving economic conditions. We expect that over the next two years industry upgrades and downgrades will be more balanced and consistent with the sector's longer-term stable trends.

This report does not constitute a rating action.

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Industry Credit Outlook 2024

S&P Global Ratings

# North America Regulated Utilities

## Credit quality remains pressured

**January 9, 2024**

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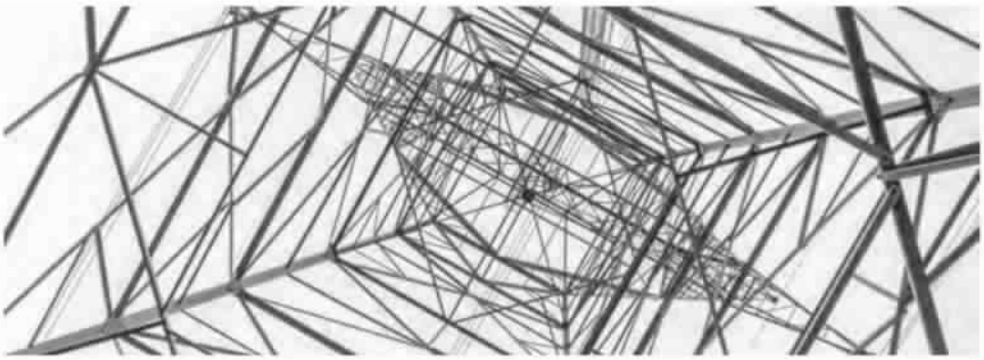

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### What's changed?

**Expansion of wildfire risks** across Western North America.

**Common equity issuance** was significantly below our base case expectations.

**Credit quality erosion.** For the fourth consecutive year, downgrades outpaced upgrades. It is conceivable that 2024 may be the fifth.

### What are the key assumptions for 2024?

**High capital spending** for North America's investor-owned regulated electric, gas, and water utilities.

**Robust dividends** at about $45 billion, reflecting a dividend payout ratio of about 60%.

**Consistent access to the capital markets** is necessary for the industry to fund its debt maturities and cash flow deficits.

### What are the key risks around the baseline?

**Timely recovery** of prudently spent capital and operation and maintenance (O&M) costs is necessary for the industry to maintain credit quality.

**Minimal financial cushion.** About 35% of the industry is operating with limited ability to absorb unexpected events beyond their base case.

**Inflation.** S&P Global's economists expect the consumer price index (CPI) to decrease to below 3% by year-end 2024.

# Ratings Trends: North America Regulated Utilities

Chart 1

## Ratings distribution

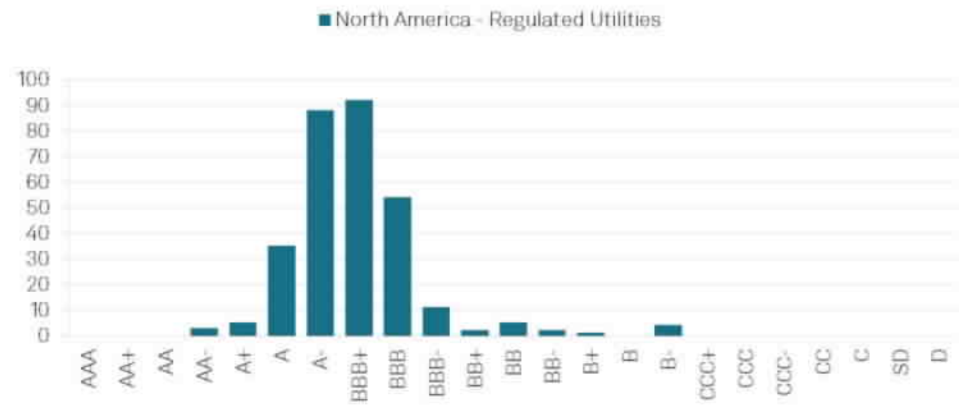



Chart 2

## Ratings outlooks

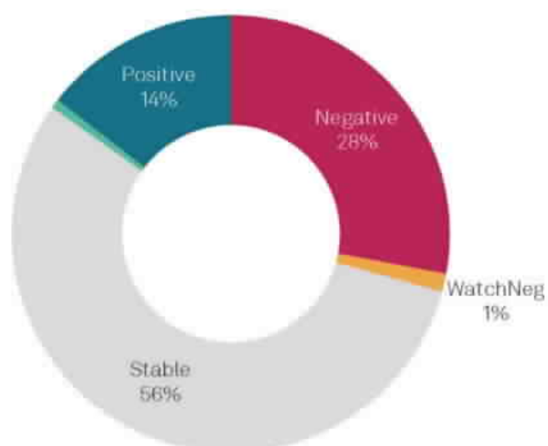
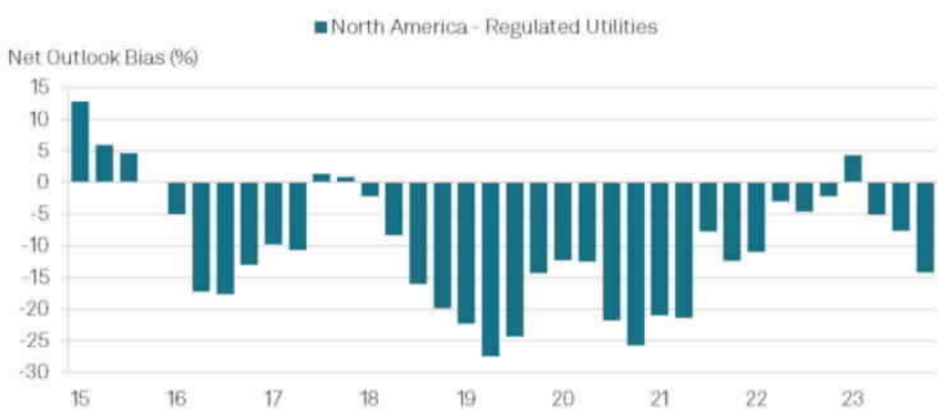



Chart 3

## Ratings outlook net bias




Source: S&P Global Ratings. Ratings data measured at quarter-end.

# Industry Credit Metrics: North America Regulated Utilities

Chart 4

Debt / EBITDA (median, adjusted)

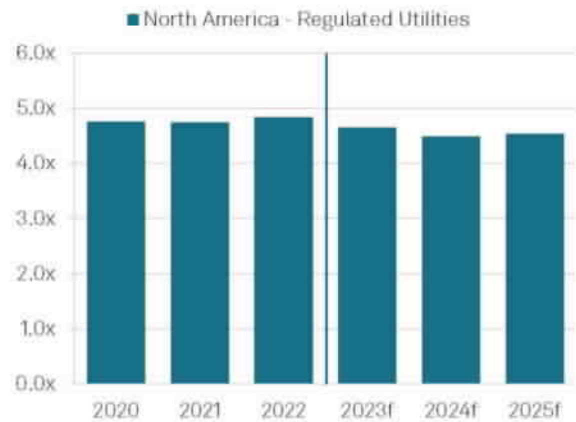



Chart 5

FFO / Debt (median, adjusted)

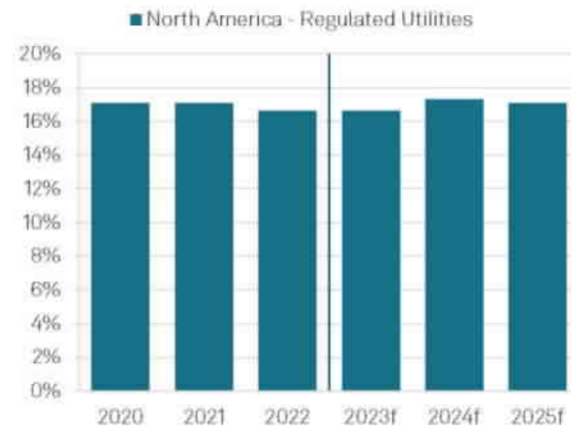



Chart 6

Cash flow and primary uses

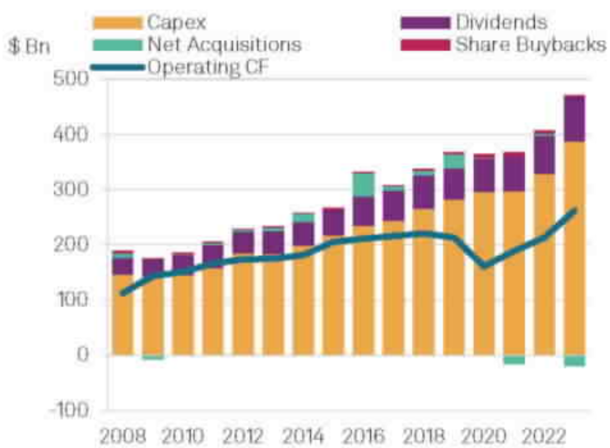



Chart 7

Return on capital employed


Source: S&P Global Ratings, S&P Capital IQ.

Revenue growth shows local currency growth weighted by prior-year common-currency revenue share. All other figures are converted into U.S. dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO—Funds from operations. Most recent (2023) figures for cash flow and primary uses and return on capital employed use the last 12 months' data.

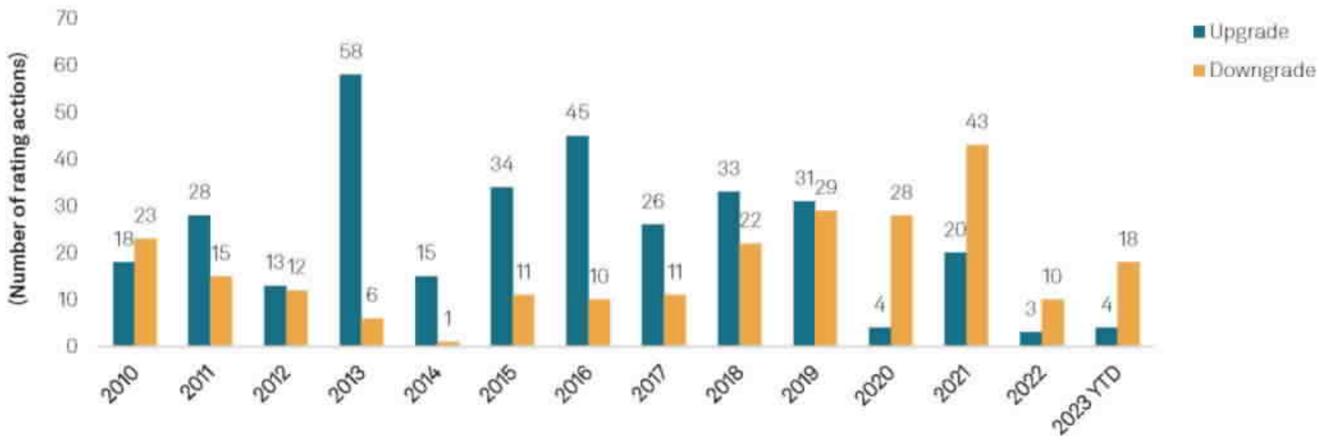
# Industry Outlook

## Ratings trends and outlook

For the fourth consecutive year downgrades significantly outpaced upgrades by more than 3:1 (see chart 8). Most of the 2023 downgrades were directly attributable to rising physical risks and rising leverage because of robust capital spending. We expect 2024 will remain challenging for the industry's credit quality, given the relatively high percentage of negative outlooks.

Chart 8

North America regulated utilities upgrades and downgrades




YTD—Year to date. Data as of Dec. 12, 2023. Source: S&P Global Ratings.

## Main assumptions about 2024 and beyond

### 1. Climate change

Climate change is increasing the frequency of extreme and devastating hurricanes, storms, and wildfires, which is heightening credit risks for North America's investor-owned utilities (IOUs).

### 2. Record capital spending

While the industry's robust capital spending is necessary for prudent investments in safety, reliability, and energy transition, it is directly leading to high cash flow deficits. If these deficits are not funded with debt and equity in a balanced manner, credit quality will likely weaken.

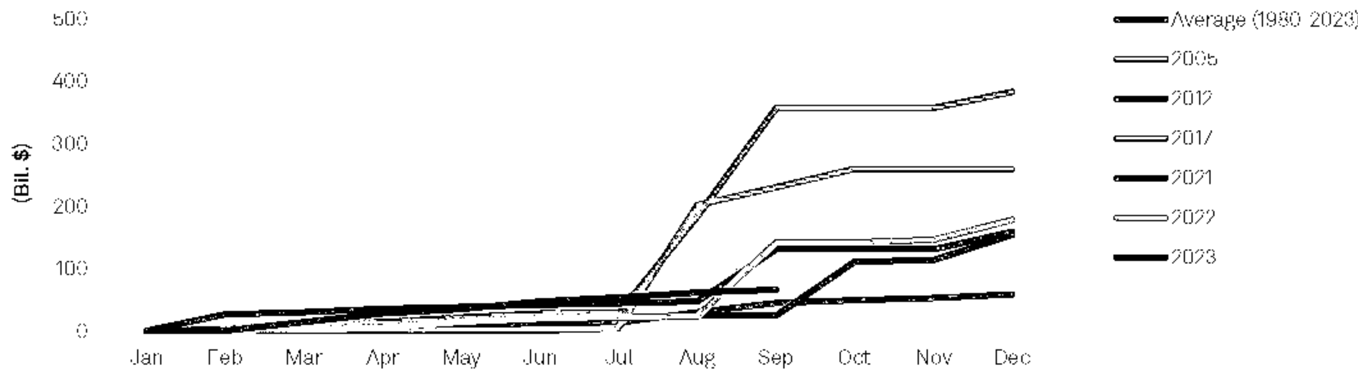
### 3. Management of regulatory risk

Given the significant capital spending, effective management of regulatory risk is important for the industry's credit quality. This includes constructive rate case orders, minimizing regulatory lag, earning its authorized return on equity, and managing the customer bill impact.

**Utilities' exposure to physical risks is increasing.** According to the National Oceanic and Atmospheric Administration (NOAA), on an inflation-adjusted basis, 2021 and 2022 represent two of the top five most destructive years for extreme weather events since 1980 (see chart 9). Our base case assumes these trends will persist, magnifying physical risks for the utility industry.

Chart 9

U.S. billion dollar weather disaster year-to-date event cost (CPI-adjusted)




Source: National Oceanic and Atmospheric Administration.

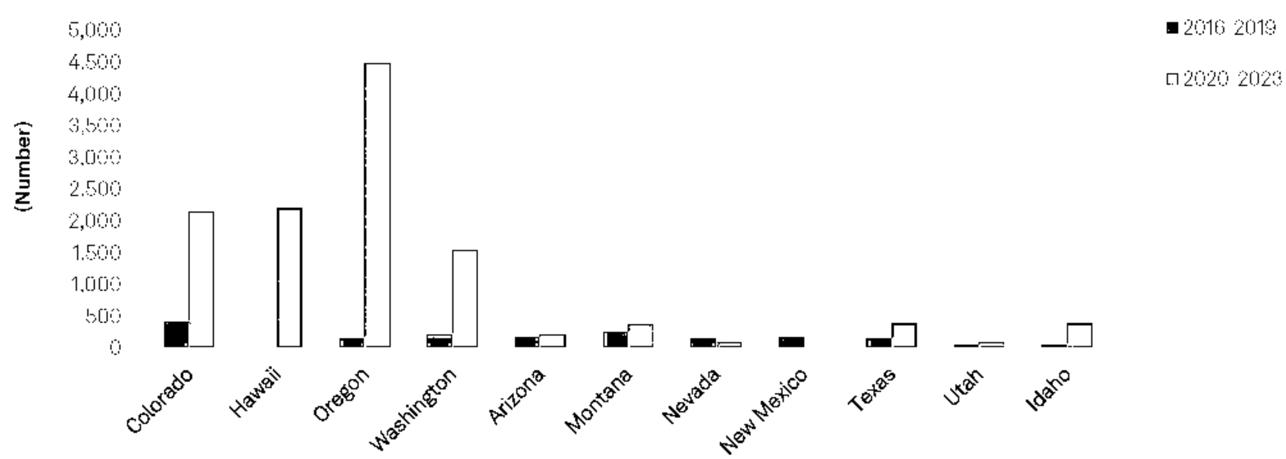
Warmer temperatures increase the humidity, leading to stronger winds and more-devastating tropical storms and hurricanes. Also, drier and hotter weather is a primary cause for more-severe wildfires--as temperatures rise, the vegetation dries up and the landscape becomes more combustible. When high winds are added, the probability of a catastrophic wildfire significantly escalates. As such, areas designated as high-fire-risk have grown across the U.S. This is already taking a toll on credit ratings.

For example, during 2023 we lowered the ratings on Hawaiian Electric Industries Inc. by multiple notches after the most destructive wildfire in Hawaii's history, with nearly 100 fatalities and about 2,200 structures damaged or destroyed. Also during 2023, an Oregon jury awarded 17 plaintiffs in a 2020 wildfire-related class action lawsuit against PacifiCorp about $5.3 million per plaintiff, which was materially above our base case of about $1 million per structure. The jury also found that a broader absent class affected by the fires could bring claims against the company. Accordingly, we downgraded PacifiCorp by two notches and revised the outlook to negative.

Furthermore, since 2020 the number of structures destroyed by wildfires in Colorado, Hawaii, Idaho, Oregon, Washington, and Texas increased by more than 100% compared to the 2016-2019 period (see chart 10). Meanwhile, Arizona, Montana, and Utah have each experienced increases of at least 20% over the same timeframe.

Chart 10

Structures destroyed by wildfires




Source: Headwaters Economics and National Fire and Aviation Management FAMWEB.

**Wildfire mitigation plans.** In light of these trends, we expect IOUs--especially those in the western U.S.--will develop detailed wildfire mitigation plans that reduce damages, minimize litigation risk, and expand capabilities for cost recovery. While it may take considerable time and investments for the industry to fully implement these strategies, the solutions are largely predicated on already-developed and in-use technologies.

System hardening is one investment that improves resiliency, reducing damages and risk. Because our modern economy is so dependent on electricity, system hardening also allows for the faster restoration of operations, decreasing total economic impacts. While system hardening is often expensive and can take many years to fully implement, its long-term benefits typically outweigh its shorter-term costs. Examples include undergrounding powerlines, adding cover conductors--which is the insulation of bare electrical wires with durable long-lived materials that reduce the probability of an electrical fault or spark--and replacing wood poles with steel and concrete.

To reduce the likelihood of a catastrophic wildfire, many utilities have incorporated weather stations that collect data to forecast weather conditions, including high-wind events. Some have incorporated artificial intelligence (AI) and machine learning into their data analysis, high-definition (HD) cameras, satellite and aerial imaging, remote sensing, and drones to enhance their forecasting capabilities. Utilities have also improved communication with state agencies and fire departments, coordinating specific locations that have either encountered or could be highly susceptible to a wildfire.

Critical to reducing wildfire risks is the implementation of a public safety power shutoffs (PSPS) program. PSPS is the proactive de-energizing of power lines in extreme weather conditions, especially in high-wind events. The decision to de-energize is extraordinarily challenging because it could have serious health and safety ramifications for some customers. Accordingly, an effective PSPS program establishes a consistent protocol when drastic measures are required that is approved by regulators and adequately communicated well in advance of the event. We view a PSPS program that establishes such a formal process as credit-supportive for IOUs.

Another crucial component of wildfire prevention is vegetation management, which is the removing or modifying of live and dead vegetation to reduce the potential ignition and spread of wildfire. This ongoing maintenance is essential for reducing the likelihood of debris coming in contact with powerlines, causing a spark that could lead to a wildfire. To further reduce wildfire risks, utilities have implemented enhanced power safety setting systems (EPSS) that automatically shut off power within a tenth of a second if they detect a potential ignition source. Such systems include downed conductor detection, early fault detection, open phase detection, and partial voltage force-out.

Because of the different service territories and topographies, we don't expect the strategies implemented by utilities will be uniform. As such, we expect utility wildfire mitigation plans will be customized but with the consistent goal of reducing risk.

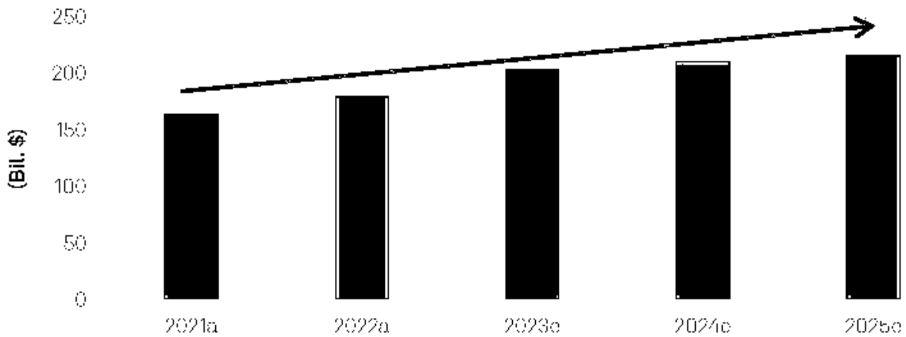
**Litigation risk.** Because utilities operate under potentially hazardous conditions that include safety as well as environmental risks, they have always been susceptible to litigation. However, in recent years, as the climate changes and wildfires increase, litigation and class action civil lawsuits against utilities have intensified. Currently, plaintiffs have filed civil lawsuits against nine utilities because of wildfires. Additionally, an increasing number of class action lawsuits have been filed against water utilities regarding PFAS (per-and poly-fluoroalkyl) contamination. Should the industry's litigation risk continue to increase, credit quality would likely suffer.

**Securitization.** More recently, utilities have increased their use of securitization, which we assess as supportive of credit quality. Securitization allows for the issuance of debt secured by a non-bypassable charge to the customer's bill, allowing the utility to fully recover its costs at a lower interest rate for customers. Because the debt is secured by the high likelihood of customers paying their bills, the associated interest costs are typically lower. We often deconsolidate such debt, resulting in stronger IOU credit measures.

**Record capital spending.** The industry's capital spending on safety, reliability, and energy transition continues to grow at record levels. We expect the 2023 capital spending for North America's electric, gas, and water utilities to approximate $205 billion and rise to about $210 billion and $215 billion in 2024 and 2025, respectively (see chart 11). Under our base case, we expect that the industry's capital spending will continue to grow for at least the next decade.

Chart 11

North America regulated utilities' rising capital expenditures



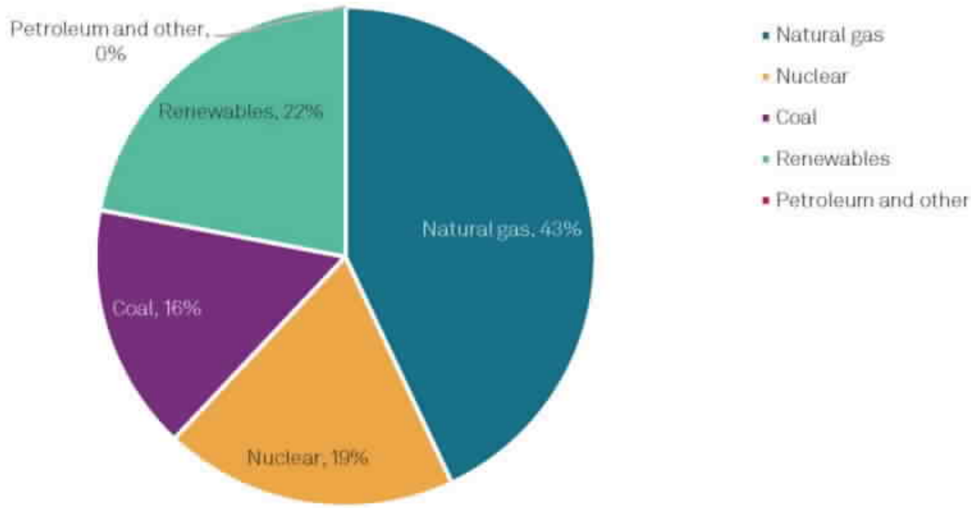

a--Actual. e--Estimate. Data as of Nov. 8, 2023. Capital expenditures represent North American investor-owned electric, gas, and water utilities. Source: S&P Global Ratings.

**Energy transition.** The industry's reliance on coal generation has decreased by about 60% over the past decade, and we expect the vast majority of North America's IOUs will close their remining coal generation by 2035. This transition will reduce the industry's environmental risks but also requires a thoughtful multi-decade strategy to expand renewable energy and battery storage, while simultaneously aligning depreciation and the retirement of coal generation to avoid stranded assets.

**Renewable energy will eventually account for more than 50% of the industry's generation portfolio.** While renewable energy only accounts for about 25% of the industry's electric generation portfolio, over the next decade renewable energy will likely double (see chart 12). The industry's funding of renewable energy will benefit from the Inflation Reduction Act (IRA), which includes significant tax incentives for renewable energy and permits for the transferability of such credits. Transferability allows tax credits that cannot be used on a company's own consolidated tax return because it has insufficient income to be transferred to a third-party. We expect the IOUs will be among the primary beneficiaries of these tax credits. Ultimately, we expect utility regulators will mandate that transferred tax credits are refunded back to customers, and as such we expect the growth of renewable energy will likely be less impactful on the customer bill.

Chart 12

2023 U.S. generation (through August)




Data as of Dec. 12, 2023. Source: U.S. Energy Information Administration.

**Inflation.** Although the rate of inflation has slowed from 2022 levels, it remains elevated relative to historical levels. We anticipate this will result in higher O&M costs that could weaken financial performance. While some utilities have interim mechanisms that reduce the regulatory lag, most will have to file rate cases on a more frequent basis should inflation remain high over the longer term.

Because of rising costs and higher capital spending, rate case filings have significantly increased. In 2019 and 2020, U.S. annual rate case filings averaged about $6 billion but have since increased by 2.5x to an annual average of about $16 billion. This elevates the industry's reliance on managing regulatory risks. Additionally, because about 35% of the industry is managing with only minimal financial cushion--reflecting funds from operations (FFO) to debt that is less than 100 basis points above the downgrade threshold--the ability to absorb unexpected events beyond their base case is limited. Accordingly, should rate case filings be delayed or rate case orders be less than constructive, financial performance and credit quality could weaken.

**Effective management of regulatory risk.** We assess all of North America's regulatory jurisdictions as credit supportive or better, reflecting the industry's generally stable and predictable cash flows (see chart 13). Over the past decade, most of the industry has implemented some combination of decoupling, formula rate plans, forward test years, multiyear rate cases, interim rates, and regulatory riders to significantly improve cash flow stability while minimizing regulatory lag, which is the timing difference between when a utility incurs costs and when it's recovered from ratepayers. Our view of the industry's regulatory constructs supports the industry's mostly investment-grade ratings despite the industry continuing to operate with material cash flow deficits.

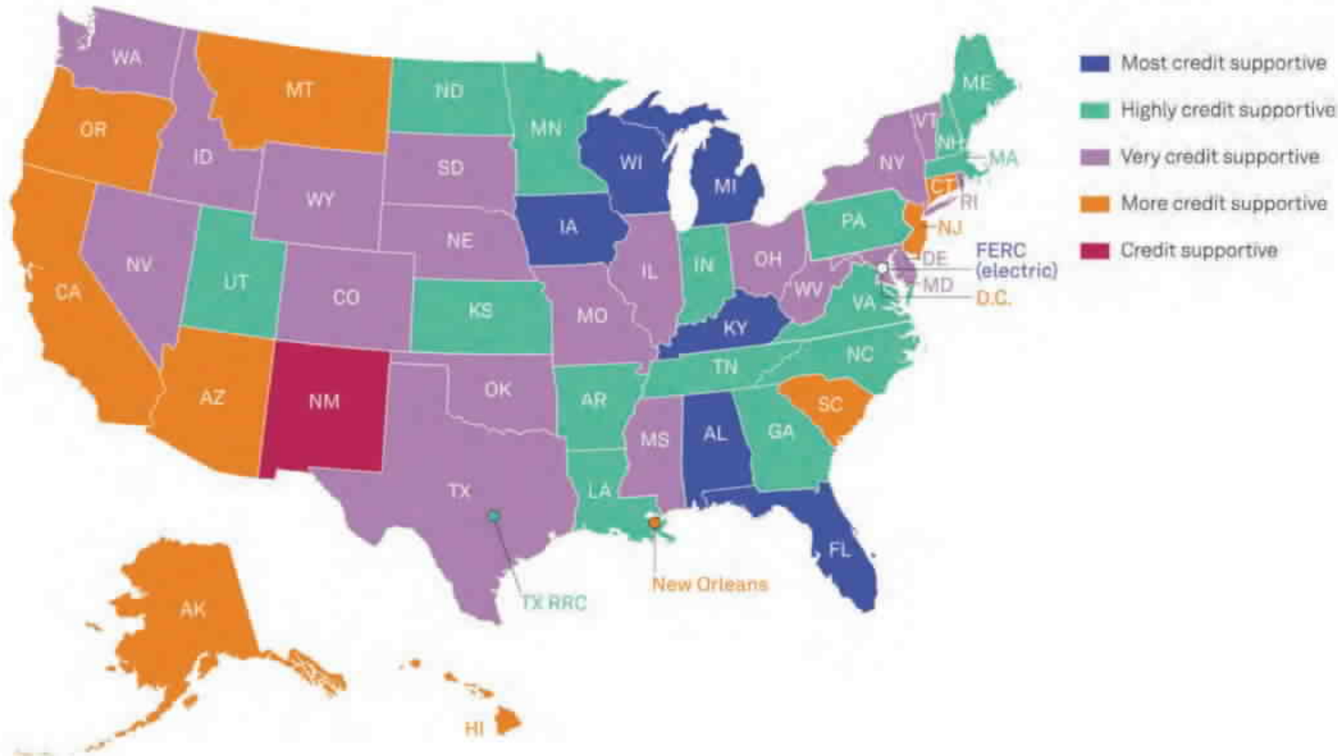
To manage regulatory risk, the industry must maintain the affordability of the customer bill. While the average U.S. electric bill accounts for less than 2.5% of the median U.S. household income, the 2022 average electric bill increased by about 13% primarily because of rising commodity prices. In 2022, the average monthly price for natural gas was $6.40/MMbtu, or nearly double the average price for the prior 13 years. Subsequently, prices have retreated to about $2-$4/MMbtu. Had commodity prices remained high, we believe it would have weakened the industry's ability to manage regulatory risk, pressuring credit quality.

In 2023, several utilities experienced negative regulatory developments that could be indicative of longer-term risks. For example, earlier in 2023 we revised the outlooks on most of Ontario's local distribution companies (LDC) regulated by the Ontario Energy Board to negative, primarily reflecting the increasing regulatory lag associated with transmission costs and wholesale market rates. The lag affected the LDC's earned return on equity and financial performance.

Chart 13

### Regulatory assessment by state

As of November 2023




Source: S&P Global Ratings.


More recently, we revised the outlooks on most of Connecticut's utilities to negative, reflecting the possibility of less cash flow predictability. In June 2023, Senate Bill 7 was signed into law, which gave Connecticut's Public Utilities Regulatory Authority (PURA) greater latitude in determining whether companies over-earn, prohibits PURA from reauthorizing the electric system improvements charge, and allows PURA's discretion over the use of decoupling. We believe this law decreases utilities' cash flow predictability and increases regulatory lag. Additionally, recent 2023 PURA rate orders for Aquarion Co. and The United Illuminating Co. (UI) significantly deviated from our base case expectations, increasing regulatory lag for these utilities. These rate orders did not approve the multiyear rate plans filed, and included material disallowances, penalties for UI, and below-average returns on equity. Should these risks persist, it could result in an increase of regulatory lag and a weakening of utility cash flow predictability for all of Connecticut's regulated utilities, which would be negative for credit quality.

## Credit metrics and financial policy

Despite our expectations that the industry's 2024 capital spending will increase to about $210 billion, we expect generally consistent financial measures, reflecting FFO to debt of about 15%. Our base case is predicated on the industry funding its approximate $85 billion of cash flow deficits with about $40 billion in asset sales and equity issuance. For 2023 the industry's actual equity issuance was considerably below our expectations, resulting in weakening of financial performance. Should this trend persist in 2024, it would likely pressure credit quality.

## Key risks or opportunities around the baseline

**1. Interest rates stabilize.**

Since 2022, rising interest rates have increased costs for North America's IOUs, weakening financial performance and credit quality. Our economists expect federal funds rate will peak in 2023 and then modestly decrease in 2024. Accordingly, we generally expect that as interest rates stabilize it will put less pressure on IOU's financial performance and credit metrics.

**2. Sales growth will return.**

Electricity sales growth stagnation has challenged the North America investor-owned electric regulated utility industry's ability to manage regulatory risk and credit quality. Over the next three years we expect sales growth trends to improve.

**3. Complex projects increase risk.**

During 2023, several offshore wind projects were delayed or canceled because of rising costs for these more challenging projects. To maintain credit quality, we generally expect the industry will focus on lower-risk and smaller projects.

**Interest rates.** IOUs have considerable near-term debt maturities that must be refinanced, and rising discretionary cash flow deficits that are mostly fund with debt. Because of regulatory lag, rising interest rates weakens financial performance. S&P Global economists expect the federal funds rate will peak in 2023 at about 5.5% and then modestly decrease to about 5.3% in 2024. Accordingly, as interest rates stabilize it will put less pressure on the industry's financial performance.

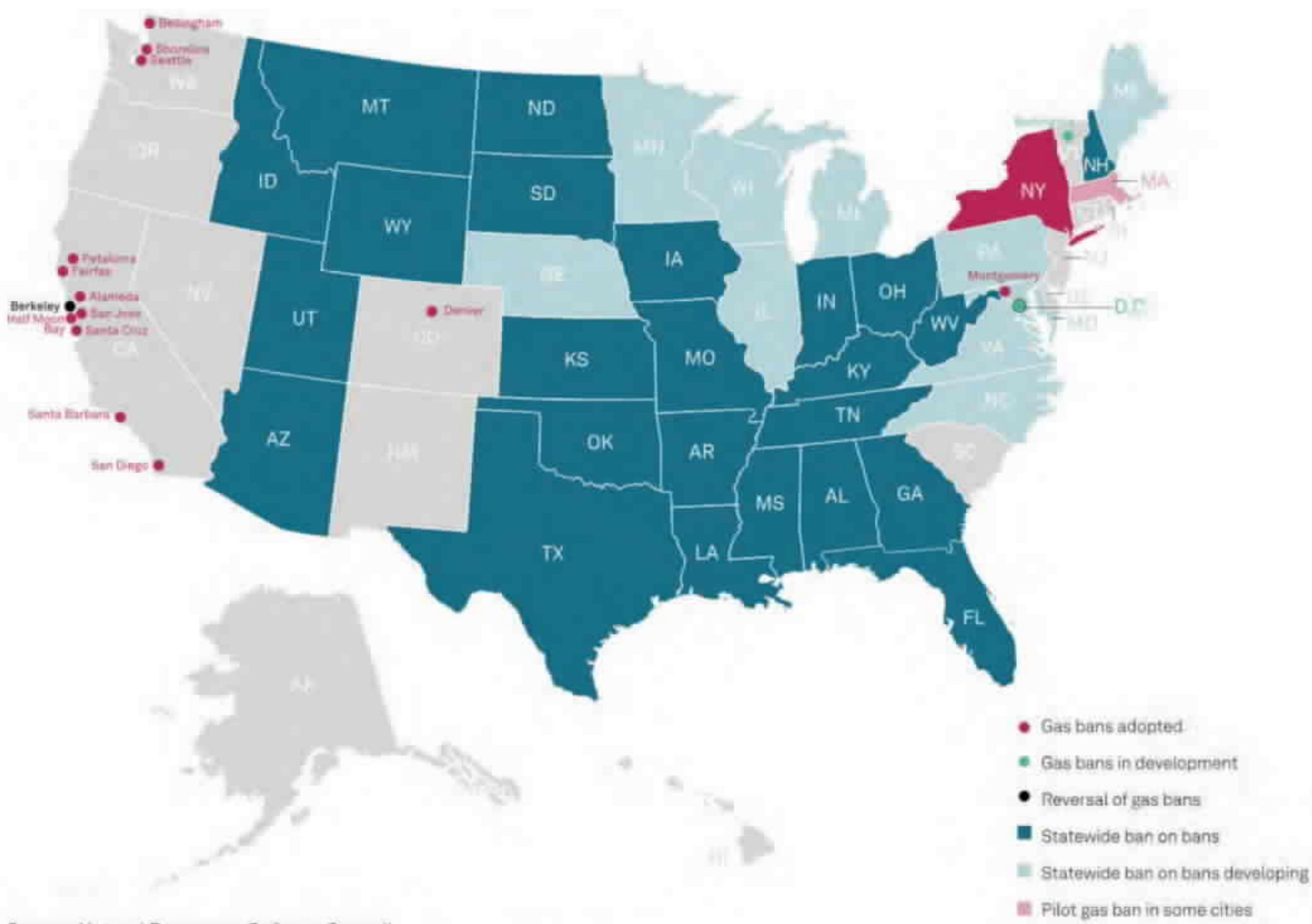
**Spreads narrowing.** Despite the 10-year treasury increasing by about 300 basis points over the last three years to about 4.5% from about 1.5% at year-end 2020, the average authorized return on equity has essentially remained flat at about 9.5% over this same timeframe. The narrowing of this spread directly affects the industry's financial performance. Most IOUs employ double leverage, issuing significant debt at both the holding company level and at the operating utility. The industry is reliant on cash flows from its operating utilities to service its debts at the holding company. As these spreads narrow, financial performance weakens, pressuring credit quality.

**Sales growth.** Electricity sales growth has been flat to negative over the past decade because of conservation, challenging North America's IOU's credit quality. Sales growth increases revenues, EBITDA, and FFO without necessitating a rate increase. This enhances the industry's capacity to maintain its financial measures without depending on a regulator's consistently constructive rate case order. We expect sales to grow in the short term, driven by the onshoring of manufacturing and data centers, and over the medium-term because of increased electrification and electric vehicles. Overall, we view this development as supportive of the industry's credit quality.

**Full electrification.** We expect the longer-term credit quality for some natural gas local distribution companies (LDC) will become increasingly challenging, especially for utilities that operate in warmer climates or whose cities/states have banned new gas connections, severely limiting the growth of the natural gas LDCs. While most of the city bans have occurred in the Western U.S. states, in 2023 New York State banned natural gas and other fossil fuels in most new buildings (see chart 14). Offsetting some of this risk is that a near-majority of states have imposed a ban on the ban of new gas connections. Furthermore, gas LDCs are attempting to reduce their environmental risks by decreasing their carbon footprint through investing in renewable natural gas, blending hydrogen, and initiating various hydrogen infrastructure projects.

Chart 14

### Ban on new gas connections




Source: Natural Resources Defense Council.


**Technology.** The industry generally embraces technology to reduce its O&M costs by leveraging in-use technologies, a practice we view as generally prudent. Examples include the industry's wide use of drone technology that reduces the cost of pole and wire inspections; battery technology, which reduces fuel costs; and advanced metering infrastructure, which reduces labor costs.

Currently, many gas LDCs and electric generation utilities are testing the blending of hydrogen with natural gas to further reduce carbon emissions. Many of these pilot programs are looking to reduce the cost of hydrogen and are testing the maximum allowable hydrogen that would be compatible with downstream appliances. We expect the industry will benefit from hydrogen tax credits or other government grants allowed under the IRA, likely incorporating about 5%-10% of hydrogen by 2035.

However, periodically the industry invests in higher-risk larger projects that rely on newer technologies, often resulting in a weakening of credit quality. For example, while Southern Co.'s recent commercial operations of nuclear power plant, Vogtle Unit 3, was a significant achievement, we already downgraded the company by two notches since it began pre-construction activities in 2009, reflecting the higher construction risks associated with this complex project. Also, we expect Ørsted--which partnered with many U.S. utilities to build offshore wind in the U.S.--to write-off as much as $6 billion associated with these higher risk projects. Additionally, we downgraded Eversource Energy by two notches since it announced its offshore wind power generation joint venture, reflecting the higher risks associated with this newer technology and longer-term project. Overall, we expect the industry will reduce its technological risks by generally maintaining its focus on smaller and lower risk projects.

**Alternative minimum tax.** The IRA of 2022 includes a 15% corporate alternative minimum tax (AMT) that we expect will weaken the financial measures of about 10% of the utility industry. The AMT is only applicable to corporations with at least $1 billion of income. Most fully integrated large utilities with a growing or significant renewable generation portfolio will generally be able to use the renewable tax credits to minimize or eliminate the AMT. However, the financial measures of large electric transmission and distribution utilities, gas LDCs, and large water utilities could all be weakened by the AMT.

**Cybersecurity.** The recent 2023 suspected cyberattacks against water and wastewater treatment facilities in Texas and Pennsylvania underscores the industry's ongoing cybersecurity risks. Because critical infrastructure assets tend to have higher exposure, the industry's ongoing vigilance in this area is critical to maintaining credit quality.

**Municipalization.** Municipalization is the transferring of a privately owned utility to a public ownership. While such occurrences are infrequent and rare, in 2023 two ballot proposals explored these options. In both instances, the city of El Paso, Texas, and the state of Maine soundly rejected such proposals. Other cities, including San Diego, continue to explore these alternatives and we will continue to monitor these developments, including their impact on credit quality.

# Related Research

- North American Utility Regulatory Jurisdictions: Some Notable Developments, Nov. 10, 2023
- A Storm Is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality, Nov. 9, 2023
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- A Closer Look At The Three Major California Investor-Owned Electric Utilities Amid The 2023 Wildfire Season, Oct. 24, 2023
- Credit FAQ: What's Behind Our Recent Actions On Investor-Owned Utilities In Connecticut?, Sept. 28, 2023
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- Although Commodity Costs Are A Pass Through For Utilities, They Still Affect Credit Quality, Sept. 6, 2023

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# Regulatory Friction Is Constraining Cost Recovery For North American Investor-Owned Utilities


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