"DECOUPLING" FOR ENERGY DISTRIBUTORS: CHANGING 19TH CENTURY TARIFF STRUCTURES TO ADDRESS 21ST CENTURY ENERGY MARKETS

Jeff D. Makholm, Ph.D[*]

Synopsis: In 21st century energy markets, energy distribution systems are wrestling with tariff designs left over from the 19th century when gas distributors manufactured their own gas, and electricity distributors generated their own power. For both, profits were "coupled" to the spinning gas and electricity meters that measured their customers' energy consumption. That coupling has prompted two widespread concerns in new energy markets with their distribution-only gas (and in some cases electricity) utilities. First, the rising price of gas has made average gas use fall and spinning meters to slow down, alarming gas distributors who now see a built-in obsolescence in their traditional rate-setting methods. Second, conservationists, for their part, are alarmed that the traditional profit incentive for distributors inherent in the coupling to those spinning meters may hurt wider energy conservation efforts. While issues stem from the traditional design of all energy distributors' tariffs, changing basic tariff design practices in United States regulation is never easy. It is only the gas distributors' "decoupling" efforts that have gathered growing support from both utilities *and* regulators.

I. INTRODUCTION

As the price of natural gas continues to rise, pushed upward by its relatively recent role as the premium fuel for generating electricity, gas consumers are doing what we expect of them in a market economy: they are using less. At the same time, given larger homes, more air conditioning, and a greater use of electronic gadgets, electricity customers are using more power per capita than ever. But, as many gas and electricity distributors continue their 19th century

[*] Senior Vice President, NERA, Boston, Massachusetts. Dr. Makholm has a Ph.D. in economics from the University of Wisconsin-Madison. He has been affiliated with NERA since 1984 and specializes in the economics of regulated industries in the United States and abroad. This is an expanded version of a paper given at the American Gas Association's Thirtieth Annual Legal Forum in Vail, Colorado, July 16th, 2007. Wayne P. Olson, Alexander Walsh, and Joshua Rogers of National Economic Research Associates, Inc. (NERA) provided research help. Hethie Parmesano of NERA provided helpful comments.

practice of depending on spinning meters to collect the fixed costs of their local pipeline and wires systems, they face issues that did not arise decades ago. For gas distributors, declining customer use makes meters spin more slowly—causing rates to be obsolete as soon as the ink is dry on regulatory orders. For both gas and electricity distributors, tying financial performance to spinning meters is perceived to be a barrier to encouraging energy efficiency in an era of heightened concern with climate change and an increasing focus on energy conservation.

Ratemaking for American utilities has long depended on objective, known, and measurable "test year" costs and quantities—part of the foundation of those companies' reliable regulation and high creditworthiness. Few question the basic soundness of the American ratemaking process that uses such objective cost information and sales quantities. The problem lies in how those costs are collected from most consumers. When utilities' volumes drop off and meters spin more slowly, collecting fixed costs through volumetric pricing with test year quantities will fail to allow companies to recoup those costs. Conversely, anything that can make the meters consistently spin more quickly falls to the distributors' bottom-line profits. Both problems point to a conflict between the structure of costs and the structure of regulated tariffs in a changed energy market. The conflict would appear to be spurring an increase in rate cases by gas distributors to keep up with falling loads—or in any event the incentive to spur increased energy consumption by any distributor whose profits are tied to those spinning meters.

"Decoupling" for energy distributors is a strange term that vaguely refers to that very old link between spinning meters and utility cost collection. It describes the movement in a number of states to change the way distributors collect their costs. It characterizes an inevitable and inescapable problem arising from institutional rigidities in the practice of regulating distributors, combined with the new gas and electricity markets that distributors were so instrumental in creating. It has attracted a good deal of commentary and objection, much of it misplaced. It has also created allies of environmentalists and gas utility managements—a seemingly unexpected coalition.

Decoupling means breaking the link between distribution revenue (not including the gas or electricity) and those spinning meters. That raises a question: Why, if distribution costs have so little to do with how fast the meters spin, do regulators make utilities rely on that uncertain vehicle to collect their costs in the first place? The answer lies in *history* and *institutions*. Both gas and electricity distributors are well over a century old and once had a very different type of business. Also, commissioners are rarely interested in changing what seems to work in favor of new reasoning or methods.

The following parts of this paper describe the origins of the "coupling" of distribution tariffs (Section II), the reason why those practices have posed a new problem for gas distributors in particular (Section III), changes in tariff design for interstate pipelines that illustrate one remedy for those spinning meters (Sections IV and V), and some of the public policy debate surrounding the implementation of "decoupled" distribution tariffs (Section VI). Section VII concludes.

II. A CENTURY OF DISTRIBUTION RATEMAKING PRACTICE

The operation and regulation of investor-owned utilities has a uniquely long history in the United States. In most of the rest of the world, major investor-owned utilities only appeared after the privatization wave of the late 20th century, and their regulatory institutions are new and untested. But, in the United States, the late 19th and early 20th centuries saw the creation of the legal, accounting, and procedural rules that would allow capital to flow into the sector while at the same time protecting the public's interest in fair and reasonable utility rates. With such a long evolutionary history in its regulatory institutions, it should be no surprise that basic changes come slowly in the United States and are hard fought among experienced interest groups. That is true also of the basic character of gas and electricity rates—they are rooted in practices more than a century old.

Gas distribution is the oldest of modern utility services. Gas utilities first provided a product to American consumers in the early 1800s. The Gas Light Company of Baltimore, founded in 1816, was the first gas utility in the United States.[1] It was soon followed by the Boston Gas Light Company in 1822 and the New York Gas Light Company in 1825. These early utilities produced manufactured gas via a number of processes performed on some form of carbon, usually coal. Gas was expensive and generally used only for lighting—coal was the fuel of choice for urban home heating in the northern states. While the original distributor bills were rendered on a "per burner per consumer" basis, the perfection of the wet gas meter led to the institution of volumetric gas sales around 1834.[2] Customers could then be charged according to their usage. Since gas production was the largest expense for early gas utilities, this new system better matched consumer payments with the gas utilities' costs of manufacturing gas.

While natural gas was discovered around the same time, it was more difficult to market to consumers in major cities. Manufactured gas could be sold anywhere that coal could be transported, stored, and processed. Natural gas was very difficult to store in a place near its markets and needed to be transported from its location in the field to the consumer by pipeline. Roughly forty years after the manufactured gas utility industry first arose, the first natural gas transport company was founded in 1858 in Fredonia, New York, where the first natural gas field had been developed a few decades before.[3] From that date onward through the 1930s, when major advances in pipeline welding allowed for its long-distance interstate transportation, natural gas posed an increasing threat to the manufactured gas industry and its coal suppliers.

There was a great deal of rivalry between different sources of fuel in the 1920s and early 1930s (before the Great Depression halted gas pipeline construction until the end of World War II). Gas pipelines at the time were unregulated at the federal level. They pushed into some northern United States

1. Gas Light Company of Baltimore was formed in 1816 at the instigation of the famous American portrait painter Rembrandt Peale and a local scientist who had experimented with ways of manufacturing illuminating gas, Dr. Benjamin Kugler. Peale formed an art museum and arranged to light it with Kugler's gas, made from distilling pine tar. *See* AM. GAS ASS'N RATE COMM., GAS RATE FUNDAMENTALS 2 (4th ed. 1987).

2. *Id.*

3. *Id.* at xviii.

cities without any federal certificate in the face of major objections from coal companies that refused to grant gas pipelines rights-of-way into regions of the country considered "coal territory."[4] Coal interests objected to the transition to natural gas on the basis of a number of self-serving grounds. Among other things, the coal interests argued that: (1) natural gas pipelines would displace the skilled labor that was needed in the coal manufacturing plants; (2) natural gas was a luxury commodity; (3) keeping natural gas in the South would foster regional economic development; and (4) while both coal and gas are exhaustible resources, gas reserves were estimated in decades and coal reserves in centuries.[5] Ultimately, none of these various objections of the coal industry halted the advance of natural gas into the coal markets. By the late 1940s and early 1950s, most gas distributors in the United States had switched over to natural gas and retired their manufactured gas facilities.[6]

This switch caused a major change in the gas distribution utility business model. Now that gas was merely purchased by distributors on behalf of customers, the distributors' own costs became largely invariant to the volume of gas sold. Much of consumers' gas costs afterwards became a function of rising natural gas commodity prices and interstate transportation charges—both pass-through expenses of the distributor—leaving the share of the distributors' own costs shrinking as a percentage of the total bill. This was particularly true after 2000 as the price of gas rose sharply, as shown below in Figure 1.[7]

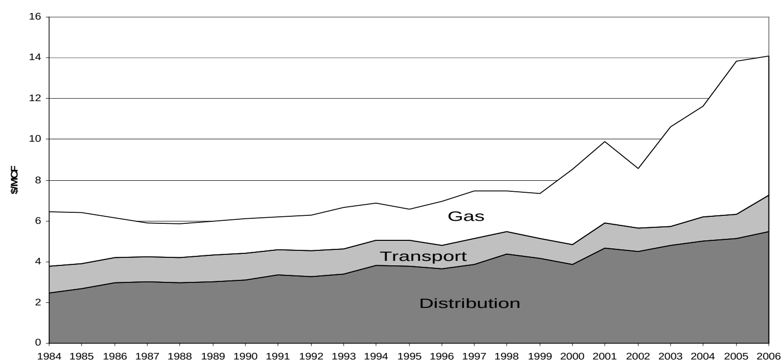

Figure 1: Residential Gas Price Components 1984-2006.[8] *Source: U.S. Energy Information Administration (various issues).*

4. CHRISTOPHER J. CASTANEDA, INVISIBLE FUEL: MANUFACTURED AND NATURAL GAS IN AMERICA, 1800-2000 111 (Twayne Publishers 1999).

5. Ralph K. Huitt, *Federal Regulation of the Users of Natural Gas*, 46 AM. POL. SCI. REV. 455, 455-456 (1952).

6. CASTANEDA, *supra* note 6, at 144.

7. The corresponding components of final electricity prices to customers are not so easy to obtain, and they are highly dependent on the region of the country and whether the electricity companies have been restructured. In general, however, the greater share of costs (perhaps 60%) for delivered electricity is accounted for by generation, with 10% for transmission and 30 for distribution.

8. These figures were derived by taking the differences between final customer prices, city-gate prices, and wellhead prices.

The provision of electricity service to major cities followed gas by some fifty years, although that industry also focused on measuring the energy provided to customers rather than the cost of getting it to them. On September 4, 1882, the first central station electric generating plant was put into operation by the Edison Electric Illuminating Company and supplied electricity for lighting purposes from its Pearl Street location in New York City.[9] Other utilities such as the Chicago Edison companies and numerous municipals followed, taking advantage of the large-scale economies present in electricity generation famously exploited by industry entrepreneur Samuel Insull.[10] This trend towards ever-greater generation, in conjunction with certain early innovations in electricity transmission, brought the electric industry closer to its modern state.[11]

While utility operators were discovering the broader economics of the industry, they also grappled with the problem of measuring the amount of electricity used by customers. Although the first United States patent on electricity measurement was taken out in the 1870s, changes in the end-use of electricity and method of transmission, endemic to the infancy of the industry,[12] posed obstacles to the development of a universal meter. This problem was in large part solved in 1894, with the invention of a commercially viable induction watt-hour meter by Oliver B. Shallenberger.[13] Further evolution of metering devices produced smaller and less expensive devices. These discoveries allowed electric companies to measure the amount of electricity consumed by their customers at increasingly lower costs.

In today's market, with millions of household and small commercial gas and electricity customers to serve, the pricing practices of most distributors are still restricted to the volumetric pricing of the 19th and early 20th century for the simple reason that household and small business meters still only measure the flowing gas and electricity supply. The fundamental tariff equation they use to develop their rates (Equation 1) is as follows:

$$Distribution\ Volumetric\ Rate = \frac{Test\ Year\ Distribution\ Cost\ of\ Service}{Test\ Year\ Volumes\ Distributed}$$

---

9. NEIL BALDWIN, EDISON, INVENTING THE CENTURY 137-8 (Hyperion 1995) .

10. *See generally,* Hon. Richard D. Cudahy & William D. Henderson, *From Insull to Enron: Corporate (Re)Regulation After the Rise And Fall of Two Energy Icons*, 26 ENERGY L.J. 35, 35-110 (2005).

11. This innovation in electricity transport was made possible through the invention of the alternating current system by Nikola Tesla. It was marketed by George Westinghouse, a purchaser of such inventions. JILL JONNES, EMPIRES OF LIGHT: EDISON, TESLA, WESTINGHOUSE, AND THE RACE TO ELECTRIFY THE WORLD 159-63 (Random House 2003).

12. At its birth, the electric utility business was not nearly as well defined as it is today. The industry struggled with questions such as whether the focus of the business should be on small-scale generators for individual users, or large-scale generators that could serve broad geographic areas, and whether alternating or direct current should be used for electricity transmission. The industry was also unsure if the primary customers of electricity would be city lighting and streetcar services, residential consumers, or industrial consumers, and if the industry would be limited to urban areas due to the costs of transporting electricity.

13. This invention was also known as the "out-of-phase meter." The device employed a small induction motor with the voltage and current coils 90 degrees out of phase with each other.

Actual tariff structures for many United States distributors are merely variants of this basic volumetric rate formula. Actual volumetric tariffs may contain "declining blocks" or other ways to create tariffs that provide for some form of crude volume discount (or "inverted blocks" to mimic crudely a kind of peak-load pricing or to provide a subsidy to low-use consumers).[14] Most distributors also have small monthly distribution service charges. Such practices for distributors are old and idiosyncratic, and the basic rate structures for many have remained generally unchanged for decades. In the gas utility business, they survived not only the conversion to natural gas in the early and mid 20th century, but also the transition to deregulation of gas prices and the creation of contract carriage on the interstate pipeline network in the 1990s. In the electricity utility business, this method of charging most customers survived the demise of integrated utilities in many states and the creation of competitive wholesale generating markets.

III. A NEW TYPE OF BILLING PROBLEM FOR GAS DISTRIBUTORS

The issue of separating distribution charges from spinning meters has arisen before in United States regulation. For example, many gas distributors in the late 1980s and 1990s, led by Brooklyn Union Gas and others, instituted "weather normalization" clauses in order to free their revenue collections from the year-to-year vicissitudes of the weather—the driving force behind how fast the meters spin for those customers that use gas for heating. By the start of 2007, many states had authorized weather normalization clauses, both to economize on the cost of short-term debt in warm winters (as distributors borrow to make up for low warm-weather revenues) and also to save on management wear and tear associated with revenue streams that, while highly stable on a multi-year basis, were less than predictable year-to-year.[15]

These weather normalization clauses, which are a form of decoupling because they separate the link between revenues and weather, stopped being newsworthy in the 1990s. Why is decoupling back in the news? The reason appears in Figure 2.

---

14. An example of a declining block volumetric gas distribution tariff is as follows:

Monthy Consumption (Mcf)	Billed at: (per Mcf)	For a monthly use of 31 Mcf, the bill is computed as follows:						
First 3.0	$ 12.00	First	3.0	@	$ 12.00	per Mcf	=	$ 37.50
Next 7.0	$ 10.00	Next	7.0	@	$ 10.00	per Mcf	=	$ 70.00
Next 20.0	$ 8.00	Next	20.0	@	$ 8.00	per Mcf	=	$ 160.00
All Additional	$ 7.00	Remaining	1.0	@	$ 7.00	per Mcf	=	$ 7.00
			31.0		Total Bill			$ 274.50
					Average price of gas			$ 8.85/Mcf

15. For a list of these states, see Cynthia J. Marple, Dir., Rates and Regulatory Affairs, Am. Gas Ass'n, Address at the AGA/EEI 2007 Chief Accounting Officers Conference: Energy Efficiency and Revenue Stability: Compatible Goals (June 26, 2007), at 15, https://www.aga.org/NR/rdonlyres/7F003F22-A9F1-408B-AE1F-970AAD108A77/0/0707MARPLE.PPT.

Rising prices have made energy efficiency a priority among gas consumers, leading to the widespread use of more efficient homes, appliances, machines, and equipment. These changes in consumption patterns underlie the decline in residential gas usage per customer displayed in Figure 2. In electricity, however,

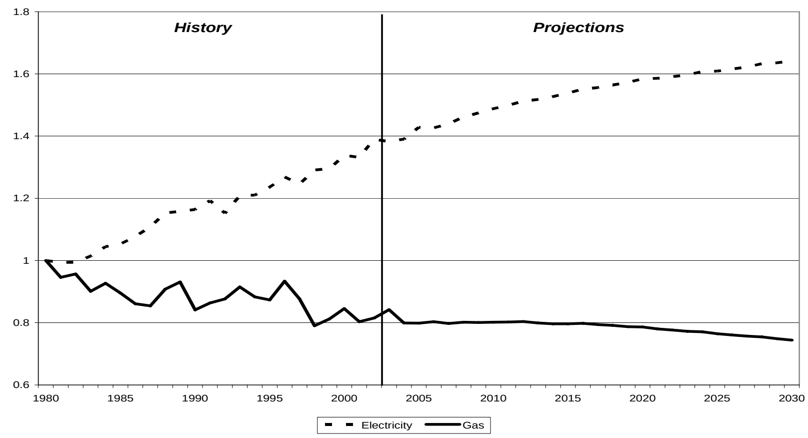

Figure 2: Per Capita Residential Electricity and Gas Consumption 1980-2030 (Index, 1980 = 1). Source: U.S. Energy Information Administration (various issues).

larger homes, more use of air conditioning, and the greater penetration of electronic equipment (including power-hungry plasma TVs) have accounted for a rising level of electricity use per customer.

The price of natural gas has increased dramatically, as illustrated in Figure 3.

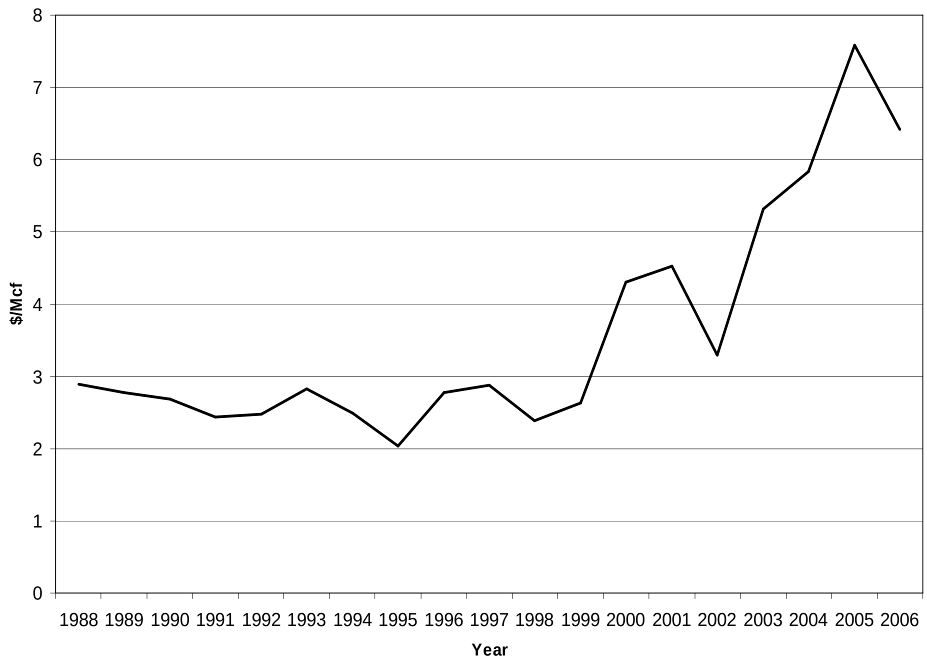

Figure 3: Natural Gas Prices, 1988–2006. Source: U.S. Energy Information Administration (various issues).

The source of this trend in gas prices is growing demand, particularly for power generation. The effect of the technological advances in combined cycle gas turbines (CCGTs) coupled with the new power markets in the United States have caused a large expansion in the construction of such plants as shown below in Figures 4 and 5. Figure 4 shows a representative collection of U-shaped average cost curves for electricity generating plants. It also shows that from 1930 to 1980 the efficient scale of low-cost generating plants dropped steadily as plants grew larger. The graph also reveals that only in the 1990s, with the appearance of CCGTs, could smaller gas plants rival and then beat the cost of the giant plants of the 1970s and 1980s. Figure 5 shows the great spike in CCGT generation capacity from 1999 through 2003. While there has been some levelling of this growth since 2003 as power markets softened, the new gas-fired CCGT plants represent a more than 10-fold increase from levels in the mid-1990s.

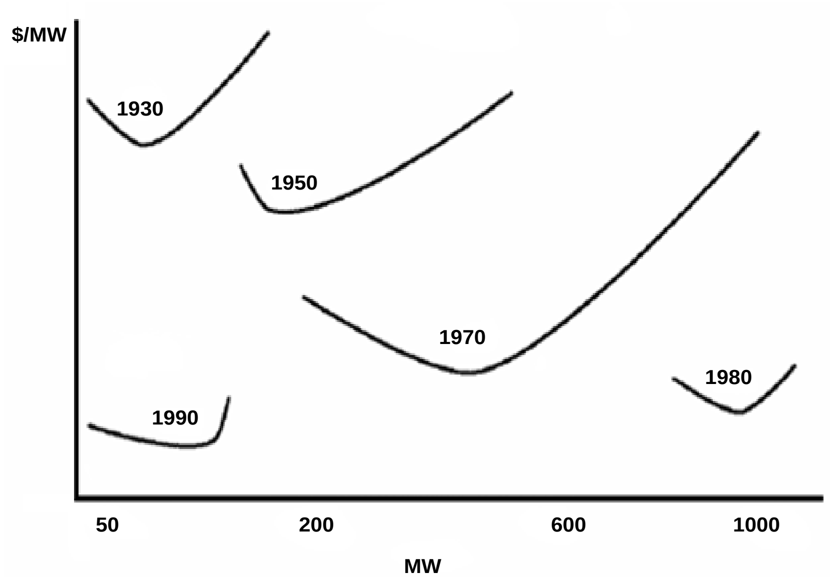

Figure 4: In the 1990s, CCGTs Reversed the Historical Trend Toward Larger Power Plants. Source: SALLY HUNT AND GRAHAM SHUTTLEWORTH, COMPETITION AND CHOICE IN ELECTRICITY 2 (Wiley 1996).

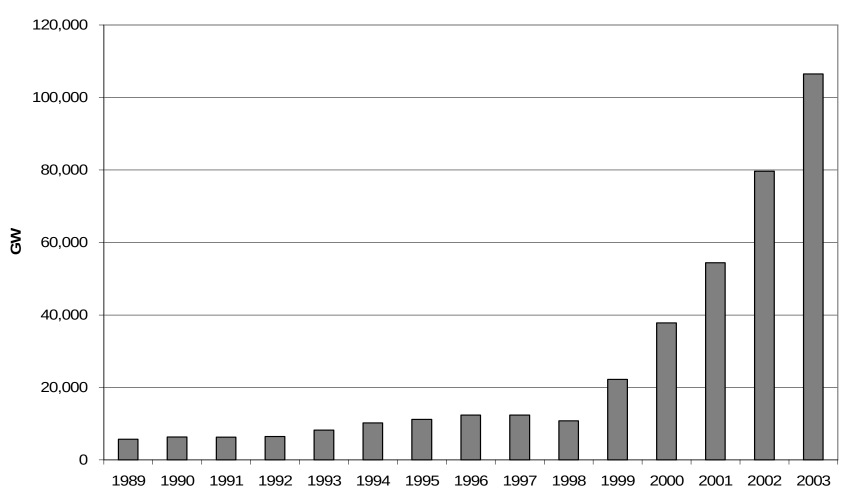

Figure 5: Net United States Capacity Combined Cycle Generation, 1989–2003. Source: NERC Electricity Supply and Demand Database 2004.

Together, these graphs demonstrate the leap in power generation with CCGT technology, as very low cost power accompanied much smaller plants, and how those plants have spurred the demand for gas as a generation fuel.

The use of gas for the new CCGT plants, the consequent rise in gas prices, and the resulting persistent decline in gas use per customer creates a dilemma for gas distributors that are still burdened with 19th century rate structures.[16] The decline in use per customer leaves distributors with only limited remedies for the problem of outdated test year volumes:

1. remove test year volumes from the denominator of the Equation 1 method and substituting some other billing factor;
2. retain a volumetric rate design but adjust those denominator volumes in Equation 1 over time to keep up with the declining volumes vis-à-vis the test year via an automatic adjustment; or
3. file new rate cases to update Equation 1 with new data.

All three remedies are in evidence in various states.

IV. THE INTERSTATE GAS PIPELINES AND SFV

After a number of revisions in the 1970s and 1980s to the structure of interstate pipeline rates, the FERC settled in the 1990s on the "straight fixed variable" (SFV) method for pipelines to collect their fixed costs. SFV charges operate as a form of "rent" of reserved space on the interstate pipeline network, rendering a regular monthly bill for customers' leased pipeline capacity regardless of how much gas flows. SFV is efficient and now largely uncontroversial at the interstate level.[17] It serves as an effective price signal for the use of assets that do not depend on the pipeline companies' actual volumes shipped.

From the 1950s through the 1980s, however, the regulated price and availability of gas in interstate pipeline transport was highly controversial. The delivery of pipeline-owned gas to the city-gate stations of distributors was central to the pipelines' business.[18] During the period of regulated gas prices, the size of the volumetric portion of the rates for interstate pipelines rose and fell under constant controversy, driven chiefly by considerations pertaining to the price of delivered gas rather than the cost of transportation. Two distinct phases of regulatory oversight marked this period:

- <u>Greater Volumetric Tariff (1942-1973)</u>. In the *Seaboard*[19] decision, the Commission directed 50% of fixed costs into the volumetric portion of pipeline tariffs, ostensibly to recognize that pipeline systems were designed to meet both peak and storage-related gas

16. This is the case whether or not the distributors have weather normalization billing mechanisms. Those mechanisms adjust year to year based on weather deviations from average, but cannot deal with lower sales over time due to a demand response to high gas prices.

17. When first mandated in 1992 as part of FERC Order No. 636, SFV shifted pipeline costs among different pipeline users, causing contention among the various winners and losers—as any change in rate design would. Order No. 636, *Pipeline Service Obligations and Revisions Governing Self-Implenting Transportation; and Regulation of Natural Gas Pipelines After Wellhead Decontrol*, [Regs. Preamples 1991-1996] F.E.R.C. STATS. & REGS. ¶ 30,939, 57 Fed. Reg. 20,393 (1992).

18. Under the Natural Gas Act of 1938, interstate pipelines were assumed to be in "the business of transporting and selling natural gas for ultimate distribution to the public . . . ." Natural Gas Act, 15 U.S.C. § 717(a) (2000).

19. *Atl. Seaboard Corp.*, 11 F.P.C. 43 (1952).

sales. With gas shortages for interstate shipments in the early 1970s, pipeline companies had difficulty meeting peak day gas sales obligations. In response to this problem, the Commission in *United*[20] increased the volumetric portion of pipeline tariffs to 75%. The Commission wanted to limit gas use by certain price-sensitive industrial end-users of gas.

- <u>Decrease in Loading (1973-1993)</u>. Beginning in the 1970s and continuing through the early 1980s, the Commission recognized the gas market conditions that it used to justify *United* no longer existed—although it believed that some minimal loading would provide pipelines with an incentive to minimize purchased gas costs.[21] Ultimately, the FERC in 1992 removed interstate pipelines from the business of selling gas to distributors at the city gate. The absence of gas sales eliminated the remaining reason to rely on a volumetric rate to collect interstate pipeline costs.

Any type of pipeline charge unrelated to capacity was apt to—and did—skew incentives. The battles over the size of the volumetric portion of the tariff generally had nothing to do with efficiently collecting pipeline costs, as such. They either served to benefit those customers taking at low load factors (who would pay a smaller overall bill compared to those with higher load factors) or would benefit the pipeline company itself (if it could construct the rates on volumes that it expected to beat in practice).

Loading capacity costs into commodity-sensitive tariffs created fights over regulated rates (among sets of customers knowingly dividing cost responsibility in a zero-sum game) and gave pipeline companies inefficient incentives to ship to customers gas supplies from every possible source and hence keep the meters spinning. The pipeline companies' practice of re-selling gas at the overall average cost of gas led many of them to purchase very expensive supplies at the margin under onerous and individually uneconomic terms. These uneconomic gas supplies bought in the 1970s and 1980s contributed to financial problems for many interstate gas pipelines by the 1980s as the older, lower-priced regulated supplies either ran out or were deregulated by the FERC or Congress. The resulting distress of the pipeline companies laid the groundwork for voluntary open access and final interstate pipeline restructuring in the 1990s. That final result, however, was largely an unscripted consequence in a volatile gas market, commodity loading of fixed costs in pipeline tariffs, and the resulting incentive on the part of interstate pipeline companies to find a way to keep those meters spinning once the largely volumetric rates had been set.

Electricity transmission has not seen the history or the extent of fights that led up to SFV rates on interstate gas pipelines. Compared to the interstate gas pipeline network, the electric transmission grid was traditionally a small, state-by-state patchwork affair with independent utilities generating, transmitting, and distributing their own electricity. The issue of efficient transmission tariff

---

20. *United Gas Pipe Line Co.*, 50 F.P.C. 1348 (1973).

21. *Atlantic Seaboard Corp., et al,* 11 FPC 43, 94 PUR (NS) 235 (1952); Opinion No. 249, *Tenn. Gas Pipeline Co., a Division of Tenneco Inc.*, 27 F.E.R.C. ¶ 63,090 at p. 65,373 (1984); *United Gas Pipe Line Co.*, 3 PUR 4th 491 (FPC 1973), *reh'g denied*, 51 FPC 1014 (1974); *Tennessee Gas Pipeline Co., a Division of Tenneco Inc.*, 36 F.E.R.C. ¶ 61,071 at p. 61,163-61,168 (1986).

design and reasonable cost allocation has arisen recently, however, with the rise of wholesale energy markets. From that patchwork of separate transmission businesses, each with its own set of "wheeling" tariffs, a more rational capacity-based set of transmission charges that reflects better the use of wider regional networks has emerged.[22]

V. SFV AT THE DISTRIBUTOR LEVEL

Implementing an SFV-type of decoupling is not as straightforward for gas or electricity distributors as it was for interstate pipelines, for two reasons. First, gas distribution meters do not generally provide information on maximum peak-day usage for the millions of distribution customers.[23] Second, since the 19th century, distributors have never structured their charges to mimic the "rent" charged by interstate pipelines under interstate pipeline capacity contracts. That is, the vast majority of small distribution customers have no limits on their ability to take gas, because gas distribution companies are obligated to serve all comers. Interstate pipelines, by contrast, serve a much more narrowly-defined clientele, composed of customers with contracts that state the levels of deliveries that are assured and the amounts that can be interrupted. Changing from volumetric to fixed charges for distribution service would change the level of many customers' overall charges—some higher, some lower. Such changes are never popular with consumers (particularly with consumers whose bills increase).

Despite the difficulties, a number of commissions appear to be adopting something like SFV rate designs for gas distributors in particular. Georgia's Legislature made SFV the standard in 1997 with Senate Bill 215.[24] Several gas distributors from Oklahoma, Kansas, Michigan, and Missouri either currently offer customers a choice between volume charges and SFV or have filed proposals with their commissions to institute such a policy. In North Dakota, an opinion from a recent Northern States Power Company's rate case identifies significant benefits that will result from adopting a new SFV-type distribution tariff structure: "[t]he new billing format will decrease the price volatility in winter gas bills. It ends unfair rate discrimination against customers living in older homes. And it helps lower the chance that [the Commission] will hear another rate case in the near future."[25]

22. In electricity, transmission pricing and cost allocation are still in their early stages as regional transmission networks develop further and adapt to the regional structuring and allocation of transmission charges. Nevertheless, some of the contention between states and utilities in a region appear to have parallels with the issues that arose before open access on the gas transmission system when pipelines operated a pooled gas system for their connected distributors. J.D. Makholm, *Electricity Transmission Cost Allocation: A Throwback to an Earlier Era in Gas Transmission,* 20 ELECTRICITY J. (2007).

23. Some meters do, but only for larger commercial and industrial classes who purchase "transportation" service from distributors.

24. S.B. 215, 97th Leg. (Ga. 1997).

25. Order Adopting Settlement, Northern States Power Company, No. PU-04-578, at 6 (N.D. Pub. Serv. Comm'n June 1,2005) (Commissioner Clark, concurring).

Other states have kept the basic volumetric element of distribution tariff structures intact but have implemented automatic adjustments. Those states are shown below in Figure 6.[26]

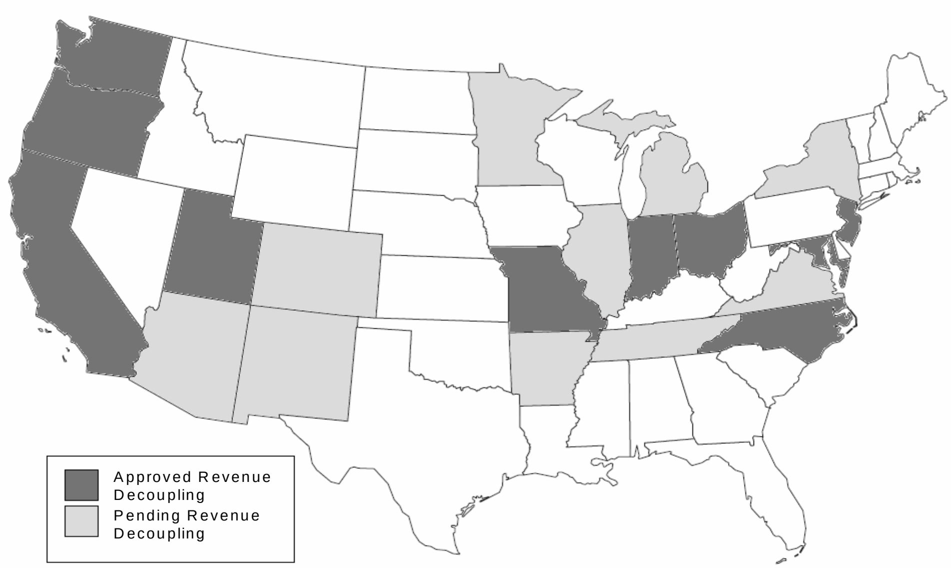

Figure 6: Natural Gas Revenue Decoupling as of April 18, 2007. Source: American Gas Association (2007)

Electricity distributors have not generally faced the imperative of declining use per customer.[27] The impetus for decoupling for electricity distributors has come from those who perceive that the distributors retain the traditional incentives to increase the spinning of those electric meters. The larger point for electricity distributors is that rate cases are disruptive and costly, as are accounting and billing methods to account for changing customer usage patterns.[28] Rising customer usage can offset increasing costs and traditionally contributes to lengthened periods between rate cases. As such, it is to be

26. Electricity and gas distributors have previously pushed for the automatic pass through of various cost items over which they have little control, and which could quickly imperil utility finances (like fuel and purchased gas costs). MICHAEL SCHMIDT, AUTOMATIC ADJUSTMENT CLAUSES: THEORY AND APPLICATION (Mich. State Univ. 1980). Some distributors in the United States have also recently been attempting to extend periodic automatic updates to other cost items, such as rising bad debt expenses and the new information technology expenses required to facilitate new markets. The efficacy of those requests for tracking various costs is outside of the scope of this paper.

27. Some integrated electric utilities are interested in decoupling as one method of dampening the demand for new capacity. Now knowing what the carbon rules are going to be, delaying capacity additions reduces their risk, and also gives them more time to meet renewable portfolio standards in an era where there is not enough renewable energy to go around.

28. In addition to the direct expenses of *ex post* adjustment to tariffs, the inevitable deferrals of cost are themselves traditional sources of risk for distributors—as such deferral accounts are sometimes targeted for less than full cost recovery.

expected that decoupling initiatives aimed at customer usage would hold no inherent allure for electricity distributors. Nevertheless, some perhaps see decoupling as part of an entire package of conservation and energy efficiency that they can pursue at the local level in collaboration with regulators and local interest groups.[29]

VI. OPPOSITION TO CHANGING DISTRIBUTOR TARIFFS

In the United States, rate cases are complex and serve as formal dispute resolution forums. It is not surprising, therefore, that a substantial change in the design of local utility tariffs would attract attention and objection—particularly those tariff designs that have survived for many decades. Such was true in the 1970s, when Wisconsin and New York pursued what was then the novel (but now well accepted) principle of *marginal-cost based pricing*.[30] The idea for such pricing for utilities had arisen by the 1940s, as economists sought more efficient solutions to electricity pricing. Professor Harold Hotelling once and for all set marginal cost as the standard by which economists judge efficient tariffs (in an article called by Professor James Bonbright "one of the most distinguished contributions to rate-making theory in the entire literature of economics").[31] Despite the seemingly self-evident nature of the benefit of marginal-cost based pricing to economists, it would take more than thirty years for commissions to study the subject actively. The practical institutional constraints faced by economists in pursuing efficient regulated prices were best expressed by Professor Emory Troxel, one of the great United States regulatory economists of the 1930s and 1940s and a pioneer in attempting to popularize the concept of marginal-cost based pricing in utility ratemaking. Troxel said of marginal-cost based pricing in 1947:

> Being administrators who like to get jobs done quickly, utility commissioners often want a simple, expedient method of earnings control. But the marginal-cost method is so complex that many regulators cannot quickly understand it or easily use it. Being practical, political-minded [people], the commissioners wish a method that is tested by experience rather than general reasoning. . . . Since these [people] are rarely interested in what they consider odd thinking, nothing short of a general upheaval in utility regulation can drive them to study the idea.[32]

Decoupling is not quite in the same league as marginal-cost based pricing as

29. State-mandated electricity distribution decoupling is in place in California and Idaho, and there is much talk of it in other states such as Massachusetts, Connecticut, and New Hampshire. California reintroduced decoupling in 2002, following the passage of legislation in April 2001 (§ 739.10), which directed the CPUC to reinstate its policy of breaking the kWh sales/revenues linkage. For detail on decoupling in Idaho, see Order No. 30267, *In The Matter of The Investigation of Financial Disincentives to Investment in Energy Efficiency by Idaho Power Company*, No. IPC-E-04-15 (Idaho Pub. Utils. Comm'n 2007).

30. Indeed, it was not until 1974 that the Wisconsin Public Service Commission, under Chairman Richard Cudahy, opened a general investigation into the application of marginal-cost based pricing for the electric utilities in that state in a case involving Madison Gas and Electric Company. *See* Richard D. Cudahy, *Rate Redesign Today: The Aftermath of Madison Gas*, PUBLIC UTILITIES FORTNIGHTLY, May 20, 1976, at 15-19. This was one year before Professor Kahn, then Chairman of the New York Public Service Commission, opened a similar marginal-cost based pricing investigation in his own state. "Chairman Kahn" has always lamented to his colleagues, this author among them, that Chairman Cudahy beat him to the punch.

31. Harold Hotelling, *The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates*, 6 ECONOMETRICA 242, 242-269 (1938); James C. Bonbright, *Major Controversies as to the Criteria of Reasonable Public Utility Rates*, 30 AM. ECON. REV. 379, 385 (1941).

32. EMORY TROXEL, ECONOMICS OF PUBLIC UTILITIES 463 (Rinehart Company, Inc. 1947).

a revolution in ratemaking for United States distributors, but it has attracted its own measure of controversy and resistance based on many decades of volumetric distributor pricing. Critics of decoupling claim that it "shifts risks" to ratepayers or that an after-the-fact adjustment of billing determinants constitutes proscribed "retroactive ratemaking," or that it is akin to "taxing consumers for the benefit of protecting utilities from financial harm . . . ."[33] For example, a July 2004 Staff Report from the New York State Public Service Commission criticized decoupling as contributing to the uncertainty in customer bills, increasing the risk that the customers would bear, and as a result freeing distributors from that risk.[34] In June of this year, the Massachusetts Department of Public Utilities opened an investigation to evaluate current rate structures. Within the proposal, the commission explicitly acknowledged a potential challenge in dealing with the issue of risk, allowing that the institution of decoupling "could materially alter the distribution of risks among the company, its shareholders, and its customers."[35] Some Commissions (such as New York and Maryland) have made explicit downward risk adjustments to the allowed rate of return to account for this presumed lessening of "risk." [36]

The arguments about risk generally proceed from a colloquial, rather than precise terminology.[37] The cost of capital in the market is widely held to be driven by investors' perception of business and financial risk. These two well-defined types of risk are not affected by decoupling, as such. Weather-related decoupling for gas distributors deals with revenue deviations from a stable and predictable average. It is less costly for distributors, both in terms of short-term borrowing costs and management time, not to have distribution revenue tied to those deviations.[38] The conservation-related decline in average gas customer use is a known, but recent, trend. When combined with a volumetric distribution

33. To see the review of such positions see Ken Costello, *Natural-Gas Revenue Decoupling: Good for the Utility or for Consumers?*, PUBLIC UTILITIES FORTNIGHTLY, Apr. 2007, at 46-48.

34. Staff Report, *Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation*, Case 03-E-0640, at 7-9 (N.Y. Pub. Serv. Comm'n July 9, 2004). The Commission has since deemed revenue decoupling mechanisms a necessary part of their regulatory policies. *See* Order Requiring Proposals for Revenue Decoupling Mechanisms, *Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation* and *In the Matter of the Investigation of Potential Gas Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation,* Nos. 03-E-0640, 06-G-0746 (N.Y. Pub. Serv. Comm'n April 20, 2007).

35. Vote and Order Opening Investigation, *Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources*, No. D.P.U. 07-50, at 17 (Mass. Dep't of Pub. Util. June 22, 2007).

36. *See* Order No. 81518, *In the Matter of the Application of Delmarva Power and Light Company for Authority to Revise its Rates and Charges for Electric Service and for Certain Rate Design Changes*, No. 9093 (Maryland Pub. Serv. Comm'n July 19, 2007); and Order Establishing Rates for Gas Service, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service*, No. 07-G-0141 (N.Y. Pub. Serv. Comm'n December 21, 2007).

37. There is nothing unusual about using imprecise language in contested ratemaking proceedings, and it happens often enough. *See* Jeff D. Makholm, *The Risk Sharing Strawman*, PUBLIC UTILITIES FORTNIGHTLY, July 7, 1988, at 24-29. In that 1988 paper, I provided a listing of twenty-one different cases involving prudence, excess capacity, rate design, and fuel and gas cost adjustments where the term "risk sharing" had, through imprecise language pertaining to risk, confused rather than crystallized the regulatory issues at stake.

38. For healthy gas utilities, the short-term borrowing needs related to a lack of weather-normalization decoupling appear to have no discernable effect on credit ratings.

rate design, this trend produces a known, but novel, shortfall. There are various ways to deal with the anticipated shortfall, with perhaps the most expensive for consumers being the triggering of rate cases.

In neither case does lessening the reliance by gas distributors on the volumetric tariff affect what is generally understood as the "regulatory compact"[39] between utilities and their customers—nor does it lessen materially the business or financial risk for which investors require compensation.

VII. CONCLUSION

While decoupling for energy distributors could be a non-controversial issue, nothing involving a basic change in tariff design practices is simple in United States regulation. The institutions upon which United States regulatory practices rest are decades old, and for the most part they permit the economical financing of utilities and the protection of consumers under a well known regulatory compact. Administratively, "what works," in our system of regulation, is hard to wipe away with new methods and new reasoning.[40]

For gas distributors, the 19th century tariff structures were reasonably suitable until the 1990s. But with new energy markets, and a new technology for using gas for electricity production, those old tariff structures are showing their age. Distributors have growing incentives to avoid the adverse effects of these 19th century rates, and new tariff structures are appearing in many jurisdictions to replace them. This trend has the potential to reduce the frequency of rate cases. It is likely that the trend—an efficient one for gas distributors in particular—will spread.

Decoupling for electricity distributors appears to be motivated mainly by a public interest desire to remove whatever incentives may exist for distributors to promote sales of electricity between rate cases. In the context of ratemaking only, electricity distributors would see any growth in customer volumes compared to test year levels as a traditional way to countervail rising costs. Decoupling in this context, which would entail administrative costs, rate changes, and the loss of benefits associated with electric meters spinning more quickly as the average customer uses more electricity, would not be inherently attractive to distributors. However, they may accept the initiative as part of a larger package of state-sanctioned public interest initiatives (like subsidized conservation programs). But the spur to pursue decoupling for these electricity distributors is different, and less fundamentally pressing, than for their gas distributor cousins.

39. The compact in general terms is as follows: First, in return for a monopoly franchise, utilities accept an obligation to serve all comers. Second, in return for agreeing to commit capital to the business, utilities are assured a fair opportunity to earn a reasonable return on that capital. Irwin M. Stelzer, *The Utilities of the 1990s*, WALL ST. J., Jan. 7, 1987, at 20.

40. Justice Oliver Wendell Holmes said in his treatise on the law: "Most of the things we do, we do for no better reason than that our fathers have done them or that our neighbors do them . . . ." MARTIN G. GLAESER, OUTLINES OF PUBLIC UTILITY ECONOMICS vi (The Macmillan Co. 1927) (quoting OLIVER WENDELL HOLMES, THE PATH OF THE LAW).