

**IMPLICATIONS OF A NEW PUHCA FOR  
THE ELECTRIC INDUSTRY AND REGULATORS**

Kenneth W. Costello  
Associate Director

Edward H. Jennings  
Professor of Finance  
The Ohio State University

Timothy W. Viezer  
Graduate Research Associate

**THE NATIONAL REGULATORY RESEARCH INSTITUTE**

The Ohio State University  
1080 Carmack Road  
Columbus, Ohio 43210-1002  
(614) 292-9404

August 1992

This report was prepared by The National Regulatory Research Institute (NRRI) with funding provided by participating member commissions of the National Association of Regulatory Utility Commissioners (NARUC). The views and opinions of the authors do not necessarily state or reflect the views, opinions, or policies of the NRRI, the NARUC, or their contributors.



## **EXECUTIVE SUMMARY**

Later in 1992, the electric industry is likely to see the passage of legislation facilitating the entry of new generators in the wholesale power markets. An amended Public Utility Holding Company Act (PUHCA) could be enacted into law giving a new group of power producers the opportunity to become important players in the future electric industry. A new PUHCA would lift key entry restrictions into wholesale power production. Specifically, it would provide nonutility companies an expanded opportunity to participate as power producers and allow utilities opportunities to produce power outside of their retail service areas.

As of mid-summer, it remains uncertain what effect a new PUHCA would have on the electric industry. Assuming it would stimulate the growth of the independent power industry, the electric industry would likely undergo fundamental changes with important implications for both retail electricity consumers and state public utility commissions.

One conceivable outcome is a radical change in the structure of the electric industry that could see it become less vertically integrated. More power generation could come from independent producers employing the most economical technologies to serve wholesale power markets. While the optimal industry structure is unknown, it is intended that a new PUHCA will steer the industry toward a more economical structure allowing market forces to discover the most efficient producers. Although independent power producers ultimately may not play a major role as power generators, a new PUHCA will give them a chance to compete more equally with alternate sources of new resources (both supply side and demand side). As a policy matter, independent power production should thrive only if it can offer the nation an economical source of new power supply.

A new PUHCA would result in traditional regulated utilities increasingly searching for new markets in which to sell the power they produce and to buy the power

they need to serve their retail customers. These activities should advance competition in the wholesale power markets, leading over time to the vertical disintegration of utilities.

State public utility commissions will play a pivotal part in affecting independent power production and its effect on increasing competition in the wholesale power markets. Through their actions and policies, they will provide the bedrock for determining how utilities can and will pursue new supply sources needed to meet the demand of their retail customers. Incentives and opportunities for power purchases by utilities will depend largely on the environment created by state regulators. Regulators may have to reduce regulatory impediments to elicit more economical purchases of firm wholesale power by utilities.

State regulators will have particular concern over utilities forming wholesale power production subsidiaries. Possible anticompetitive activities by operating utilities and utility holding companies with wholesale power subsidiaries imply that state regulators will have to stand guard more intensively against potential abuses that can harm retail customers. A new PUHCA would likely give state commissions more certain authority to protect retail customers from these abuses. While some state regulators may believe they could cope with possible abuses under their current procedures, others may decide to take more dramatic actions such as increasing staff resources and even adopting a different regulatory mechanism. In either case, state regulators would have to reaffirm their ability to prevent abuses by utilities and their wholesale power affiliates.

The gains of a new PUHCA to retail customers will depend on several factors. The extent to which new independent power producers can generate electricity at low cost with the economic gains spread to the retail market will determine the benefits to end-use electricity consumers. These benefits, in turn, will hinge largely on the practices and policies of regulators--namely, the Federal Energy Regulatory Commission in affecting wholesale power pricing and transmission access and the state commissions in affecting incentives and opportunities for utilities to purchase firm wholesale power. Benefits will also depend on the long-term operating performance of independent power facilities and on increases in competitive forces induced by the easier entry of new wholesale power producers.

## TABLE OF CONTENTS

	Page
LIST OF FIGURES .....	vii
LIST OF TABLES .....	viii
FOREWORD .....	ix
ACKNOWLEDGEMENTS .....	xi
 Chapter	
<b>1 Introduction</b> .....	1
<b>2 Historical Overview of PUHCA</b> .....	5
The Early Days .....	5
The Era of Utility Holding Companies .....	9
Later Events .....	14
<b>3 Power Generators in the Electric Industry</b> .....	17
Recent Changes .....	17
Different Power Generators .....	19
How a New PUHCA Would Affect Different Power Generators .....	24
<b>4 The Implications of a New PUHCA for     Retail Consumers</b> .....	29
<b>5 The Major Components of a New PUHCA</b> .....	35
<b>6 Remaining Obstacles for Independent     Power Production</b> .....	47
Transmission Access .....	47
Self-Dealing .....	49
Demand-Side Initiatives .....	50
Regulatory Incentives .....	51

**TABLE OF CONTENTS--Continued**

	Page
<b>7</b> <b>New Challenges for Regulators</b> .....	53
<b>8</b> <b>Conclusions</b> .....	61
Appendix	
<b>The Financial Leverage Issue</b> .....	63
Introduction .....	63
The Naive Capital Structure .....	64
The Modigliani and Miller Capital Structure .....	67
Perfect Capital Markets .....	69
Tax Modifications to the M & M Capital Structure .....	71
Other Adjustments to the M & M Capital Structure .....	74
The Real World Cost of Capital .....	75
The Cost of Capital Advantage for the NUG .....	76
Summary and Conclusions .....	82

## LIST OF FIGURES

	Page
A-1 Graphical Representation of the Cost of Capital .....	66
A-2 Graphical Representation of the Cost of Capital Under M & M Conditions .....	70
A-3 Graphical Representation of the Cost of Capital Under M & M Conditions Including Corporate Taxes .....	73
A-4 Consensus Cost of Capital Reflecting Real World Conditions .....	77
A-5 Hypothetical Electric Utility Cost of Capital Curve .....	79

## LIST OF TABLES

Table	Page
1-1 Major Arguments Advanced during PUHCA Debate .....	2
2-1 SEC Jurisdiction Over Utility Holding Companies .....	12
3-1 Different Categories of Power Generators .....	20
3-2 Characteristics of Different Power Generators .....	21
3-3 PUHCA Restrictions on Forming Wholesale Power Facilities .....	25
4-1 Factors of Benefits to Retail Consumers .....	33
5-1 Features of New PUHCA in Senate Energy Bill .....	37
5-2 PUHCA Issues for Joint House-Senate Conference .....	41
7-1 Implications of New PUHCA for State Regulators .....	54
A-1 Hypothetical Income Statement .....	65
A-2 Alternative Investment Strategies .....	68
A-3 Hypothetical Income Statement Including Corporate Income Taxes .....	72
A-4 Alternative Investment Strategies with Corporate Income Taxes .....	72



## **FOREWORD**

The U.S. Congress is currently debating whether the Public Utility Company Holding Act of 1935 (PUHCA) should be amended to facilitate the entry of a new class of power generators into the electric industry. The odds are good that some federal legislation will be passed this year advancing this goal. New legislation could have consequential effects on both the future structure of the electric industry and on state public utility regulation.

The major objective of this report is to assist state commissions in better understanding what effects a new PUHCA could have on both the electric industry and state regulation. It is to this end that we believe the report will be valuable to our clientele.

Douglas N. Jones  
Director  
Columbus, Ohio  
August 14, 1992



## **ACKNOWLEDGEMENTS**

The authors gratefully acknowledge the comments of Dr. Douglas N. Jones, Mr. Robert E. Burns, and Mr. John Borrows of the NRRI, and Mr. Russell Profozich of the U.S. Department of Energy. The authors also appreciate the editing of Mr. David Wagman and the typing and patience of Ms. Marilyn Reiss.

# CHAPTER 1

## INTRODUCTION

The time has come for state public utility commissions (PUCs) to begin preparing for the day when the Public Utility Holding Company Act (PUHCA) will no longer severely constrain electric utilities from participating in interstate, nonintegrated power generation activities. While the debate over the status of PUHCA continues, it is now likely that major amendments to PUHCA could be enacted into law before the end of 1992. After several years of exhaustive and sometimes bitter debate in Congress,<sup>1</sup> the battle over whether PUHCA should be amended is coming to an end with proponents of change apparently being the victor (see Table 1-1 for a summary of the arguments presented by participants of the PUHCA debate).<sup>2</sup>

A new PUHCA would change the structure of the electric industry. Specifically, it would accelerate the industry's movement away from vertical integration and toward more competition among power generators. According to proponents of change, a new

---

<sup>1</sup> Major interest groups participating in the PUHCA debate include the electric utility industry (split between "retailers" and "wholesalers"), nonutility generators, state public utility commissions, consumer groups, and the natural gas industry.

<sup>2</sup> A list of the benefits and costs of a new PUHCA is contained in U.S. Department of Energy, *Analysis of Options to Amend the Public Utility Holding Company Act of 1935*, Technical Annex 1 (Washington, D.C.: U.S. Department of Energy, 1991); U.S. General Accounting Office, *Electric Supply: Potential Effects of Amending the Public Utility Holding Company Act*, GAO/RCED 92-52 (Washington, D.C.: U.S. General Accounting Office, January 1992); Scott Hempling, "Confusing 'Competitors' with 'Competition,'" *Public Utilities Fortnightly* (March 15, 1991): 30-32; Richard L. Gordon, "The Public Utility Holding Company Act: The Easy Step in Electric Utility Regulatory Reform," *Regulation* (Winter 1992): 58-65; and Philip R. O'Connor, Wayne P. Olson, and Gerald M. Keenan, *PUHCA Reform: Exploding the Myth of Deregulation* (Chicago, IL: Palmer Bellevue Corporation, September 1991). The U.S. DOE study estimated a new PUHCA, at the minimum, would reduce the expected capital cost for new generating capacity between \$300 million and \$1.8 billion per annum by the year 2000.

**TABLE 1-1**  
**MAJOR ARGUMENTS ADVANCED DURING PUHCA DEBATE**

---

Arguments for Amendment:	Arguments Against Amendment:
<ul style="list-style-type: none"> <li>• Increase number of wholesale power producers</li> <li>• Shift power generation to lower-cost sources</li> <li>• Advance competition in electric industry</li> <li>• Move electric industry toward more optimal structure</li> <li>• Shift risk away from retail consumers</li> <li>• Lower entry cost of new producers</li> <li>• Stimulate pressure for more open transmission access</li> <li>• Create more equal competition among wholesale power producers</li> </ul>	<ul style="list-style-type: none"> <li>• Erode state authority</li> <li>• Diminish coordination (scope) economies</li> <li>• Jeopardize reliability of electric power systems</li> <li>• Enhance self-dealing abuses</li> <li>• Enhance cross-subsidization</li> </ul>

---

Source: Authors' construct.

PUHCA would facilitate the economical entry of power entrepreneurs, called "independent power producers," into an industry long dominated by vertically integrated utilities. New legislation also

would allow the access of electric utilities to geographically dispersed markets. Although as of now the degree of enhanced competition stimulated by the entry of new power producers lacks certainty, it is indisputable that the electric industry ultimately would undergo dramatic changes in part because of a new PUHCA.<sup>3</sup>

The mission of this report is two-fold. First, it will identify those features of new PUHCA legislation that will most affect the electric industry and regulators. Although at the time of this writing no legislation has been signed into law, the direction of the debate along with actual bills passed by the Senate and the House manifests the likely components of final legislation.<sup>4</sup> A joint House-Senate Conference will reconcile differences in the two bills.<sup>5</sup>

Second, and more importantly, this report will examine the implications of a new PUHCA for regulation. Both the Federal Energy Regulatory Commission (FERC) and state commissions will face new demands in assuring that the growth in independent power production will benefit electricity consumers. Identifying these demands as well as the options available to regulators to deal with them will be this report's major objective.

---

<sup>3</sup> The experiences with independent power production so far suggest that this source of new power is reliable. This should come as no surprise since independents have access to the same technologies and expertise as utilities in constructing and operating power plants. See, for example, U.S. General Accounting Office *Electricity Supply: Potential Effects of Amending the Public Utility Holding Company Act*; and P. J. Adam, "Reliability of Non-Utility Generation," presented at Electric Utility Business Environment Conference, Denver, Colorado, March 18, 1992.

<sup>4</sup> These bills are the U.S. Senate "National Energy Security Act of 1992," S. 2166, 102d Congress, 2d Session (February 19, 1992); and U.S. House of Representatives, "Comprehensive National Energy Policy Act," H.R. 776, 102d Congress, 2d Session (May 27, 1992).

<sup>5</sup> At this writing, it is expected that the conference will send out a bill to be signed by the President by early fall of this year.

## CHAPTER 2

### HISTORICAL OVERVIEW OF PUHCA

The Public Utility Holding Company Act of 1935 was a legislative response to the consolidation of privately owned electric utilities that rapidly spread during the early decades of the industry's existence. Understanding the rationale for PUHCA requires a knowledge of the events both within and outside the electric industry that took place prior to its passage. The following provides a brief historical overview of the electric industry up to 1935.

#### The Early Days

The late 19th century was a time of innovation, falling energy prices, and high economic growth. Investors sought the promise of huge profits by financing many of the inventors who competed to develop practical electrical equipment. Competition came from all sides within the industry, but the dominant gas companies appeared to be the new technology's biggest threat. According to Thomas Edison, the gas companies "were our bitter enemies, keenly watching our every move and ready to pounce upon us at the slightest failure."<sup>1</sup>

To combat the infant electric industry, New York's contentious gas firms merged into Consolidated Gas Company and lowered their prices. Although natural gas would remain less expensive for almost thirty years, electricity's convenience eventually won it prominence in the lighting market.

Electrical innovations in late 19th century America sparked not only a technological transformation but a business revolution as well. For example, the average incandescent bulb which lasted only 400 hours in 1883 would triple its durability only two years later.<sup>2</sup> Its success created the inducement for numerous entrepreneurs to manufacture the lamps and generators

---

<sup>1</sup> Richard Munson, *The Power Makers* (Emmaus, PA: Rodale Press, 1985), 48.

<sup>2</sup> *Ibid.*, 52.

needed to power them. Within a decade of their introduction, incandescent lamps lit more than 1.3 million homes and offices throughout the United States.<sup>3</sup>

Such innovations created chaos as well as opportunity. Totally unique electrical arrangements overlapped each other. In Philadelphia alone, more than twenty electric power systems operated based on different patents by Edison, Sawyer, Maxim, Westinghouse, Brush, among others.<sup>4</sup> Twenty-nine franchises were granted in Chicago, three of which were citywide.<sup>5</sup> Some direct current (DC) companies offered electricity at 100, 110, 220, and 600 volts; alternating current (AC) firms supplied frequencies of 40, 60, 66, 125, and 133 cycles.<sup>6</sup> It was said that a customer moving across the street would often find that none of his electrical appliances worked in the new home.

In an attempt to protect themselves from "ruinous competition," electric utility executives initially tried to fix prices and production levels. These secret efforts were eventually denounced by the public and rendered illegal by the Sherman Antitrust Act of 1890.

A more practical step was to merge or consolidate. George Westinghouse built his electric company by acquiring other people's patents rather than developing his own inventions. After purchasing the United States Electric Lighting Company (which owned the then important Maxim and Sawyer lamp patents), Westinghouse even contemplated cooperation with Edison. But Edison would have no part of sharing his business with a rival.

It was J. P. Morgan who envisioned the largest merger. Having gained effective control of the Edison General Electric Company, Morgan met with Charles Coffin, president of the Thompson-Houston Electric company. Coffin, like Westinghouse, had purchased patent rights and named his company after the Philadelphia professors who developed them. Coffin expanded Thompson-Houston's business and increased its value beyond that of Edison General Electric by

---

<sup>3</sup> Ibid.

<sup>4</sup> Ibid.

<sup>5</sup> Leonard S. Hyman, *America's Electric Utilities: Past, Present, and Future* (Arlington, VA: Public Utilities Reports, Inc., 1988), 64.

<sup>6</sup> Munson, *The Power Makers*, 52.



offering easy credit and by accepting the securities of local electric companies. The merger of these two companies made both financial and technological sense because they possessed complementary patent holdings: Edison General Electric dominated urban DC stations, DC power transmission and street railways, while Thompson-Houston's forte lay in arc lighting and alternating currents.<sup>7</sup>

Despite the bounding engineering advances and optimistic predictions, producing and delivering electricity remained an infant struggling industry at the turn of the century. Electric motors powered only one factory in thirteen while incandescent bulbs illuminated one lamp in twenty.<sup>8</sup>

Prospects for growth remained uncertain. Factory owners were reluctant to displace their steam-powered, belt-driven systems with still-unreliable electric motors. Most consumers initially favored the less expensive light supplied by gas lamps. Even electric company executives believed electricity would remain a luxury good without a mass market. Quickly adding new customers required construction of expensive distribution systems, which for a time increased the cost of power and decreased the power company's profits. The favored strategy in the early days was to grow slowly by encouraging a small number of customers to buy more power at progressively lower rates.

At that time, "smart" money favored isolated plants over central power stations. Coaxed by J. P. Morgan and other financiers, the new General Electric Company promoted small-scale systems. These systems could be mass-produced and sold at a substantial profit to factories and office buildings. At the same time, General Electric charged inflated prices for its central station equipment to combat competition from emerging electric companies for its small systems market. As a result, when Edison's former personal secretary, Samuel Insull, left to manage the Chicago Edison Company in 1892, small-scale systems were the dominant suppliers in the United States. On-site generators such as streetcar companies, commercial building managers, and industrialists

---

<sup>7</sup> Ibid., 53.

<sup>8</sup> Ibid., 55.

supplied almost two-thirds of the nation's electricity.<sup>9</sup>

In addition to competing with isolated electric plants, belt-driven motors, and gas lamps, electric companies vied with each other. Unlike today's electric utilities, generating firms did not possess monopoly control over a specific region. For example, the Denver Common Council granted franchises "to all comers" as long as the companies did not block public streets.<sup>10</sup> Forty-seven generating companies competed in Chicago alone.<sup>11</sup>

Although these electric empires were logical outgrowths of emerging technologies, they provoked public mistrust and anger. Exclusive control of a given territory remained Insull's ultimate goal, but he understood the public's mistrust of monopolies. He suggested a bargain: an exclusive franchise in exchange for public regulation. To avoid public takeovers and political headaches, Insull promulgated a plan to establish state regulatory commissions. These commissions were to be staffed with professionals and operated independent of local politics. Not all of his electric company colleagues agreed with this idea, however. Nonetheless, in 1907 progressive governors such as Robert M. La Follette of Wisconsin and Charles Evans Hughes of New York established

---

<sup>9</sup> Ibid., 55.

<sup>10</sup> Ibid., 56.

<sup>11</sup> Ibid.

independent regulatory commissions to oversee electric firms. By the end of World War I, twenty-six states had followed their lead.<sup>12</sup>

These state commissions transformed competitive electricity suppliers into regulated public utilities. To eliminate the clutter and expense of duplicative transmission wires, they gave the new utilities monopoly control of electricity distribution in defined service territories and offered them the ability to obtain economies of scale offered by large power plants. By extending previous Supreme Court decisions affecting railroads, regulators helped to assure electric companies a "fair return" on their investments.

### **The Era of Utility Holding Companies**

The 1920s represented a roller coaster period for the electric industry. New technologies made further expansion possible. Larger and more efficient generators were built and long-distance transmission lines sent power over greater distances. Expansion was also a deliberate attempt to lower costs through economies of scale. Indeed, the cost of a kilowatthour from a central power station dropped from 22 cents in 1892 to 7 cents three decades later.<sup>13</sup>

The industry also saw the massive merging of small operating utilities into a few large holding companies. Some analysts attributed this restructuring to the potential scale and coordination economies that could be realized by the formation of large electric power systems under the umbrella of a single corporate entity. Studies conducted in the early 1920s showed that significant scale economies could result from further interconnections of existing electric power systems.<sup>14</sup>

---

<sup>12</sup> Ibid., 62.

<sup>13</sup> Ibid., 56.

<sup>14</sup> It was widely recognized in the 1920s and 1930s that large integrated networks were the most economical form of utility structure. Many of the mergers during the 1920s involved the integration of several small operating companies into large holding companies. See William J. Hausman and John L. Neufeld, "Public Policy and the Structure of the Electric Power Industry: Lessons from the Past," presented at the 23rd Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 10, 1991.

The 1920s was a period of dramatic growth in demand for electricity. As the industry looked for ways to attract new capital, it increasingly looked to a holding-company structure. One author calculated that electric utilities spent more money during the 1920s than the transcontinental railroads during the era of their most rapid expansion.<sup>15</sup> By 1932 about half of the privately owned electric industry was controlled by three "super" holding companies.<sup>16</sup> By 1938 when PUHCA was first enforced, there were 214 registered holding companies.<sup>17</sup>

Holding companies were successful in acquiring new capital and achieving integration economies, but they engaged in various abuses. At the request of Congress, the Federal Trade Commission (FTC) conducted a large-scale study on the "complex and shadowy" accounting and financial practices of utility holding companies. In a report issued in 1935, the FTC documented holding-company abuses starting in the 1920s.<sup>18</sup>

The most noteworthy alleged abuses included "pyramiding" of corporate structure that allowed large amounts of operating company assets to be controlled by those with small investments; issuing securities affecting subsidiaries without state approval; abusive self-dealing in which subsidiaries pay inflated prices for services, materials, and equipment; shifting costs among subsidiaries located in different states; and excessive leveraging of debt. The FTC report did concede that "under holding companies [electric] service was improved and extended, consumption increased, and costs of production were reduced."<sup>19</sup>

---

<sup>15</sup> Thomas Hughes, *Networks of Power* (Baltimore: Johns Hopkins University Press, 1983).

<sup>16</sup> Douglas W. Hawes, *Utility Holding Companies* (New York: Clark Boardman Company, 1987), 2-5.

<sup>17</sup> *Ibid.*, 2-18.

<sup>18</sup> Federal Trade Commission, *Utility Corporations*, S. Doc. 92, 70th Cong. (1928-1935).

<sup>19</sup> Quoted in Munson, *The Power Makers*, 64.

Even before the FTC report was completed, however, the utility holding companies' house of cards had folded. Successful "customer ownership drives" of Insull had helped the holding companies attract the money needed to acquire other utility properties. Security prices soared but the good times came to a quick halt. On "Black Friday," October 29, 1929, stock prices plummeted. Despite the economy's subsequent collapse, utility stock prices and earnings initially fared better than the rest of the economy. Part of this was attributable to increasing residential demand for electricity, but another part to fraud. The Depression did dry up financial capital needed for capacity expansion, however, forcing holding companies to dramatically extend their borrowings from banks and to juggle funds among their numerous operating companies. As the financial crises of the early 1930s intensified, utility holding companies ultimately failed and the price of their stocks plummeted.

The reported abuses in the 1935 FTC study and large investor losses led to new federal legislation, providing the political ammunition for drastic changes in the structuring of the electric industry. The early 1930's debate over PUHCA occurred at a time when the Roosevelt Administration was pursuing general regulatory reform. For electric utilities change began when Roosevelt signed into law the Rural Electrification Act, which provided low-cost loans to public cooperatives that built their own power lines and generated their own electricity. The "New Dealers" created the Securities and Exchange Commission (SEC) to protect investors against deceptive practices and a series of banking acts to prohibit commercial banks from having investment banking affiliates.

Legislation such as the Federal Power Act, the Natural Gas Act, and the Federal Communications Act all were enacted during the 1930s. These acts, similar to PUHCA, helped to close jurisdictional gaps in regulation. During the 1930s legislation also strengthened the position of public-power entities (for example, the Tennessee Valley Authority and the Bonneville Power Administration), and rural electric cooperatives. The general belief was that privately owned utilities could not be relied upon to ensure the wide distribution of low-priced power, especially to rural areas.

Enacted in 1935 (although not enforced until 1938) PUHCA ushered in two significant changes in the electric industry (see Table 2-1 for the broad SEC regulations

**TABLE 2-1**  
**SEC JURISDICTION OVER UTILITY HOLDING COMPANIES**

<u>Producer</u>	<u>Regulations</u>
<ul style="list-style-type: none"> <li>• Registered utility holding companies</li> </ul>	<ul style="list-style-type: none"> <li>• approval of utility acquisition and vertically nonutility acquisitions</li> <li>• approval of service, sales, and construction contracts and other activities between holding company and affiliates</li> <li>• restriction of acquisitions to utility-related businesses (mostly to facilities integrated with existing utility system)</li> <li>• approval of corporate and financial structures</li> <li>• approval of securities sales</li> </ul>
<ul style="list-style-type: none"> <li>• Exempt utility holding companies</li> </ul>	<ul style="list-style-type: none"> <li>• approval of acquisition of 5 percent or more of another utility's securities</li> <li>• monitoring of activities by reviewing annual SEC filings and industry publications</li> </ul>

Source: Authors' construct.

following PUHCA). First, it gave state public utility commissions the de facto ability to regulate electric utilities as prescribed by state statutes. Prior to the passage of PUHCA, although state commissions may have had jurisdiction over operating electric

companies, no regulatory entity oversaw the activities of highly complex holding companies that controlled and often exploited their operating companies. By simplifying holding companies' corporate and financial structures and by restricting their utility operations to a single geographical area, PUHCA allowed state commissions to regulate more effectively.

Second, PUHCA achieved its objective of restructuring the electric industry. Under its so-called "death clause," the Act eliminated all holding companies that did not operate as an integrated electric power system. As proof, in 1938 there were 214 registered holding companies; by 1955, when the Securities and Exchange Commission had largely completed its job of dissolving and reorganizing the registered holding companies, there were twenty-five registered systems with 171 utility subsidiaries and 137 nonutility subsidiaries; today, the number of registered holding companies is nine.<sup>20</sup> During the first twenty years after the passage of PUHCA, registered holding companies divested themselves of 839 subsidiaries with assets of nearly \$13 billion.<sup>21</sup> Only those holding companies that demonstrated efficient operation of a single, integrated multistate electric power system were left intact.

In sum, PUHCA reorganized the electric industry in a way that allowed regulators to perform their designated task more effectively. The industry today for the most part consists of intrastate utilities owning and controlling functionally and geographically integrated power systems. PUHCA may have constrained the electric industry from structuring more efficiently. In the absence of PUHCA, the electric industry today probably would be less vertically integrated and be less subject to state regulation.

---

<sup>20</sup> These are: Allegheny Power System, American Electric Power Company, Central and South West Corporation, Eastern Utilities Associates, Entergy Corporation, General Public Utilities Corporation, New England Electric System, Northeast Utilities, and the Southern Company. Registered holding companies account for about 25 percent of the electricity generated in the United States.

As of 1991, there were 110 exempt electric utility holding companies. They account for over 50 percent of the electricity generated in the United States. See U.S. General Accounting Office, *Electricity Supply: Regulating Utility Holding Companies in a Changing Electric Industry* (Washington, D.C.: U.S. General Accounting Office, April 1992).

<sup>21</sup> Hawes, *Utility Holding Companies*, 2-18.

## Later Events

The current debate on PUHCA can trace its origins to 1978 and the Public Utilities Regulatory Policies Act (PURPA), which was in part a response to the unstable energy conditions of the 1970s.<sup>22</sup> The electric utility enjoyed a "golden age" in the two decades following World War II, but by the end of the 1970s, events had evidenced an erosion in the electric industry's ability to provide energy efficiently.

First came the Northeast Blackout of 1965, followed by Consolidated Edison's omission of its common stock dividend in April 1974, the accident at Three Mile Island in March 1979, as well as the construction cost overruns, prudence reviews, and abandonments of nuclear plants in the 1980s. The problems raised by the inflation of the 1970s and later the increasingly costly safety changes required in the wake of TMI created a quandary for legislators and regulators. One response was to mandate incentives for cogeneration and small power production.

As nonutility power producers began to increase in number and compete with (not merely supplement) established integrated electric utilities, transmission access grew as an important issue. Congress first considered provisions for expanding transmission access in the debate over PURPA and again when it passed the Electric Consumers Protection Act in 1986. But these provisions were never included in the legislation. Power "shortages" during the summer of 1988 refocused attention on the need for additional generation in some parts of the country. The debate in Congress over how to "fix" the industry and whether amending PUHCA was part of that solution dragged on over the next four years. Recent events, however, galvanized Congress' determination to produce some sort of comprehensive energy legislation which included amending PUHCA. The United States' involvement in the 1990-91 Gulf War appeared to some critics to be triggered by a national energy strategy of "import oil." Fearing that an anti-

---

<sup>22</sup> As a factual observation, the SEC in the early 1980s urged the repeal of PUHCA on grounds that the Act had achieved its purpose and was no longer necessary.



incumbent whiplash would result from a perceived failure to enact some sort of comprehensive legislation, Congressional leaders pushed the PUHCA debate on through 1992. When the electric utility industry began to split over the status of PUHCA, the prospects for amendment grew significantly.

## CHAPTER 3

### POWER GENERATORS IN THE ELECTRIC INDUSTRY

#### Recent Changes

Passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) initiated a series of events that reshaped the structure of the electric industry. A changing perception induced in part by PURPA's success was that smaller-scale generating facilities owned and operated by nonutilities could provide the nation with an economical source of new capacity.<sup>1</sup>

During the past decade PURPA-qualifying facilities have produced over 31,000 megawatts of generating capacity, or about 25 percent of new capacity.<sup>2</sup> The U.S. Department of Energy and others predict that the country will require an additional 100,000 to 150,000 megawatts of new generating capacity by the year 2000.<sup>3</sup> Assuming a new PUHCA and the elimination of other major barriers to independent power generation, as much as 50 percent of this new capacity may come from nonutilities.<sup>4</sup>

Electricity markets increasingly gravitate toward smaller generating facilities, in part

---

<sup>1</sup> See, for example, Paul L. Joskow, "Expanding Competitive Opportunities in Electricity Generation," *Regulation* (Winter 1992): 25-37; and Council of Economic Advisors, *Economic Report of the President* (Washington, D.C.: U.S. Government Printing Office, February 1992), 178-80.

<sup>2</sup> "Consensus Reached Among Diverse Group of Electric Power Suppliers and Consumers for PUHCA Amendment," NARUC No. 40-1990, (Washington, D.C.: National Association of Regulatory Utility Commissioners, October 1, 1990), 20.

<sup>3</sup> Ibid.

<sup>4</sup> See, for example, Jerry L. Pfeffer, "'Megatrends' in the Electric Power Industry: Toward the Year 2000," presented at Electric Utility Business Environment Conference, Denver, Colorado, March 18, 1992; and "EEI Sees No Shortages, Increasing Reliance on DSM Programs and NUGs," *Electric Utility Week* (December 9, 1991): 7-8.

One example of a major barrier is obstructions to widespread transmission access. Other barriers are discussed in Chapter 6.

because of lower load growth and the increasing uncertainties over future electricity demand and construction costs for large generating facilities. By allowing producers more flexibility, small facilities diminish the risks of unexpected events. Smaller-scale generating facilities also have benefitted from recent technological advancements. Until recently, technological advances in the electric industry have disproportionately benefitted large-scale facilities.<sup>5</sup>

The trend in the electric industry toward smaller and less capital-intensive generating facilities with shorter construction lead times reflects a rational response to economic realities. The dismal record of electric utilities building new nuclear power plants during the 1970s and 1980s points to the risks associated with power plants large in scale but apparently immature in technology.<sup>6</sup> Further, it illustrates the increased incentive for participants to restructure the electric industry so smaller-scale facilities can compete more equally with other generating facilities. The recent popularity of state-approved power procurement and least-cost energy planning mechanisms partially exemplifies the state regulators' perception of the potentially high risks associated with large-scale generating facilities.<sup>7</sup>

Other factors have also contributed to the current push toward restructuring the electric industry. Charles Stalton and Reinier Lock point to the changed macroeconomic and energy-market conditions (for example, high interest and inflation rates, stagnant technological advancements, and volatile fuel prices) beginning during the 1970s which rate-of-return regulation

---

<sup>5</sup> See Paul L. Joskow and Richard Schmalensee, *Markets for Power: An Analysis of Electric Utility Deregulation* (Cambridge, MA: The MIT Press, 1983).

<sup>6</sup> See Martin B. Zimmerman, "Learning Effects and the Commercialization of New Energy Technologies: the Case of Nuclear Power," *The Bell Journal of Economics* 13 no. 2 (Autumn 1982): 297-310. Zimmerman blames the lack of understanding of the basic nuclear-power technology as a major reason for the problems experienced by the utility industry during the 1970s.

<sup>7</sup> The popularity of power procurement mechanisms is demonstrated in Kenneth Rose, Robert E. Burns, and Mark Eifert, *Implementing a Competitive Bidding Program for Electric Power Supply* (Columbus, OH: The National Regulatory Research Institute, 1991).

poorly addressed.<sup>8</sup> When utility costs started to rise sharply and quickly, regulators were faced with either allowing utilities to fully recover their increased costs at the disdain of ratepayers or not allowing full recovery, which would jeopardize a utility's financial position. While regulators searched hard to balance the interests of ratepayers and utility shareholders, they faced a "Catch-22" situation over which they had little control. The fallout that resulted caused ratepayers and utilities alike to be skeptical of the prevailing order. The general public through their political representatives increasingly began to believe that more competition could help control electricity prices while utilities questioned whether there was an easier way to make profits (for example, by repositioning their assets to serve markets subject to less stringent regulation). Both groups started to accept the idea that restructuring of the electric industry would be a potentially acceptable alternative to the status quo.<sup>9</sup>

### **Different Power Generators**

Table 3-1 lists the commonly identified categories of power generators currently operating in the electric industry. (See Table 3-2 for attributes of each major class of

---

<sup>8</sup> Charles G. Stalon and Reinier H. J. H. Lock, "State-Federal Relations in the Economic Regulation of Energy," *Yale Journal on Regulation* 7 no. 2 (Summer 1990): 427-97.

<sup>9</sup> Another way of expressing this thought, according to the economic theory of regulation, is that restructuring will occur whenever changes either in political power or market conditions dissipate much of the benefits of the status quo to market participants. See Sam Peltzman, "The Economic Theory of Regulation after a Decade of Deregulation," Martin Neil Baily and Clifford Winston, eds., *Brookings Papers on Economic Activity: Microeconomics 1989* (Washington, D.C.: The Brookings Institution, 1989), 1-59.

**TABLE 3-1**  
**DIFFERENT CATEGORIES OF POWER GENERATORS**

---

Total Generators (TG) = Nonutility Generator (NUGs) +  
Rate Based Generators (RBGs)

where

NUGs = Qualifying Facilities (QFs) +  
Nonqualifying Facilities (NQFs)

where

QFs = Cogenerators (CGs) + Small Power  
Producers (SPPs)

and

NQFs = True Independent Generators (TIGs) +  
Utility Affiliated Generators (UAGs)

---

Source: Authors' construct.

**TABLE 3-2**  
**CHARACTERISTICS OF DIFFERENT POWER GENERATORS**

Power Generator	Pricing (jurisdictional regulator)	Comments
<ul style="list-style-type: none"> <li>• PURPA Qualifying Facilities (QFs)</li> </ul>	<ul style="list-style-type: none"> <li>• Avoided cost (PUCs)</li> <li>• Competitive bidding price (PUCs)</li> </ul>	<ul style="list-style-type: none"> <li>• Exempt from PUHCA (not greater than 30 megawatts)</li> <li>• Guaranteed market and price</li> <li>• 50 percent utility ownership limit</li> <li>• Power predominantly for local sale or internal, on-site use</li> </ul>
<ul style="list-style-type: none"> <li>• True Independent Generators (TIGs)</li> </ul>	<ul style="list-style-type: none"> <li>• Market based (FERC)</li> </ul>	<ul style="list-style-type: none"> <li>• Nonexempt from PUHCA</li> <li>• Competes with other wholesale suppliers</li> <li>• No limit on utility ownership</li> <li>• Little chance of market power</li> </ul>
<ul style="list-style-type: none"> <li>• Utility Affiliated Generators (UAGs)</li> </ul>	<ul style="list-style-type: none"> <li>• Cost of service (FERC)</li> <li>• Market based (FERC)</li> </ul>	<ul style="list-style-type: none"> <li>• Nonexempt from PUHCA</li> <li>• Competes with other wholesale suppliers</li> <li>• No limit on utility ownership</li> <li>• Potential problem of market power</li> </ul>
<ul style="list-style-type: none"> <li>• Rate Based Generators</li> </ul>	<ul style="list-style-type: none"> <li>• Cost of service (PUCs)</li> <li>• Cost of service (FERC)</li> </ul>	<ul style="list-style-type: none"> <li>• Spinoffs nonexempt from PUHCA</li> <li>• Subject to traditional regulation</li> <li>• Exclusively utility owners</li> <li>• Power primarily sold to retail customers under traditional ratemaking</li> </ul>

---

Source: Authors' construct.

power generator).<sup>10</sup> Generators consist of two general types, ratebased generators and nonutility generators. Ratebased generators (RBGs) produce most of their power for wholesale requirements and retail consumers.<sup>11</sup> They are subject to either state or federal regulation and their costs generally are recoverable from customers by cost-of-service ratemaking.<sup>12</sup>

Nonutility generators include PURPA-qualifying facilities (QFs) and nonqualifying facilities (NQFs). Power produced from PURPA-qualifying facilities, namely cogenerators (CGs) and small power producers (SPPs), is typically priced on the basis of the local utility's avoided cost. All available power produced by QFs must be purchased by the local utility.

Nonqualifying facilities, in contrast, have no guaranteed market; they must sell their power at a price competitive with other options accessible to a utility and other buyers. The price received by NQFs is based either on market conditions or the producer's cost of service.<sup>13</sup>

Nonqualifying facilities include true independent generators (TIGs) and utility affiliated generators (UAFs). The essential difference between the two generators lies in their potential to exercise market power. True independents by definition have no retail franchises, no affiliation with vertically integrated utilities, and no transmission facilities. Their profits and survival potential depend on their ability to provide wholesale markets with competitively priced, highly

---

<sup>10</sup> A similar breakdown of power generators is presented in Bernard W. Tenenbaum and J. Stephen Henderson, "Market-Based Pricing of Wholesale Electric Services," *The Electricity Journal* 4 no. 10 (December 1991), 42.

<sup>11</sup> Wholesale requirements buyers usually are utilities that own little or no generating capacity. They most frequently are either municipalities or rural electric cooperatives located within the control area of the selling utility.

<sup>12</sup> A portion of many ratebased facilities is used to sell coordination power in wholesale markets. A utility selling such power has temporary surplus capacity that can be used to generate power for other than native-load customers. In most circumstances, FERC allows the transactors of coordination power to negotiate a mutually agreed price and other terms and conditions (assuming that market power is not a problem). A commonly used pricing practice for transactions is the "split-the-savings" approach (that is, price is set halfway between the seller's incremental cost and the buyer's avoided cost).

<sup>13</sup> As discussed later, the pricing method allowed by FERC depends on the degree of market power that is assumed to be held by a producer.



reliable power.<sup>14</sup> Power production from nonqualifying facilities currently is small. For example, only five such facilities were operating in 1991.<sup>15</sup>

Affiliated generators represent less of an opportunity to foster competition, contingent upon their ability and incentive to self-deal with a parent company that controls transmission lines and serves core retail ratepayers. The category "nonqualifying facilities" (assuming that they sell only to wholesale consumers) is identical to the meaning of "exempt wholesale generators" (EWGs) in the recently passed Senate energy legislation.<sup>16</sup> Currently, most of the power produced from nonutility generators comes from PURPA-qualifying facilities. An expected and supposedly desirable outcome of PUHCA amendments would be a shifting of nonutility power production from PURPA-qualifying facilities to nonqualifying facilities. Federal regulations exempt most PURPA-qualifying facilities from PUHCA.<sup>17</sup>

---

<sup>14</sup> With the emergence of nondiscriminatory transmission access, independent power producers may not require long-term power contracts to enter the marketplace. Open transmission access may create an environment for a highly developed spot market for power while at the same time it may increase the costs to both producers and buyers of limiting themselves to long-term contracts.

It is questionable how purchased power contracts over the next few years will allocate risks between independent power producers and utility buyers. Passing all of the risk onto the producers, while protecting utility ratepayers, may jeopardize the financial viability of the independent power industry in the long run. At the other end, state regulators and bond rating agencies have expressed some concern that independent producers and lenders have successfully transferred risks back to utilities and their ratepayers. For example, many existing long-term purchased power contracts between a nonutility generator and a utility contain "minimum take" provisions and fuel price indexation clauses that pass most fuel-price risk to the utility. See Edward P. Kahn, "Risks in Independent Power Contracts: An Empirical Survey," *The Electricity Journal* 4 no. 9 (November 1991): 30-45.

<sup>15</sup> U.S. General Accounting Office, *Electricity Supply: Regulating Utility Holding Companies in a Changing Electric Industry* (Washington, D.C.: U.S. General Accounting Office, April 1992), 5.

<sup>16</sup> In the House bill these generators are called "independent power producers," who operate facilities that generate power exclusively for wholesale markets as well.

<sup>17</sup> FERC has exercised its authority under section 210(e) of the Public Utility Regulatory Act of 1978 (PURPA) to exempt cogenerators and small power producers of 30 megawatts or less as well as producers of 80 megawatts or less using biomass as the primary fuel (45 *Federal Register*

## How a New PUHCA Would Affect Different Power Generators

PUHCA has discouraged the formation of wholesale power facilities that do not qualify under PURPA. Wholesale power facilities are defined as "electric utilities" under PUHCA and generally are financed under a holding company structure.<sup>18</sup> Both utilities and nonutilities wanting an interest in such facilities, consequently, are restricted by PUHCA (see Table 3-3).<sup>19</sup>

PUHCA generally has precluded both registered and exempt holding companies from having an interest (ownership or operation) in wholesale power facilities located in states outside their franchised service area. As a general rule, the SEC would only approve acquisitions of those facilities integrated with existing utility operations and confined to a single area. Exempt holding companies would retain their status only when they acquire a wholesale facility that integrates with their existing intrastate utility operation or when the utility business functionally relates to the nonutility business and represents a small part of the holding company's income.<sup>20</sup> The SEC also may approve

---

12214, 12232-12233 (February 25, 1980)).

<sup>18</sup> By forming a separate subsidiary, rather than a separate division, the owner avoids liability for its existing businesses. As utilities they also would favor forming a subsidiary to prevent regulators from transferring profits to ratepayers in the form of lower rates.

<sup>19</sup> Any legal entity becomes a utility holding company when it gains control of 10 percent or more of an electric or gas utility (Public Utility Holding Company Act, section 2(a)(3).)

<sup>20</sup> See, for example, Public Utility Holding Company Act, section 3(a)(3) (the "only incidentally holding companies" exemption).

**TABLE 3-3**  
**PUHCA RESTRICTIONS ON FORMING WHOLESALE POWER FACILITIES**

Entity	Current Restriction
Registered Holding Companies:	Mainly prohibited, unless wholesale power subsidiary integrated with existing utility system*
Exempt Holding Companies:	Limited to geographical area of affiliated operating utilities or else either may lose exemption status or be prohibited
Operating Utilities:	Status of utilities changed to utility holding company (exempt or registered) subject to SEC regulations
Nonutility Firms:	Controlling interests defined as utility holding companies (exempt or registered) subject to SEC regulations
PURPA Qualifying Facilities:	None (for QFs not greater than 30 megawatts)

Source: Authors' construct.

\* This assumes that the holding company gains control of 10 percent or more of the voting securities.

an acquisition when the holding company is predominantly a utility whose operations are wholly within one state or in contiguous states.<sup>21</sup>

---

<sup>21</sup> Public Utility Holding Company Act, section 3(a)(1) (the "predominantly intrastate" exemption). The vast majority of the 110 exempt utility holding companies qualify under this section of the Act.

An operating utility that falls outside a holding-company structure also confronts restrictions in having interest in a wholesale power facility. It would be subject to SEC regulations as a newly formed utility holding company, thereby restricted from forming wholesale facilities in different areas unless integrated as a single utility operation.

Nonutility firms such as engineering firms and construction companies would become utility holding companies any time they have an interest in a wholesale power facility. This would limit both their development of wholesale facilities to one area and their diversification into other nonutility businesses. In the case where they would not receive exempt holding company status from the SEC, they would be required to divest nonutility activities.<sup>22</sup>

Most PURPA-qualifying facilities are exempt from PUHCA. Utilities (including utility holding companies), however, generally are limited to 50 percent ownership interest in such facilities.<sup>23</sup> PURPA explicitly says that an entity (for example, an electric utility or its affiliates) cannot own a qualifying facility that is "primarily engaged" in the sale or generation of electricity. In rules adopted in 1980, FERC interpreted the term "owned" to mean having more than a 50 percent equity interest in a qualifying facility. FERC has broadly interpreted "primarily engaged" as "any person. . .which sells electric energy [other than electric energy from QFs]." This person would be considered an "electric utility" under PURPA and therefore limited to 50 percent ownership of a qualifying facility. FERC, however, has allowed exceptions to this rule where an entity received an exemption from PUHCA as being "not primarily engaged in electric power generation or sales."

The new PUHCA would eliminate SEC oversight of both utilities and nonutility firms acquiring wholesale power facilities. It would end the advantage currently given to most PURPA qualifying facilities because of their exemption from PUHCA. For example, utility holding companies and operating utilities can have an interest in PURPA qualifying facilities without regard to their geographical location. The substantial capital and entrepreneurial efforts that have

---

<sup>22</sup> The SEC has required that a nonutility in seeking an exemption under section 3(a)(3) of PUHCA must not only show that it is primarily engaged in nonutility business (for example, it receives less than 10 percent of its revenues from utility operations) but also that the utility business is "functionally related" to the nonutility business.

<sup>23</sup> For example, FERC has on occasion allowed exceptions to the 50 percent rule when an entity previously obtained an exemption from the SEC as being "not primarily engaged in electric power generation or sales."

gone into cogeneration may have otherwise been diverted to other, more efficient, generation facilities if all wholesale operations were considered equal in the eyes of PUHCA. On the other hand, it can be argued that the 50 percent utility ownership limitation applied to PURPA qualifying facilities has likely discouraged some development of these facilities. It seems that with a new PUHCA, nonqualifying facilities will have an advantage because of the ownership restrictions on qualifying facilities, assuming other things are equal. Other things often are not equal, however; for example, PURPA bestows favors on qualifying facilities unavailable to other facilities--most importantly, it assures a market for qualifying facilities. Other wholesale power facilities do not have such a luxury; they must participate with other producers in a marketplace that has become more competitive.

A new PUHCA also *may* allow utilities to spin off ratebased facilities as exempt wholesale facilities.<sup>24</sup> Utilities may see more future profits coming from existing facilities that are subject to FERC regulation than state regulation. Especially if the spun-off facility receives FERC approval for charging market-based prices, utilities may find it more lucrative to dedicate some of their existing facilities to wholesale markets. This would especially be true for depreciated facilities earning the utility small returns.<sup>25</sup> In such a situation, where the book cost of a facility lies below the market value, a utility would have the incentive to transfer the facility to a market-priced regime. The problem for retail customers is that they would lose the benefits of low-cost electricity which they in effect previously paid for during the earlier years of the facility's life.

---

<sup>24</sup> As noted later, the House bill would prohibit such activities by excluding existing ratebased facilities from eligibility as exempt facilities.

<sup>25</sup> Dedicating existing facilities to wholesale markets would mean that these facilities would no longer be ratebased and subject to state regulation. A utility would favor such action when it expects to earn a higher profit (adjusted for risk) from selling in the more competitive wholesale markets than from selling directly to retail customers under cost-of-service regulation. Although the price for power generated by dedicated wholesale facilities would be regulated by FERC, none of the seller's profits would be distributed to retail customers. This is because these customers are no longer paying any of the costs associated with the dedicated facilities. From a social perspective dedication may be attractive since the seller would have a strong incentive to sell power anytime it receives a price greater than its marginal cost as well as to minimize its cost of operation. The second incentive assumes that the price is divorced from the seller's cost of service (for example, FERC allows market-based prices).

## CHAPTER 4

### THE IMPLICATIONS OF A NEW PUHCA FOR RETAIL CONSUMERS

A more lenient PUHCA would ease the entry of new generators into the electric industry. Nonutility and utility entities alike would have the freedom to own interests in wholesale power facilities in different parts of the country without the restrictions of PUHCA. Wholesale power producers, including utility affiliates, currently could avoid all SEC regulations under PUHCA, for example, by shifting their roles from a general partner during financing and construction to a limited partner when plant operations begin. One problem with this approach revolves around choosing a general partner who is competent and trustworthy. Another option is for no partner to have more than a 10 percent voting interest in a facility.<sup>1</sup>

Assuming that the current PUHCA has discouraged the entry of wholesale power producers, utilities would have more options from which to choose to satisfy their future demand needs. New supply sources, by and of themselves, should give utilities the opportunity to lower their future costs. As a matter of practice, however, the possibility for anticompetitive actions by utilities makes it less than certain that a new PUHCA would benefit retail consumers.<sup>2</sup>

Both FERC and state public utility commissions would play important roles in affecting the benefits to retail consumers. FERC would face more requests from wholesale producers to approve market-based rates. The ability of FERC to allow such

---

<sup>1</sup> Options to avoid becoming a holding company are discussed in Kenneth Rose, Robert E. Burns, and Mark Eifert, *Implementing a Competitive Bidding Program for Electric Power Supply* (Columbus, OH: The National Regulatory Research Institute, 1991), 86-88. The authors distinguish these options from those that allow a holding company to qualify as an exempt holding company.

<sup>2</sup> As discussed later, these actions include self-dealing abuses, cross-subsidization, and collusive arrangements among utilities.

rates only for those transactions consummated under workably competitive conditions will influence the benefits to retail consumers.<sup>3</sup>

At the state level, commissions would have to determine with greater frequency whether long-term wholesale purchases by jurisdictional utilities represent least-cost resource options. Utilities should have available more resource options from which to choose. They, as well as their regulators, must decide whether these new available resources represent least-cost options. Faced with the prospect of increased requests for self-dealing transactions, commissions would have to devote greater time and effort to assuring that such transactions do not entail an abusive arrangement.<sup>4</sup> Greater numbers of utilities also would likely request approval to form subsidiaries and spin off existing generating facilities as exempt wholesale generators. Under the Senate bill, spinoffs of facilities by utility holding companies and operating utilities will require approval from state commissions, or, for existing affiliates of registered holding companies, from the SEC. Commissions, in response, must examine the effects these actions will have on retail consumers. For example, allowing the formation of subsidiaries may impose risks that would increase the utility's cost of capital and improperly shift costs to the utility's operating company.<sup>5</sup> The entry of new wholesale producers enhances the economic

---

<sup>3</sup> FERC is likely to adopt generic rules during the next several months on eligibility for market-based pricing by wholesale power producers. Past criteria used by FERC on a case-by-case basis for the acceptability of market-based pricing are discussed in Bernard W. Tenenbaum and J. Stephen Henderson, "Market-Based Pricing of Wholesale Electric Services," *The Electricity Journal* 4 no. 10 (December 1991): 30-45. It is expected that the rules will follow closely the criteria applied by FERC in recent decisions.

<sup>4</sup> This assumes that the states have the authority and are willing to allow self-dealing transactions involving exempt wholesale power producers.

<sup>5</sup> These risks are discussed in detail in Robert E. Burns et al., *Regulating Electric Utilities with Subsidiaries* (Columbus, OH: The National Regulatory Research Institute, 1986). Although the study showed that the vast majority of states have procedures in place directed at mitigating these risks, their ability to do so remains doubtful. For example, the study concluded that:

A particularly difficult common cost allocation problem faced by commissions is to distinguish an operating utility's cost of capital from that of its subsidiaries. When an electric utility has subsidiaries or is itself owned by a parent company, its capital is likely to be intermingled with the capital of the other entities (p. v).

performance of the electric industry only when these producers can generate electricity at a lower cost. This means producers are able to outperform other producers such as vertically integrated utilities and PURPA qualifying facilities. Reasons for this include lower construction and fuel costs, the adoption of more economical technologies, and plants operating at higher technical efficiencies.<sup>6</sup> By producing at lower cost, new entrants can pressure other producers to act more efficiently. Wholesale buyers therefore would have access to lower-cost power, which presumably would flow through to retail consumers in the form of lower rates.

The potential for retail consumers to benefit from the entry of new producers does not necessarily imply this will happen. The outcome will depend in part on the success of regulators in protecting consumers from the possibility of abusive dealings and other actions between exempt wholesale generators and affiliated utilities. Potential abuses resulting from self-dealing, cross-subsidization, and spinning off existing low-cost facilities loom as real risks that could undermine the benefits of a new PUHCA for retail consumers. Whether commissions would be able to protect retail consumers against these practices represents a major challenge.<sup>7</sup>

---

<sup>6</sup> See, for example, Roger F. Naill and William C. Dudley, "IPP Leveraged Financing: Unfair Advantage?" *Public Utilities Fortnightly* (January 15, 1992): 15-18. The authors present persuasive reasons for why independent power producers would be expected to perform better than tightly regulated utilities. They argue that independents need to control their costs to win contracts and make profits. As an illustration, independents have an incentive to achieve higher plant availability since their profits would increase; for regulated utilities, higher plant availability usually means lower rates but not higher profits.

<sup>7</sup> See, for example, Burns et al., *Regulating Electric Utilities with Subsidiaries*; and U.S. General Accounting Office, *Electric Supply: Potential Effects of Amending the Public Utility Holding Company Act*. The GAO study concluded that states have considerable experience in monitoring and regulating utilities' wholesale power transactions. For example, most states have procedures to prevent utility holding companies from allocating improper expenses to a utility subsidiary. Most states have, in addition, the authority to regulate power-plant spinoffs to a nonutility subsidiary.



A new PUHCA likely would increase the pressure for open transmission access to wholesale power producers.<sup>8</sup> New producers, whether independent or utility affiliated, would seek to broaden the markets for their power. They would request transmission system owners to transport their power to those buyers willing to give the most favorable terms. In sum, independents would be expected to make unilateral petitions for gaining transmission access.

Utility affiliates would also benefit from open transmission access; in exchange for this right, their parent companies may reciprocate by providing more liberalized transmission access to other utilities and affiliates.<sup>9</sup> Although there is some question of whether retail consumers would benefit immediately from increased wholesale transmission, it is likely that in the long term they would.<sup>10</sup> With utility buyers having more choices over sources of firm power in addition to the expected increase in competition in wholesale markets, their revenue requirements should fall below what they otherwise would be.

Benefits of a new PUHCA to retail consumers would depend both on the performance of additional wholesale power producers drawn into the marketplace and on the actions of FERC and state commissions (see Table 4-1). A world in which

---

<sup>8</sup> There seems to be a growing consensus that open transmission access will become a reality by the end of this decade through a combination of voluntary utility actions, FERC initiatives and incentives, antitrust lawsuits, and new legislation. See Jerry L. Pfeffer, "'Megatrends' in the Electric Power Industry: Toward the Year 2000" presented at Electric Utility Business Environment Conference, Denver, Colorado, March 18, 1992.

<sup>9</sup> In a similar vein, some utilities have "bargained" with FERC for the opportunity to sell wholesale power at market-based prices in return for more open access to their transmission systems. For example, Public Service of Indiana recently received approval from FERC to price 450 megawatts of wholesale power at market prices in return for granting both utility and independent suppliers greater access to its transmission system.

<sup>10</sup> Retail consumers may suffer in the near term. For example, giving wheeling priority to third parties over economy purchases may harm native-load customers. This would happen when the lost savings from foregone economy purchases exceed the transmission revenues paid by third parties that are returned to native-load customers.

**TABLE 4-1**

**FACTORS OF BENEFITS TO RETAIL CONSUMERS**

---

1. The entry of low-cost wholesale power producers
  2. Competitiveness of wholesale power with other resource options available to utility buyers
  3. Ability of FERC to approve "just and reasonable" wholesale rates
  4. Ability of commissions to approve least-cost wholesale power purchases
  5. Enhanced pressure to liberalize transmission access sales for wholesale producers
- 

Source: Authors' construct.

regulators are successful in preventing anticompetitive actions and new independent power producers are highly efficient would likely produce large benefits to retail consumers. On the other hand, the converse of these conditions would produce minimal benefits or, more unlikely, impose a cost on retail consumers.

## CHAPTER 5

### THE MAJOR COMPONENTS OF A NEW PUHCA

Major changes to PUHCA would facilitate the entry of power producers in wholesale markets. PUHCA restrictions have deterred and severely limited, in the case of some holding companies, the formation of wholesale power subsidiaries.<sup>1</sup> Nonutility and utility affiliated firms currently are constrained by PUHCA to locate new facilities in geographically dispersed areas. For example, in owning a wholesale power facility, a nonutility entity such as an industrial firm would be classified as a utility under PUHCA and thereby become subject to SEC regulations. If the entity fails to receive an exempt status, it would be required to divest its nonutility assets.<sup>2</sup>

Although no final bill has yet been enacted into law, certain components at this time appear likely. They include:

1. formation of a new generator class to be exempt from PUHCA;
2. continued SEC authority over existing affiliates of registered holding companies;
3. continued SEC authority over financing and other activities between registered holding companies and affiliates;
4. plenary SEC authority over power transactions between affiliates of registered holding companies, excluding purchases by affiliates from exempt generators;

---

<sup>1</sup> While the current PUHCA undoubtedly has inhibited the development of independent power production, it is uncertain how much. One view is that independents are waiting for more favorable pricing practices by FERC and easier transmission access before embarking in the wholesale power business. If this is true, the stifling effect of PUHCA per se may not be as significant as many people believe.

<sup>2</sup> Recall, the SEC has required nonutilities seeking exemption status under PUHCA to show that they are primarily involved in nonutility businesses and that the utility business is "functionally related" to the nonutility businesses. Even after gaining exemption, nonutilities would be constrained from owning wholesale power facilities in different geographical areas and in diversifying into nonutility businesses. See U.S. General Accounting Office, *Electricity Supply: Regulating Utility Holding Companies in a Changing Electric Industry* (Washington, D.C.: U.S. General Accounting Office, April 1992), 23.

5. PUC authority over status of existing ratebased facilities subject to state regulation;
6. codification of the Pike County Doctrine (the authority of PUCs to disallow wholesale power costs in the retail costs of the buying utility when lower-cost comparable sources of power were available);<sup>3</sup>
7. prohibition of PUC authority over determining the reasonableness of the selling utility's wholesale power rates approved by FERC; and
8. PUC access to books and records of exempt wholesale generators (EWGs) and affiliated utilities needed to exercise adequately affected commission's authority.

Table 5-1 lists the major components of the Senate bill amending PUHCA. Compared with the PUHCA provisions in the House bill, the Senate version as a whole may be more favorable to state interests.<sup>4</sup> The bill designates a class of power generation, called "exempt wholesale generators (EWGs)," to be exempt from PUHCA. An EWG is defined as an entity in the business of selling electricity exclusively for the wholesale markets. Ownership of EWG is unrestricted meaning utility holding companies, operating utilities, and nonutilities all are able to gain exempt status.

The Senate bill would retain the SEC's broad authority over registered holding companies. For example, the SEC would continue to regulate preexisting affiliates of registered holding companies.

---

<sup>3</sup> For a discussion of the Pike County Doctrine, see William W. Lindsay and Jerry L. Pfeffer, *The Narragansett Doctrine: A 1986 Update* (Columbus, OH: The National Regulatory Research Institute, 1986).

<sup>4</sup> The most important reason is that the Senate bill would codify the Pike County Doctrine while the House bill would not. The Senate bill also places fewer constraints on state commissions, particularly in allowing states more discretion in making decisions on such matters as self-dealing transactions and spinoffs of existing facilities.

**TABLE 5-1**  
**FEATURES OF NEW PUHCA IN SENATE ENERGY BILL**

---

1. Exemption of new wholesale facilities ("exempt wholesale generators" [EWGs]), including those owned by registered holding companies
2. Continued SEC authority over existing affiliates of registered holding company
3. PUC authority over existing facilities subject to state regulation
4. SEC authority over financing and contracts between registered holding company and affiliated EWGs
5. Utility ownership restriction for PURPA-qualifying facilities not affected by ownership in EWGs
6. FERC prohibition of rate approval for sales by EWGs resulting in PUC action disallowing recovery of capital expenses by buying utility for generating facilities under construction or currently receiving a rate of return
7. FERC prohibition of rate approval for EWGs selling directly to either retail customer, nonutility reseller, or any purchaser not using its own transmission or distribution facilities
8. Denial of affiliated transactions involving EWG, unless consented to by all commissions having authority over utility buyer
9. FERC prohibition of rate approval for abusive transactions between EWG and affiliated buyer
10. Prohibition of collusive arrangements among unaffiliated companies
11. Codification of Pike County Doctrine (authority of commissions to disallow wholesale power *costs* in retail rates)
12. Prohibition of PUC authority over reasonableness of wholesale power *rates* approved by FERC (Narragansett Doctrine)
13. Preapproval determination by PUC, at request of utility, of wholesale power costs associated with purchases from EWG; PUC approval binding in absence of new information

---

---

**TABLE 5-1--Continued**

- 
14. Plenary FERC authority over power transactions among affiliates of registered holding company (Mississippi Doctrine), excluding purchases by affiliates from EWG
  15. PUC consideration of long-term wholesale power purchases on utility buyer's cost of capital, retail rates, and reliability; requirement of commission hearing on whether EWGs with less than 35 percent equity have unfair market advantage over self-generation utility
  16. PUC access to books and records of EWG and affiliated utility relevant to exercise of affected commission's authority
- 

The Senate bill would place some restrictions on FERC in approving rates. Rate approval would be disallowed in cases where an EWG transaction would result in a state commission disallowing the recovery of capital costs by the buying utility. The FERC also could not approve rates for affiliated transactions that give an EWG an unfair advantage.

The bill would give state commissions explicit authorities as well as imposes certain restrictions. State commissions would have authority to approve of plant spinoffs to an EWG status,<sup>5</sup> to disallow wholesale power costs in retail rates, and to gain access to the books and records of EWGs and their affiliate utilities. On the other hand, state commissions would be prohibited, as they are now, from rejecting FERC-approved wholesale power rates. States also would be required, in the spirit of Title I of PURPA, to *consider* the effects of wholesale power purchases on the jurisdictional-utility buyer's cost of capital, retail rates, and reliability. Hearings would be required to determine whether EWGs with less than 35 percent equity have an unfair

---

<sup>5</sup> The SEC would continue to have authority over plant spinoffs by existing affiliates of registered holding companies.

advantage over a self-generation utility in meeting the utility's capacity needs.<sup>6</sup> Based on the acquired information, the state would have to determine the appropriateness of adopting capital structure standards within one year after enactment of the bill. Further, at the request of a utility states would have to make a preapproval decision on a proposed transaction with an EWG seller. Cost recovery for approved transactions would be binding on a state commission except when there is "new information which the state commission believes is relevant and material to such cost recovery."<sup>7</sup> Preapproval is a controversial issue that in important ways violates the basic tenets of rate-of-return regulation.<sup>8</sup>

The Senate bill would give the states the right to approve self-deal transactions involving an EWG and an affiliated utility. Finally, the bill would prohibit collusive activities between unaffiliated utilities or their affiliates. Such activities can include

---

<sup>6</sup> The two major arguments in support of this provision were: highly leveraged EWGs pose risk to the buying utility and its customers and they have an unfair financial advantage over utilities who must finance their assets more with higher-cost equity. For a critique of these arguments, see Roger F. Naill and William C. Dudley, "IPP Leveraged Financing: Unfair Advantage?" *Public Utilities Fortnightly* (January 15, 1992): 15-18. See also Laura J. Rittenhouse, "Perceptual Survey of the S&P Purchased Power Credit Risk Policy," *The Electricity Journal* 5 no. 3 (April 1992): 42-52. Some respondents to the survey correctly pointed out that it is not necessarily more risky for utilities to purchase power from third parties than to build new generating facilities. The outcome depends on such factors as the terms of the purchased power contract, the track record of the seller, and its credit status. Importantly, investors of EWGs would pressure operators to fulfill their contractual obligations with utility buyers. Even in the event of a financial failure it is unlikely that power would be unavailable, as owners would want a power plant to continue operating and selling power.

<sup>7</sup> U.S. Senate, "National Energy Security Act of 1992," section 15106, 553.

<sup>8</sup> See, for example, Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992); and Russell J. Profozich et al., *Commission Preapproval of Utility Investments* (Columbus, OH: The National Regulatory Research Institute, 1981).



a secret agreement where each colluding entity would purchase the other's power at an excessive price.<sup>9</sup>

Table 5-2 lists the major unresolved PUHCA issues that will be discussed and debated at the joint House-Senate Conference. The House and Senate bills amending PUHCA contain some major differences. For example, the Senate bill would provide eligible EWGs with a permanent exemption from PUHCA, while under the House bill they would have to receive on a case-by-case basis an exemption from FERC.<sup>10</sup> The House bill would disallow any current ratebased generating facility from receiving an exemption. It also would prohibit all self-dealing transactions involving an exempt wholesale facility.<sup>11</sup>

---

<sup>9</sup> Such reciprocal dealings, when successfully concealed, can be damaging to retail customers and, of course, profitable to the colluding parties. Even without prohibitive legislation, reciprocal dealings may be risky to utilities and, perhaps in some cases, not difficult to detect. A state commission, for example, could determine the reasonableness of prices for individual contracts by comparing them with other prices offered to a utility under a competitive power procurement mechanism, including those rejected by the utility. Commissions could establish other procedures to determine whether certain offers (including those from affiliates) were given preferential treatment. Finally, deterrence would exist because the possibility of a utility "getting caught" may earn the condemnation of its state commission as well as the courts for violating antitrust laws. One problem revolves around the fact that detecting collusive behavior is made difficult by the presence of nonprice contractual provisions. A utility, for example, could argue that although price of power from one source may appear high, the contract allows it more flexibility or provides more highly reliable service. An example of a "daisy chaining" arrangement was the elaborate market allocation schemes, uncovered in 1960, involving electrical equipment manufacturers. See Richard A. Smith, "The Incredible Electrical Conspiracy," *Fortune Magazine* (April 1961): 132-224.

<sup>10</sup> There is some indication that if the House version is passed, FERC would establish a process by which it would grant an exemption and approve market-based prices for EWGs simultaneously. See "FERC Waiting for Final Energy Bill before Issuing Market Pricing Rule," *Electric Utility Week* (June 15, 1992), 5.

<sup>11</sup> Apparently the House considers the risks associated with self-dealing to be significant enough to prohibit all such transactions involving a PUHCA-exempt facility. As a practical matter, the benefits from self-dealing would likely be small: the typical utility should have a number of demand-side and supply side options from which to choose, implying that one less choice would probably have little effect on its costs.

**TABLE 5-2**

**PUHCA ISSUES FOR JOINT HOUSE-SENATE CONFERENCE**

- 
- 
- Exemption process for wholesale power generators
  - Exemption of existing ratebased facilities
  - Self-dealing transactions
  - Restrictions on FERC approval of rates for exempt generators
  - Commission preapproval of purchased power costs
  - Commission consideration of effects of long-term power purchases on utility buyer's cost of capital, rates, and reliability
  - Codification of Pike County Doctrine
- 
- 

A highly important matter for the states is the codification of the Pike County Doctrine; the House bill contains no codification.<sup>12</sup> The Senate bill would require a conditional preapproval

---

<sup>12</sup> The feeling in the House seems to be that states currently have the right to disapprove the costs associated with wholesale power purchases. Consequently, there is no need to legislate a

determination by state commissions of wholesale power transactions between an exempt generator and a jurisdictional utility.<sup>13</sup> Unlike the House bill, the Senate bill also would require states to consider the effects of power purchases on a jurisdictional utility's cost of capital, retail rates, and reliability. State commissions, in addition, would be required to hold a hearing on whether an exempt wholesale generator with less than 35 percent equity financing has an unfair advantage over a self-generation utility.

It is difficult to see the wisdom of this provision in the Senate bill. The fact that a EWG may have less equity financing should in no way imply that its real levelized cost of financing new plant would be lower. The capital markets require EWGs to retain a cash reserve fund and amortize their debt balance over a shorter period than utilities.<sup>14</sup> On a more basic note, it is incorrect to argue that a firm with a higher debt-equity ratio would necessarily have a lower cost of capital. This argues for utilities to be more highly leveraged; but since debt increases the volatility of equity, a utility with a higher debt-equity ratio would experience an increase in its cost of equity capital. Consequently, there is no theoretical basis for believing that a firm's cost of capital would be lower with a higher debt-equity ratio. (See the appendix for a more detailed discussion of the financial leverage issue.)

Finally, the Senate bill would prohibit FERC from approving rates when an exempt generator receives an unfair advantage from an affiliate, as well as when a state commission disallows cost recovery for existing generating facilities of the utility buyer because of power purchases from an exempt generator. How FERC would enforce these provisions is difficult to foresee.

Two major points should be made about the likely outcomes of a new PUHCA. First, it would give states wide-ranging authority to protect retail customers from abuses by jurisdictional electric utilities. Past fears of state commissions centered on several concerns: losing the

---

right that already exists.

<sup>13</sup> "Conditional" refers to the fact that a utility would first have to request preapproval and preapproved costs may be nullified by "new information which the state commission believes is relevant and material to such cost recovery."

<sup>14</sup> See Naill and Dudley, "IPP Leveraged Financing: Unfair Advantage?".

authority to conduct prudence reviews of power purchases and competitive power procurement mechanisms; lacking access to the books and records of utility holding companies and their affiliates; lacking authority to oversee the spinoffs of existing facilities as exempt wholesale generators; and lacking the right to form a regional regulatory structure to regulate registered holding companies.<sup>15</sup>

The new PUHCA largely would likely placate those state commissions that most opposed any PUHCA changes. For example, the new PUHCA, at least if the provision in the Senate bill passes through conference, would codify the Pike County Doctrine, giving states guaranteed authority to assess the prudence of a utility buying power from individual producers. Further, nothing in the new legislation would restrict the states from establishing power procurement mechanisms.<sup>16</sup> As an additional protection for the states, the House energy bill would require FERC to establish "safe harbor" rules for approving power sales by exempt generators.

The new PUHCA also would give states wide access to the books and records of jurisdictional utilities, their affiliates, and exempt generators selling to those utilities. The House bill gives states the broader authority by allowing them to examine books and

---

<sup>15</sup> See National Association of Regulatory Utility Commissioners, "Resolution Endorsing Legislation to Amend the Federal Power Act to Reform State/Federal Jurisdiction," NARUC No. 9-1991 (March 4, 1991). One major concern of state commissions is that unrestricted utility ownership of wholesale power facilities would create opportunities for utilities to cross-subsidize these facilities through their retail distribution rates. This would especially be true when utilities own and operate wholesale power facilities that sell power to affiliated distribution companies.

<sup>16</sup> Up to now FERC has demonstrated a willingness to defer to the states the outcomes of PUC-approved competitive power procurement programs when the winners are PURPA-qualifying facilities or "true" independent power producers. See Kenneth Rose, Robert E. Burns, and Mark Eifert, *Implementing a Competitive Bidding Program for Electric Power Supply*, (Columbus, OH: The National Regulatory Research Institute, 1991), 98.

records as long as it is "required for the effective discharge of State commission's regulatory responsibilities affecting the provision of electric service."<sup>17</sup>

Regarding spinoffs of existing facilities as an exempt wholesale generator, the final bill either would prohibit the activity (the House bill version) or require state approval (the Senate bill version). A utility generally would want to spin off a plant if it expected to increase profits by repositioning its assets in response to changed market forces.<sup>18</sup> Commissions would have to deal with the thorny problem of allocating the economic value of an existing plant between retail customers and the utility.

One important omission in the new PUHCA is a failure to overturn the contentious Mississippi Power and Light decision.<sup>19</sup> That decision upheld a FERC ruling that prohibits state commissions from regulating the costs allocated to different operating utilities by a multistate holding company. The decision, in effect, disallows states from conducting a prudence review of FERC-approved cost-allocation decisions made by registered holding companies for their utility subsidiaries. States have responded indignantly, and rightly so, to the Mississippi Doctrine, appalled by the fact that they have no control over the costs associated with planning decisions made by a multistate holding company nor over planning decisions made by nonjurisdictional affiliates. There is obviously a regulatory gap for registered holding companies, namely,

---

<sup>17</sup> U.S. House of Representatives, "Comprehensive National Energy Policy Act," section 713, 434. The House bill goes as far as giving the United States district court the authority to issue an injunction requiring compliance with a PUC order.

<sup>18</sup> See Philip R. O'Connor, "IPPs, Devolution and Competition in the Electric Industry," paper presented at Conference on Independent Power Ventures, *Public Utilities Report*, Washington, D.C., October 24, 1988; and Philip R. O'Connor et al., "The Transition to Competition in the Electric Utility Industry," *Journal of Energy Law and Policy*, 8 no. 2 (1988): 222-54.

<sup>19</sup> *Mississippi Power and Light Company v. Moore*, 108 S. Ct. 2428 (1988).

FERC has no authority to approve or reject their generation planning decisions, while states have no authority to regulate the rates of their operating companies.<sup>20</sup>

Two happenings would help to close this regulatory gap. One marginal response would be passage of the provision in the Senate bill giving states authority to assess the prudence of power purchases by an operating utility from an affiliated exempt wholesale generator, both of which fall under the control of a registered holding company. The second, and more significant response, involves giving states the explicit right to form regional compacts with the authority to regulate the planning decisions of registered holding companies. In April 1992 Senator Bennett Johnston introduced S. 2607 that would give states such authority for integrated resource planning.<sup>21</sup>

The second major point to be made is that a new PUHCA would allow the SEC to retain much of its authority over registered holding companies and exempt holding companies. For example, the SEC would continue to regulate registered holding companies regarding their financial and corporate structures, issuance of securities for acquiring wholesale power facilities and other assets, and their service contracts with wholesale power facilities. The SEC also would continue to have the authority to approve mergers and acquisitions by exempt and registered holding companies of other utilities (excluding exempt wholesale generators).

---

<sup>20</sup> See, for example, Charles G. Stalon and Reinier H. J. H. Lock, "State-Federal Relations in the Economic Regulation of Energy," *Yale Journal on Regulation* 7 no. 2 (Summer 1990), 454-57. A discussion of different approaches to close this regulatory gap will be presented in a forthcoming NRRI report on regional regulation.

<sup>21</sup> Senate bill 2607 is the legislative version of the so-called "Arkansas Plan," crafted jointly by a regulated holding company, a city, and a state PUC. The bill would authorize regional integrated resource planning by registered holding companies and the state PUCs regulating their operating companies. See "Johnston Offers Utility Regional-Planning Bill; May Hearing Likely," *Inside F.E.R.C.* (April 20, 1992): 2-3.

## CHAPTER 6

### REMAINING OBSTACLES FOR INDEPENDENT POWER PRODUCTION

Independent power producers still will face several obstacles after a new PUHCA is enacted. It seems uncertain whether the industry over the next few years will experience high growth. The PUHCA impediment represents only one of many that independent power producers currently face. The latent market for independent power may continue because of four factors: the lack of easy access to the regional transmission system, the possibility of self-dealing abuses, the active pursuit of utility demand-side initiatives, and the lack of strong incentives for wholesale purchases by utility buyers.<sup>1</sup>

#### Transmission Access

There is a growing consensus that active and workably competitive wholesale power markets require that potential sellers have access to the market.<sup>2</sup> Competitive forces are nurtured any time more buyers are available to a seller and when more sellers are available to a buyer. For true competition to exist in the wholesale power markets,

---

<sup>1</sup> For example, as discussed later, traditional cost-of-service regulation restricts the incentive of a utility to purchase power from an independent power facility. Most states allow utilities to recover on a dollar-for-dollar basis the prudent costs expended for purchased power. With most utilities currently receiving no profits from buying wholesale power, they may opt for other new resources that are more profitable to them without regard to actual economic costs.

<sup>2</sup> See, for example, Federal Energy Regulatory Commission, *Electricity Transmission: Realities, Theory, and Policy Alternatives* (Washington, D.C.: The Transmission Task Force's Report to the Commission, October 1989); Douglas A. Houston, "Toward Resolving the Access Issue: User-Ownership of Electric Transmission Grids," Policy Insight No. 129 (Santa Monica, CA: The Reason Foundation, August 1991); and Congress of the United States, Office of Technology Assessment, *Electric Power Wheeling and Dealing* (Washington, D.C.: Office of Technology Assessment, May 1989).

it is now widely held that transmission access should be provided on a nondiscriminatory basis to independent power producers and other wholesale producers.

The current debate over whether market-based prices or equal-access rules are preferable for making transmission services more accessible should accentuate the interdependency of the two options. More appropriately, the two options should be viewed as complementary. For example, giving owners of transmission systems greater profit opportunities from selling transmission services should increase access; in addition, equal-access rules would enhance competitive pressures that, in turn, would drive prices for transmission services (as well as other wholesale services) toward market-based levels. Together, market-driven pricing and equal-access rules can represent the optimal strategy for stimulating wholesale power markets.

Even if no transmission legislation is enacted, utilities will face increased pressures to open their transmission systems.<sup>3</sup> A new PUHCA would intensify these pressures as more potential players will want access to wholesale markets so they can market their power; they will push harder for either a political or legal solution to the problem of inadequate transmission access. The "pushers" likely will include some vertically integrated utilities that, for no other than economic reasons, may be more responsive to opening their transmission systems as a quid pro quo for easier transmission access and FERC-approved market-based prices for affiliates located outside their control areas. As transmission access becomes widespread, utilities and perhaps other power buyers in the longer term will have access to more independent power producers. At that time the benefit of a new PUHCA should reach its highest level.

So it seems likely that a new PUHCA would affect indirectly transmission access by stimulating competition and pressures for change. While change in most likelihood would have occurred otherwise, a new PUHCA should secure it earlier in time.

---

<sup>3</sup> It is likely (as of mid-summer) that some legislation will be passed this year that would give FERC more authority to facilitate wholesale transmission access. See "Battle Over Transmission Policy Heats Up As a Showdown in Congress Nears," *Electric Utility Week* (June 8, 1992): 1, 16-17.



## Self-Dealing

Self-dealing transactions may hinder the growth of independent power production. When utilities show partiality toward their affiliates, true independent power producers stand to suffer. Utilities certainly have an incentive to buy power from affiliates as long as they can pass through the costs to retail customers. Even with a least-cost planning process in place and the ability to disallow imprudent costs, regulators under traditional regulation still will have to monitor self-dealing transactions closely.<sup>4</sup>

Allegations of self-dealing abuse emerged during the recent Southern California Edison-San Diego Gas and Electric merger proceedings before FERC and the California Commission.<sup>5</sup> Opponents to the merger argued that Southern California Edison was engaging in improper self-dealing with one of its affiliates, Mission Energy. The Public Utilities Commission staff accused Edison of favoritism toward negotiating and enforcing purchased power contracts from cogeneration and enhanced oil recovery plants partially owned by Mission Energy. As a condition for merger, Edison reached an agreement with the U.S. Department of Justice that the proposed merged utility would not enter into purchased power contracts with affiliates unless prior approval was obtained from the California Commission.<sup>6</sup>

---

<sup>4</sup> For example, regulators would have to carefully review both the price and nonprice provisions of a contract with an affiliate. Further, regulators would need to determine whether the utility restricted transmission access to competitors. By doing so the utility could argue for a higher avoided cost, thereby making affiliate transactions both more defensible and lucrative.

<sup>5</sup> See Dan Seligman, "Self-Dealing Raised in Edison Merger," *The Electricity Journal* 3 no. 6 (July 1990): 8-10.

<sup>6</sup> The agreement was not included in the record of the FERC investigation on whether to approve the proposed merger. The proposal was ultimately rejected by FERC and withdrawn by the parties.

## Demand-Side Initiatives

Many electric utilities recently have undertaken aggressive actions to stimulate demand-side initiatives.<sup>7</sup> Over the next several years, these actions may constitute a major impediment to the development of the independent power industry. Several state public utility commissions have given utilities strong incentives to invest in demand-side assets. For example, some have allowed utilities to offset their sales losses from energy conservation initiatives by adjusting their rates upward outside of a rate-case proceeding; others have allowed higher rates of return for demand-side investments and sharing of benefits from demand-side initiatives.<sup>8</sup>

In the current environment, many utilities have a greater opportunity to earn profits from demand-side investment than from building new generating facilities or from purchasing power in wholesale markets. Until this changes, it seems likely that many utilities will find purchased power as an inferior alternative to more profitable ones such as demand-side investments.

---

<sup>7</sup> See National Economic Research Associates, "Key Issues in Least-Cost Planning," NERA Working Paper No. 10 (August 1991); and Alfred E. Kahn, "An Economically Rational Approach to Least-Cost Planning," *The Electricity Journal* 4 no. 5 (June 1991): 11-20.

<sup>8</sup> See Edison Electric Institute, *Demand-Side Management Incentive Regulation* (Washington, D.C.: Edison Electric Institute, March 1991); and National Association of Regulatory Utility Commissioners, *Incentives for Demand-Side Management* (Washington, D.C.: National Association of Regulatory Utility Commissioners, January 1992).

## Regulatory Incentives

As another obstacle to independent power production, traditional cost-of-service regulation restricts a utility's incentive to purchase power in wholesale markets.<sup>9</sup> Most states allow utilities to recover on a dollar-for-dollar basis the prudent costs associated with firm power purchases.<sup>10</sup> A key question currently before state regulators, not excluding those having in place a formalized least-cost energy process, is whether utilities have an incentive to select the least-cost mix of new resources.

Simply "forcing" a utility, for example, to sign contracts with wholesale power producers for long-term firm power rather than building a new generating facility may not be good policy if the utility stands to gain little if anything by purchasing power. The utility may consider purchasing power as too risky given no opportunity to profit. For example, a dollar-for-dollar passthrough of purchased power costs, in view of possible disallowances, provides the utility with little or no incentive to search actively for third-

---

<sup>9</sup> See Paul L. Joskow, "Expanding Competitive Opportunities in Electricity Generation," *Regulation* (Winter 1991): 25-37; Lewis J. Perl and Mark D. Luftig, "Financial Implications of Third Party Power Purchases," *The Electricity Journal* 3 no. 9 (November 1990): 24-31; and Laura J. Rittenhouse, "Perceptual Survey of the S&P Purchased Power Credit Risk Policy," *The Electricity Journal* (April 1992): 42-52. The last article, which examines survey results conducted for Standard and Poor, showed why many utility executives are not enthusiastic about purchasing firm power from third parties: purchased power financially weakens a utility since it does not allow rate base growth; and power purchases pose an uncompensated risk to a utility--that is, state commissions can disallow costs, which means power purchases create risks that are not offset by an equity return on purchases.

<sup>10</sup> See survey results in Robert E. Burns, Mark Eifert, and Peter A. Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, OH: The National Regulatory Research Institute, November 1991).

party power.<sup>11</sup> Under rate-of-return regulation, a utility receives profits only by investing in assets that are included in rate base. The recent interest by utilities in purchasing firm power may stem more from the risks associated with building new generating facilities than from the abundance of low-priced purchased power.

---

<sup>11</sup> As another risk, rating agencies recently have treated purchased power contracts as a debt equivalent. Standard and Poor, for example, has downgraded some utilities with large nonutility power purchases. See Rittenhouse, "Perceptual Survey of the S&P Purchased Power Credit Risk Policy."

## CHAPTER 7

### NEW CHALLENGES FOR REGULATORS

A new PUHCA would bring new challenges to federal and state regulators alike. FERC would face increased requests for approval of wholesale power sales as well as transmission services. State commissions would see increased requests from jurisdictional utilities for approval of wholesale power contracts, some of which may involve (if allowed) affiliated transactions. States may also encounter more frequent requests from utilities for approval to spinoff ratebased generating facilities as exempt wholesale subsidiaries (assuming it is allowed under the enacted law). (Table 7-1 lists the major responsibilities of, and authority given to, state regulators that may come out of new PUHCA legislation.)

How both FERC and the state commissions would respond to these challenges will have important consequences for retail customers. Support for a new PUHCA presumes that exempt wholesale generators would not exercise market power because of effective regulation by both FERC (in setting prices) and state regulators (in approving least-cost power purchases). While this may ultimately be true, getting there may entail a difficult transitional period for regulators.

A current topic under discussion at FERC centers on the conditions needed for allowing market-based wholesale power rates. Such rates depend on the buyer's willingness to pay for firm power purchases. During the period of 1988 to 1991, FERC approved twenty-eight of forty requests for market-based pricing.<sup>1</sup> Until recently, firm wholesale power transactions were priced almost always on the basis of cost-of-service rules, similar to the way most retail transactions are currently priced.<sup>2</sup>

---

<sup>1</sup> Bernard W. Tenenbaum and J. Stephen Henderson, "Market-Based Pricing of Wholesale Electric Services," *The Electricity Journal* 4 no. 10 (December 1991), 30.

<sup>2</sup> See, for example, Paul L. Joskow, "Regulatory Failure, Regulatory Reform, and Structural Changes in the Electrical Power Industry," Martin Neil Baily and Clifford Winston, eds. *Brookings Papers on Economic Activity: Microeconomics 1989* (Washington, D.C.: The Brookings Institution, 1989), 125-208; and Jan Paul Acton and Stanley M. Besen, *Regulation, Efficiency, and Competition in the Exchange of Electricity: First-Year Results from the FERC Bulk Power Market Experiments*, Rand Report R-3301-DOE (Santa Monica, CA: The Rand Corporation, October 1985).

**TABLE 7-1**

**IMPLICATIONS OF NEW PUHCA FOR STATE REGULATORS**

---

---

- Review of more wholesale transactions, as part of least-cost utility planning or competitive power procurement programs
  - Review of plant spinoffs by exempt holding companies and operating utilities
  - Scrutiny of potentially more anticompetitive activities such as cross-subsidization and self-dealing abuses
  - Authority over prudence of wholesale power purchases
  - Preapproval of wholesale power purchases involving EWGs
  - Determination of effects of wholesale power purchases on cost of capital and reliability
  - Wide access to books and records for overseeing affiliate transactions
  - Review of utility restructuring proposals
- 
- 

The general position of FERC is that market-based pricing would be acceptable for unaffiliated transactions where the seller can show lack of market power. For example, in the case of an Illinois utility selling wholesale power through a subsidiary to an unaffiliated buyer located in (say) Arizona, FERC would look favorably upon allowing the two parties to negotiate a market-based price.

In situations where either the transaction involves affiliated parties or the seller controls transmission facilities that can affect the buyer's supply choices, FERC has acted more cautiously.<sup>3</sup> FERC considers a utility's potential for abusing its control of transmission facilities as a major obstacle to market-based pricing. FERC is expected to approve rules sometime next year defining the conditions under which market-based pricing would be acceptable. The rules are expected to provide a "safe harbor" for traditional utilities and affiliated power producers who agree to offer transmission services on a nondiscriminatory basis.<sup>4</sup> Since these rules will spell out FERC's policy on wholesale power pricing in the years ahead, state commissions may find it in their interest to participate actively in the rulemaking process.

Under a new PUHCA state regulators would have authority over the prudence of power purchases, excepting those involving registered holding companies and their operating subsidiaries. Codification of the Pike County Doctrine would give states explicit authority to disallow wholesale power costs in retail rates.<sup>5</sup> States, for example, could determine whether a particular power purchase is compatible with least-cost planning or the stated goals of a competitive power procurement mechanism. Although most states believe they now have that

---

<sup>3</sup> In a speech before the American Bar Association on August 13, 1991 in Atlanta Georgia, Chairman Martin L. Allday remarked that:

We've three major concerns in looking at market power: (1) whether the seller can dominate the buyer's generation supply choices; (2) whether the seller controls transmission, so that other competitors can be shut out of the market; and (3) potential abuses of affiliate relationships (p. 3). . . . The biggest hurdle in getting quick FERC approval is and will continue to be market power in transmission. That's because control of transmission lets sellers shut out competitors and prevents buyers from getting to the lowest cost supply source (p. 5).

<sup>4</sup> Chairman Allday, in his American Bar Association speech, commented that "as long as APPs [affiliated power producers] and traditional utilities have on file with us [FERC] an acceptable open access transmission tariff for their entire system, or for those lines that the buyer could use to reach competing suppliers, we should presume that market power has been mitigated (p. 6)."

<sup>5</sup> FERC will continue to have preemptive authority over the reasonableness of wholesale power *rates*.

authority, codification in new energy legislation would avoid any uncertainty over possible litigation.<sup>6</sup>

Notwithstanding this authority, states would have the task of closely monitoring wholesale purchases. Particularly whenever self-dealing occurs, state commissions face the difficult task of assuring ratepayers that utilities are pursuing least-cost activities.<sup>7</sup> Whatever else may be true, utilities would have an incentive to favor power purchases from affiliates, assuming other things are the same. Self-dealing abuses could lead to higher retail rates and the unfair advantage of utility affiliates over other producers, some of whom may have lower costs.

The informational problem, a constant nemesis for rate-of-return regulation, would be accentuated if regulators were confronted by a rash of self-dealing requests. For example, regulators would have to scrutinize both the price and nonprice provisions of a proposed contract with an affiliate. Further, they would need to determine whether the buying utility gave its unfair market advantages by restricting transmission access to competitors. That is, even when the utility has the availability of power from a large number of sources, it could restrict their entry (for example, by

---

<sup>6</sup> Even without codification it is unlikely that state commissions would face a challenge from utilities in exercising the authority to disallow wholesale power purchases. In a 1991 survey conducted by the U.S. General Accounting Office (see U.S. General Accounting Office, *Electricity Supply: Potential Effects of Amending the Public Utility Holding Company Act*, GAO-RCED 92-52 [Washington, D.C.: U.S. General Accounting Office, January 1992]), forty commissions (out of forty-eight that responded) indicated that "they have the authority to disallow utilities from passing on, through retail rates, a portion of the cost of a wholesale power purchase approved by FERC (p. 32)."

<sup>7</sup> Some states have acted to minimize self-dealing abuses (U.S. General Accounting Office, *Electricity Supply: Potential Effects of Amending the Public Utility Holding Company Act*, 33). The Virginia State Corporation Commission, for example, prohibits self-dealing transactions consummated by means of a competitive power procurement mechanism. Several states, on the other hand, allow interaffiliate transactions, many of which require prior regulatory approval. For a detailed exposition of the problems associated with self-dealing transactions, see Robert E. Burns et al., *Regulating Electric Utilities with Subsidiaries* (Columbus, OH: The National Regulatory Research Institute, 1986).



denying transmission access) in its service area.<sup>8</sup> By doing so the utility could argue for a higher avoided cost, thereby making affiliate transactions more defensible.<sup>9</sup>

A new PUHCA would create more opportunities for utilities to form subsidiaries. Any time a utility diversifies, there exists the problem of cross-subsidization. As noted below, cross-subsidization can arise either from improper cost shifting between different lines of business or from predatory pricing (namely, setting price below cost in the more competitive market). In either case, a utility may attempt to impute more of the common costs to the regulated side of its business where ratepayers have limited options. The utility would have the incentive to misallocate costs until regulated customers are being charged a profit-maximizing price. It is assumed, of course, that regulation was previously effective in controlling the prices and profits of the utility below the unregulated-monopoly levels. The utility, for example, may raise retail rates to help fund its wholesale power subsidiary or other nonutility businesses.

The strongest incentive for cross-subsidization generally lies with the ability of a regulated utility to increase its revenues in markets where it has monopoly power by reallocating costs from markets where it faces more competition. Cross-subsidization, while always raising rates in monopoly retail markets, may not always result in lower wholesale power rates.<sup>10</sup> When cross-subsidization results in what is called predatory

---

<sup>8</sup> As FERC is given more authority to require transmission access such discriminatory actions are less likely to happen. This implies that opportunities for self-dealing abuses should diminish (although not be eliminated) as a problem for both FERC and state commissions.

<sup>9</sup> The utility also may have an incentive to deter least-cost actions such as demand-side initiatives to inflate its avoided costs. The utility could then purchase power from an affiliate under inflated avoided cost rates, retaining all of the profits through its affiliates. If this happens, self-dealing would hamper rather than promote least-cost planning objectives.

<sup>10</sup> See, for example, Lorenzo Brown, "Modelling Diversified Utilities and Cross-Subsidization," *Resources and Energy* 10 (December 1988): 213-24.

pricing (pricing below cost) inefficiencies arise both because of higher prices in retail markets and the displacement of efficient producers in wholesale markets.<sup>11</sup>

Cross-subsidization can be avoided if regulators are able to segment costs perfectly by customer class or service. Since they cannot, largely because of the presence of common costs, utilities have the opportunity for shifting costs to markets in which consumers have few choices. For example, a utility might impute more of the common costs associated with management functions to retail customers, who have fewer options than wholesale buyers.<sup>12</sup> In any event, to the extent a new PUHCA would increase utility diversification, state regulators will have to pay closer attention to the possibility of cross-subsidization.

State regulators can act to mitigate some potential problems associated with self-dealing, cross-subsidization, and other anticompetitive activities (for example, collusive arrangements among utilities). First, they can more vigilantly monitor the cost of a utility and its affiliates.<sup>13</sup> The new PUHCA would allow state regulators wide access to the books and records of exempt wholesale generators and their affiliated utilities. Besides requiring additional commission staff resources, monitoring may produce

---

<sup>11</sup> The possibility of predatory pricing is severely diminished anytime a utility affiliate has to compete with other suppliers, namely, PURPA-qualifying facilities, independent power producers, and outside utilities, in addition to demand-side initiatives. It seems highly unlikely that the utility affiliate could permanently drive out these competing sources by temporarily setting prices below cost. Further, funding a losing business with higher rates to some consumers for an extended period (which may be necessary to drive out competitors) may ultimately harm the parent company. This is because some of its subsidizing consumers could end up finding new electricity suppliers and the company could be threatened with antitrust or civil suits from its competitors.

<sup>12</sup> Different ways in which wholesale power producers can engage in cross-subsidization are discussed in Tenenbaum and Henderson, "Market-Based Pricing of Wholesale Electric Services."

<sup>13</sup> While this would require additional staff resources, less staff resources may be expended on such activities as reviewing the construction costs of new utility power plants and assessing how these costs should be incorporated into rates. Consequently, on net, the requirements on staff resources for many state commissions may not increase.

uncertain outcomes because of the problem of distinguishing "legitimate" costs from "illegitimate" costs incurred by the utility and its affiliates. As discussed earlier, regulators, even with their best efforts, may lack the necessary information to prevent all possible abuses.<sup>14</sup>

A second option for regulators (presented here more as a theoretical construct) is to link retail rates with the profits earned by wholesale power affiliates.<sup>15</sup> For example, since cross-subsidization and self-dealing abuses would result in higher profits to affiliates, regulators can "give back" part of these profits to retail customers in the form of lower rates. This option would diminish the need for regulators to monitor possible abuses, since the utility would have little incentive to engage in such activities; ideally, every dollar of profit earned by abuses would be returned to retail customers. Although theoretically appealing, this option would be difficult to enforce as regulators would have to account for the profits of an affiliate that are related to other factors in addition to cross-subsidization and self-dealing abuses. Further, it would invite legal wrangling resulting in high litigation costs.

Third, and perhaps the most attractive long-term option, regulators can enforce an incentive-based mechanism by which prices to retail customers would deviate from a utility's actual costs. By breaking the linkage between price and cost, a utility's incentive to inflate prices for self-dealing transactions or to shift costs to retail services would

---

<sup>14</sup> The fundamental problem of allocating common costs between different services is discussed in William J. Baumol, Michael F. Koehn, and Robert D. Willig, "How Arbitrary Is Arbitrary?--or, Toward the Deserved Demise of Full Cost Allocation," *Public Utilities Fortnightly* (September 3, 1987): 16-21.

<sup>15</sup> The idea of linking regulated prices with profits earned in unregulated or lightly regulated activities are discussed in Tracy R. Lewis and David E. M. Sappington, "An Informational Effect When Regulated Firms Enter Unregulated Markets," *Journal of Regulatory Economics* 1 (March 1989): 35-46.

diminish.<sup>16</sup> As an example of one such mechanism--price-cap regulation--state regulators could establish maximum allowable retail prices in core markets based on indices divorced from the cost changes for any individual utility. Assuming a textbook application of price-cap regulation, when a utility incurs higher costs, for example, by paying an affiliate an excessive price for purchased power or by shifting costs to its retail business, it gains little if anything. The inability of the utility under idealized price-cap regulation to pass through higher reported costs to retail customers diminishes the possibilities for self-dealing abuse, cross-subsidization, and collusive agreements.

As an additional benefit, price-cap regulation when properly applied would help assure that different wholesale power producers will compete on an equal basis. Self-dealing abuses and cross-subsidization, both of which place utility unaffiliated power producers at a market disadvantage, would lessen over time.<sup>17</sup>

---

<sup>16</sup> See, for example, Mark Newton Lowry, "The Case for Indexed Price Caps for U.S. Electric Utilities," *The Electricity Journal* 4 no. 8 (October 1991): 30-37. Under price-cap regulation, a utility may decide to sell surplus generating capacity at market-based prices without the need to form a subsidiary. As argued, price-cap regulation would provide a utility with the incentive to minimize costs in its regulated markets. Support for price-cap regulation in mitigating cost shifting is also discussed in Ronald R. Braeutigam, "Regulatory Reform for Diversified Public Utilities: For Better or for Worse?" *Resources and Energy* 14 nos. 1/2 (April 1992): 103-22.

<sup>17</sup> While it is argued here that price-cap regulation can help to mitigate anticompetitive effects, it may have disadvantages over rate-of-return regulation in achieving other regulatory objectives. Further, the theoretical benefits of price-cap regulation may not transpire because of several factors including political pressures. See, for example, Kenneth W. Costello and Sung-Bong Cho, *A Review of FERC's Technical Reports on Incentive Regulation* (Columbus, OH: The National Regulatory Research Institute, 1991); and Douglas N. Jones, "Discussion of 'Regulatory Reform for Diversified Public Utilities: For Better or for Worse?' by Ronald Braeutigam," *Resources and Energy* 14 nos. 1/2 (April 1992): 123-28.

## CHAPTER 8

### CONCLUSIONS

A new PUHCA makes economic sense when independent power producers have the potential to supply wholesale power markets with a low-cost source of generating resources. The highly vertically integrated structure of the electric industry may no longer serve the best interests of retail electricity consumers. Further, the displacement of PURPA-qualifying facilities with independent power facilities may improve the economic performance of the electric industry and benefit retail consumers. By lifting a costly barrier for new power producers, a new PUHCA should help accentuate the competitive forces currently propelling the electric industry. Such forces may push the industry closer to a more economical structure where the industry's generation component will become more controlled by profit-driven entrepreneurs and less by tight regulatory rules.

While the independent power industry (the major direct beneficiaries of a new PUHCA) has barely gotten off the ground, it has a promising future. In addition to a new PUHCA, the rapid growth of utility power procurement programs, the opening of transmission systems to unaffiliated producers, and FERC's market-based pricing together will nurture the growth of the independent power industry. As long as the industry is given the chance to compete equally with other supply side and demand-side resources, how much it actually grows becomes irrelevant from the perspective of society at large.

The independent power industry may not suddenly take off over the next few years, even in the presence of a new PUHCA. Producers will still have several obstacles to clear before they attain the status of major players in the electric industry. They will need to compete with other power sources as well as demand-side initiatives for gaining acceptance by both utility buyers and their regulators.

Finally, a new PUHCA would offer new challenges to regulators. Easing the constraints on utilities to form wholesale power subsidiaries would heighten their opportunities to engage in anticompetitive activities potentially detrimental to retail electricity consumers. State regulators

in particular may have to provide additional safeguards so that consumers would be protected against such activities. Some, for example, may intensify their oversight activities of utilities with wholesale power subsidiaries, while others may decide on a new regulatory regime to protect the core customers. Experience has shown that as an industry becomes more competitive its regulators encounter greater pressure to ease the rigid principles of rate-of-return regulation in accommodating new market conditions. This may happen in the case of the electric industry in the coming years.

## APPENDIX

### THE FINANCIAL LEVERAGE ISSUE

#### Introduction

One potential cost savings from nonutility power generation has sparked a great deal of controversy, much debate in Congress with regard to PUHCA reform, and undoubtedly has continued debate as the issue is likely to move to the state public utility regulatory commissions. That controversy is the extent to which nonutility generators (NUGs) have a lower cost of capital than their competing privately owned utilities (IOUs).<sup>1</sup> Of course, if the alleged lower cost of capital is attributed to greater operating efficiencies there would be little controversy; but conceivably a lower cost of capital could result not from the NUGs doing a better job but from the effects of public utility regulation on an IOU's capital structure and cost of capital. If this were the case, then we would not have what some would call a "level playing field"; that is, more and more capacity would flow to the NUGs not because of superior performance but because of a quirk in the regulatory process.

This Appendix addresses this issue and its many ramifications for the cost of electric power to consumers. The issue, in more definite terms, revolves around the following suggestion: *the cost of capital for an NUG is lower than the cost of capital for an IOU because the utility is limited by the regulatory process in its ability to finance the assets of the firm with debt capital whereas the NUG has no such limits.* Specifically, a typical IOU is limited to a debt capacity of approximately 50 percent, while in the unregulated market of the NUG projects are often financed with higher levels of debt. Since debt financing is generally less costly than equity financing, the common belief is that a higher proportion of debt gives the NUG an inherent advantage with a lower cost of capital unavailable to the IOU. Although the advantage is real it is unfair since the

---

<sup>1</sup> The cost of capital, for the purposes here, is defined as the weighted average of the annual percent interest cost of long-term debt, preferred dividends, and dividends and long-term capital appreciation of the common stock. Measurement is accomplished by market values.

utility has debt limits imposed by the regulatory commissions whereas the NUG has no such limits.

The issue, then, is a capital structure problem or more specifically an optimization problem where the objective is to determine the optimum capital structure, which is defined as the capital structure that maximizes the value of the firm or minimizes the cost of capital.<sup>2</sup> The capital structure is defined as the mix of long-term debt and equity financing.<sup>3</sup> Put another way, if a 50 percent debt capital structure is optimum then the NUG will have no advantage and indeed may be disadvantaged by using higher levels of debt. If on the other hand higher proportions of debt are optimum then the advantage may shift to the NUG. In essence, knowing an optimum capital structure helps to determine whether or not an NUG has a cost of capital advantage over an IOU when bidding for new capacity.

### **The Naive Capital Structure**

While determining an optimum capital structure is complex and no absolute solution exists, a reasonable approximation can be made by applying a variety of theoretical approaches. Consider two firms that are exactly alike in every respect except that Firm A is financed entirely with equity and Firm B is financed with 50 percent debt (at 9 percent interest expense) and 50 percent equity. Each firm has total assets of \$4,000, total sales of \$2,000, and an operating margin of 40 percent. Each of these factors is held constant to determine the effects of added debt upon the cost of capital. The income statement of each firm is depicted in Table A-1 where the percent return on equity is simply the net income divided by total equity, which is \$4,000 in the case of Firm A and \$2,000 for Firm B.

---

<sup>2</sup> The cost of capital literature is extensive and extremely detailed. The analysis to follow is a summary sketch of that literature. An excellent and thorough examination of the entire subject is presented in Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance*, 4th ed. (New York: McGraw-Hill, Inc., 1991), Chpts. 16-19. Much of the discussion here draws on the work of Brealey and Myers.

<sup>3</sup> The analysis to follow ignores the complications of preferred stock. This simplification will in no way materially affect the conclusions of the analysis on capital structure.



Given these conditions, then, what value will the investment community place on each firm assuming that each investor will attempt to maximize the return for a given level of risk or correspondingly minimize risk for a given level of return? To solve this question, consider for the moment two investment alternatives of \$2,000 in Firm A or \$2,000 in Firm B. Which will be preferred? The obvious answer is the investment in Firm B since that investment produces an annual income of 31 percent compared to the investment in Firm A which produces only 20 percent annually. As a consequence, the investment community will bid up the shares of Firm B, lowering its cost of capital and giving Firm B an advantage over Firm A in any sort of competitive dual between the two firms. This advantage will exist for any and all levels of debt. Graphically, Figure A-1 depicts the cost of capital as related to the capital structure or the amount of debt, given the conditions just described.

**TABLE A-1**  
**HYPOTHETICAL INCOME STATEMENT**

	Firm A	Firm B
Total Revenues	\$2,000	\$2,000
Operating Expenses	<u>1,200</u>	<u>1,200</u>
Operating Margin	800	800
Interest Payments @ 9%	<u>0</u>	<u>180</u>
Net Income	800	620
% Return on Equity	20%	31%



**Fig. A-1. Graphical representation of the cost of capital.**

Does the NUG gain an advantage by the debt limits placed on the IOU by regulatory bodies? The clear and unequivocal answer given the investment alternatives as outlined and Table A-1 and Figure A-1 is that the NUG does indeed enjoy a substantial advantage well beyond any operating efficiencies it may or may not enjoy. Either the IOU should be allowed to increase its debt or the NUG's debt levels should be restricted.

The question is not so easily resolved, however. The behavior of the cost of capital as a decreasing function of debt levels (as depicted in Figure A-1) has serious flaws and perhaps can best be referred to as the naive model. It is naive in the sense that it ignores the greater risk of higher levels of debt and the efficiency of modern capital markets.

### **The Modigliani and Miller Capital Structure**

To adjust for these deficiencies, consider an investor with \$2,000 to invest, and who is willing to accept the risk of Firm B with its greater debt level. The investor could, of course, purchase all of the shares of Firm B. The investor, on the other hand, could also achieve exactly the same risk-return parameters by purchasing all of the shares of Firm A with the same \$2,000 and a personal loan amounting to 50 percent of the cost of the shares of Firm A. In essence, the investor could substitute personal debt for corporate debt. Table A-2 depicts these alternative investment strategies.

Each investment strategy yields exactly the same result: each has a return of 31 percent, the same business risk since the firms are identical in every respect except for the use of debt, and the same financial risk since both investments employ \$2,000 of debt at an interest rate of 9 percent. The investment community therefore will be indifferent between these investment alternatives. As a consequence neither firm will enjoy an advantage because of different capital structures. The total value of the firm is independent of the capital structure since the capital structure will not affect the risk-return parameters of the investor even though it may affect the risk-return parameters of the equity of the firm.

**TABLE A-2**  
**ALTERNATIVE INVESTMENT STRATEGIES**

Investment	Strategy	
	One	Two
Personal Equity in Firm B	\$2,000	
Personal Equity in Firm A		\$2,000
Personal Debt in Firm A @ 9%		\$2,000
Return to Investor		
Net Dollars	620	620*
% Return on Personal Equity	31%	31%

\*Equal to \$800 income from the investment in Firm A less the 9 percent cost of the personal debt or \$180.

Put another way, the investment community as a whole receives \$800 from each investment strategy. In the case of Strategy One, the investment community receives \$620 from the equity investment and \$180 from the corporate debt sold to investors. In Strategy Two, the investment community receives \$620 from the equity investment and \$180 from the investor's personal debt borrowed from the investment community for a total of \$800 of income to the macro investment community.

This result is the now well known Modigliani and Miller (M & M) Propositions I & II:<sup>4</sup> the value of a firm is a function of the risk-return parameters of the *assets* of the firm and the cost of capital is constant for all capital structures. This is because the cost of equity will rise with

---

<sup>4</sup> Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48 (June 1958): 261-97.

greater debt to exactly offset the cost reducing properties of lower cost debt.<sup>5</sup> This cost of capital result is depicted graphically in Figure A-2.

Does the NUG have a cost advantage over the investor-owned utility? The obvious answer is *no*, given the M & M conditions; there is no controversy--the playing field is level, and state regulatory commissioners need not worry that the regulation of the capital structure of a utility places them at a competitive disadvantage relative to NUGs. A pretty easy and straightforward result.

### **Perfect Capital Markets**

Like the naive model, however, the real world is not quite as simple and straightforward as the M & M world just described; Modigliani and Miller would be the first to agree. Before developing a capital structure approach more in keeping with reality, however, it should be noted that one important assumption of the M & M propositions is, in all probability, very close to the world of large electric utilities. M & M assume a perfect capital market where personal debt can be substituted for corporate debt at the same rate of interest and where assets with equal risk-return parameters will have equal prices.

The literature and evidence on this subject is enormous and new evidence is being developed continuously. Still in the case of large publicly traded firms in the United States, any capital market imperfections without doubt are so small as to have negligible effects on the cost of capital or the value of the firm. Furthermore, any potential problems with the debt substitution assumption will also be inconsequential since there are a whole host of active professional and institutional investors fully capable of borrowing at corporate rates. Modern capital markets, as they present themselves to a large utility or NUG, are close enough to the M & M assumptions to conclude the validity of the M & M results for the purposes here.

---

<sup>5</sup> See Figure A-2 for a graphical illustration of this cost of capital effect.

**Fig. A-2. Graphical representation of the cost of capital**

**under M & M conditions.**



## **Tax Modifications to the M & M Capital Structure**

While the actual performance of modern capital markets does not negate the M & M conclusions, the existence of taxes does. Up to this point the examples have assumed a world of no taxes or more specifically a world where interest cost is not deductible.

To clarify the effects of corporate taxes, Table A-3 is a partial reproduction of Table A-1 beginning with the operating margin for our two identical firms but adding taxes at a rate of 35 percent. Table A-4 is a partial reproduction of Table A-2, which describes two investment strategies of purchasing all of the shares of Firm B or all of the shares of Firm A, with half the purchase price of Firm A obtained from personal borrowing.

Clearly the inclusion of taxes, or more accurately the deductibility of interest payments, has a major effect. The investment strategy of purchasing the shares of Firm B which has 50 percent debt is more profitable than the purchase of Firm A with the use of personal debt instead of corporate debt. Specifically, personal leverage has not equated the investment strategies because the interest expense of Firm B represents a tax deductible expense. The use of debt in the realistic taxable world has therefore given Firm B a greater market value or lower cost of capital and a consequent competitive advantage over Firm A because of its financial structure rather than any operating efficiencies. (It should be noted here that the existence of personal taxes does not change this conclusion given relatively similar corporate and personal tax rates.)

As before, we can depict this situation graphically as is done in Figure A-3, which is close to the behavior of the cost of capital as depicted in Figure A-1, the naive model. It is not exactly the naive model, but clearly the existence of taxes creates a decline in the cost of capital with added debt. If this were the total story, then the NUG is advantaged. There are, however, at least three factors that reduce the extent of the decline and in fact cause the cost of capital curve to turn up at some level of debt.

**TABLE A-3**  
**HYPOTHETICAL INCOME STATEMENT**  
**INCLUDING CORPORATE INCOME TAXES**

	Firm A	Firm B
Operating Margin	\$800	\$800
Interest Expense @ 9%	<u>0</u>	<u>180</u>
Net Income Before Taxes	800	620
Taxes @ 35%	<u>280</u>	<u>217</u>
Net Income	520	403
% Return on Equity	13.00%	20.15%

**TABLE A-4**  
**ALTERNATIVE INVESTMENT STRATEGIES**  
**WITH CORPORATE INCOME TAXES**

Investment	Strategy	
	One	Two
Personal Equity in Firm B	\$2,000	
Personal Equity in Firm A		\$2,000
Personal Debt in Firm A @ 9%		2,000
Return to Investor		
Net Dollars	403	340*
% Return on Personal Equity	20.15%	17.00%

\*Equal to \$520 income from the investment in Firm A less the 9 percent cost of the personal debt

of \$180.

**Fig. A-3. Graphical representation of the cost of capital  
under M & M conditions including corporate taxes.**

### Other Adjustments to the M & M Capital Structure

The first factor is that interest deductibility is an advantage only when the corporation pays taxes; this is an obvious statement but one that will initially reduce the cost of capital as small amounts of debt are added but at some point the cost of capital would eventually increase. In the example, both firms earn \$800 before interest and taxes *on average*.

If, for example, this average consists of equal probabilities of \$1,600 and \$0 then the tax deductibility of interest will benefit Firm B only when the earnings are \$1,600. At \$0 earnings there is no tax benefit other than the possibility of a tax-loss carry-forward which, while an advantage, is nevertheless a major detriment to the tax benefits of debt financing.

The implication for the cost of capital is that it will decline initially from the tax deductibility of interest when the probability that earnings do not exceed the interest obligation is rather small. As the probability of net losses increases, however, the benefits of tax deductibility decline and as a consequence the cost of capital begins to increase. One cannot generalize what levels of debt will create an increase since business risk differs from firm to firm. One can generalize, however, that the increasing probability of loss created by higher levels of debt eventually will increase the cost of capital after an initial decline.

A second factor contributing to an increase in the cost of capital beyond some level of debt is the fact that as the capital structure of the firm shifts more toward debt and away from equity, the business risks of the firm begin to shift to the debt instruments; that is, at very small amounts of debt the probability of default on the interest or principal obligations caused by a business downturn, poor management, or just plain bad luck is also small. As debt levels increase, however, the probability of default begins to increase as a function of business risk such that in the extreme (100 percent debt) the cost of capital must return to the cost of equity since 100 percent debt is equivalent to 100 percent equity. This is, of course, precisely why (holding all other

factors constant) lower bond ratings and the consequent rise in interest costs are directly associated with higher levels of debt.

In essence, as debt is added to the capital structure the debt instruments begin to take on the same risks as the firm's common stock. As a consequence, the cost of the debt begins to approach the cost of the equity. The result is the cost of capital declining with small amounts of debt when this risk shifting is insignificant, but beginning to rise as larger and larger amounts of debt are used in the capital structure. The reason for this is that the debt instruments begin to take on the business risk of the firm as equity is replaced. In general, the effect is similar to the declining value of interest-payment tax deductibility mentioned earlier.

The third factor relates to the costs of financial distress. These costs become very difficult to quantify but exist nevertheless. They include the administrative, legal, and accounting costs of bankruptcy as well as the costs of operating inefficiencies that result inevitably when a firm is either close to bankruptcy or actually in bankruptcy. Examples of such operating inefficiencies include deferred maintenance, a loss of the better employees as they seek greater security with other firms, elimination of profitable but cash poor activities, and the addition of unprofitable but cash rich activities. The list could go on and on. The point is that as debt levels are increased the probability increases that these costs will materialize. Furthermore, actual bankruptcy is not required for many of these cost to exist nor can they be ignored if a recovery from bankruptcy is expected.

As with the previous analysis, the potential costs of financial distress have very little effect on the cost of capital with small amounts of debt. As debt levels increase, however, there comes a point when the cost of capital begins to increase as the possibility increases that some or all of these costs will enter into the income statement of the firm.

### **The Real World Cost of Capital**

To summarize, the tax deductibility of corporate interest payments creates a condition where added levels of debt can be associated with a declining cost of capital.

The decline is independent of operating efficiencies. Hence, a firm with higher levels of debt is advantaged over an identical firm with lower levels of debt. This advantage, however, exists only for moderate amounts of debt. As debt levels become large, the firm's cost of capital begins to increase because of three factors: (1) a decline in the value of the tax deductibility of interest payments caused by an increasing probability of loss, (2) a shifting of greater amounts of business risk to the debt instruments of the firm causing the cost of capital to approach the cost of equity, and (3) the increasing probability that the firm will incur some or all of the very real costs of financial distress. The result of these several factors is that the cost of capital initially declines with added debt, but at some point begins to increase with higher and higher levels of debt. Graphically, the general consensus is that the cost of capital curve is a saucer-shaped curve as depicted in Figure A-4. There is in fact an optimum capital structure that will minimize the cost of capital or maximize the value of the firm. Most financial experts agree, however, that the optimum is not a point but rather a fairly large range of debt and equity combinations.

### **The Cost of Capital Advantage for the NUG**

What, then, does Figure A-4 reveal about the original question? Does the NUG have a competitive advantage over the traditional IOU in terms of a lower cost of capital resulting from the unregulated nature of the NUG and its consequent ability to establish a capital structure with a larger amount of debt? As in most economic situations an absolute, unambiguous answer cannot be established. Figure A-4 should allow a reasonable approximation, however.

Assuming as before that an NUG has no operating or other nonfinancial edge, Figure A-4 suggests that any advantage that an NUG may enjoy from its capital structure is extremely limited and in all probability does not exist. In fact, Figure A-4 suggests that, in virtually every situation, the capital structure of an NUG is more likely to be neutral in its competition with the typical IOU. For an NUG to enjoy a capital structure advantage the capital structure of the IOU is assumed to be less than optimum; that is,

**Fig. A-4. Consensus cost of capital reflecting real world conditions.**



if the amount of debt of an IOU is at the optimum which minimizes the cost of capital the NUG cannot enjoy an advantage. At the minimum the capital structure effect is neutral. If the IOU's capital structure falls within the large flat area of the cost of capital curve of Figure A-4, the NUG's capital structure could only be neutral or a *disadvantage* in its competition with the IOU in the unlikely event that the NUG does not employ an optimum capital structure. The playing field is level and there is no reason either to regulate the NUG or deregulate the IOU's capital structure. Both have minimized the cost of capital and the consumer is well served.

Of course, it is possible that the IOU is not at the minimum cost of capital. In Figure A-5, the IOU would employ an amount of debt that is less than the amount implied at point A. Its amount of debt would be insufficient to minimize the cost of capital. If, on the other hand, the actual amount of debt placed the capital structure of the IOU at point B in Figure A-5, the NUG would enjoy a cost of capital advantage at any debt level that was greater than point B but less than point C. Such a condition could exist, but that would require the capital structures of virtually all of the IOUs to be somewhat less than optimum, which may be possible. Such a situation seems highly unlikely for several reasons, however.

First, the capital structure of a contemporary electric utility company is the result of massive amounts of research, experimentation, experience, and good judgment by utility executives, commissions, and academics with the general agreement that a capital structure with approximately 50 percent debt is optimum.

Second, if the typical IOU were capable of reducing its cost of capital with added debt, rates of return on the common stock of those IOUs would be lower than what one would expect from equity securities with comparable levels of business and financial risk. The existence of such abnormal returns has not been demonstrated to anyone's satisfaction.

Third, cost of capital calculations by their nature are imprecise and should not be applied in a way that calls for a great deal of accuracy. If the IOU is operating with a suboptimum capital structure, it is reasonable to suggest that the deviations from the



**Fig. A-5. Hypothetical electric utility cost of capital curve.**

minimum are not great and are more than likely within the measurement errors expected when estimating the cost of capital.

Last, it is crucially important to recognize that if the IOU's capital structure indeed is less than optimum, policymakers should *not* expend their energy on reducing the amounts of debt issued by the NUGs. Instead, they should consider either deregulating the capital structures of the IOUs or increasing the amounts of debt allowed the IOU to benefit the consumer. In other words, if the IOU capital structure is inappropriate the issue has nothing to do with the existence of the NUGs. The cost of capital is not at a minimum and should be reduced independent of the potential competition from the NUG.

In addition, it should be noted that the greater use of debt by the NUGs has a far better explanation than the possibility of suboptimum capital structures of the IOUs. The most obvious explanation is that the capital structures of both the NUG and the IOU fall within the large flat area of the cost of capital curve. More specifically, it is reasonable to conclude that the typical IOU debt limits of approximately 50 percent are at the minimum debt levels required to achieve an optimum, and that the NUG uses of debt of 75 percent to 90 percent are also within the optimum range of the minimum cost of capital.

It is also the case that the saucer-shaped cost of capital curve is perfectly consistent with a state commission limiting debt to approximately 50 percent of capital even though many utility executives and others believe there is greater debt capacity within most electric utilities. If the 50 percent level occurs early within the large flat area of the cost of capital curve, there is no compelling reason either from the consumers' point of view or the stockholders' to expand the amount of debt within the capital structure. The cost of capital has been minimized and adding debt is of no value even though more debt could be carried without jeopardizing service to the customer.

It seems, then, that there is very little to suggest that the capital structure of the IOU is producing a cost of capital greater than the minimum available, which is required to conclude that the greater debt levels employed by the typical NUG provide a

competitive advantage. Suboptimum behavior by the IOU is possible, but it would seem that burden of proof lies with those who claim an advantage for the NUG.<sup>6</sup>

At this point, it should be noted that the NUG may have a lower cost of capital than the IOU not because of a capital structure advantage but because of some other business advantage that either increases the net income or reduces risk. As noted, these factors could be operating or managerial efficiencies, a modern plant, even a variety of risk reducing activities such as shifting market risk to the IOU. These activities, however, are not capital structure issues, but asset issues. If they generate an unfair competitive advantage, the commission should react not by becoming involved in a capital structure debate but by focusing on the asset issue directly.

It is also important to recognize that this discussion has focused on the long-term securities of the IOU. That is, long-term debt represents approximately 50 percent of total capitalization but all debt, both short and long, represents approximately 65 percent of all capital of the typical IOU. Correspondingly, it is less clear from the balance sheet of the typical NUG whether or not the long-term debt on the books is permanent or temporary in the sense that principal is repaid by substituting debt for equity or simply replacing existing debt with new debt. These short-term, long-term aspects of the capital structure issue are usually unique to the particular situation and typically are not generalizable. They are mentioned to recognize that the use of debt of all types may not be quite as different between the NUG and the IOU as is often portrayed. More specifically, the IOU finances more than 50 percent of its assets with debt including short-term debt. The NUG may, on a permanent basis, have less long-term debt than the contemporary balance sheet would indicate. In other words, the flat area of the cost

---

<sup>6</sup> It should be noted that these arguments do not rely on a saucer shaped cost of capital curve. The optimum could be a point with a curve shaped more like a "V." Such a curve prohibits a situation where both the IOU and the NUG are at optimums with different debt levels holding all other factors constant. It would still be the case, that to demonstrate an advantage, independent evidence would have to show that IOU debt levels are sub-optimum.

of capital curve need not be very long for both the IOU and the NUG to be operating with an optimum capital structure.

### **Summary and Conclusions**

The cost of capital as related to the amount of corporate debt is neither the constantly declining curve of the naive model, the M & M tax deductibility world, nor of the constant value model of the nontax M & M model. Instead, the curve is more complex describing a saucer shape where it initially declines from the tax-deductibility of interest payments: it flattens out in an area where the tax deductibility is neutralized from the increasing probability of eliminating the tax-deductibility value, the shifting of business risk to the debt securities of the firm, and the increasing probability that some or all of the costs of financial distress will be incurred by the firm. Eventually, these last three factors will overwhelm the tax-deductibility value of debt and create an increasing cost of capital curve. Under these conditions, it is unlikely that an NUG will have a cost of capital advantage over the IOU. For such an advantage to exist one must assume that the IOU's current debt level is less than optimum, which seems highly unlikely on several counts.

As a consequence, it is reasonable to conclude that the NUG is not advantaged as a result of the existence of debt limits placed upon the IOUs by regulators. The capital structures of an NUG and IOU are neutral in the competition between them. It is possible, however, that the NUG may be advantaged with a lower cost of capital not because of capital structure differences but because of other advantages which could include operating or managerial efficiencies, less risky or more lucrative markets, or a more modern physical plant, to name a few of the many potential influences on the cost of capital. The analysis here has held all of these factors constant to isolate the capital structure effects. These other factors could be real and may give the NUG a major advantage. The inescapable conclusion from the analysis here is that the greater amounts of debt that an NUG is able to employ in its capital structure is unlikely to give it a competitive advantage. If there is a cost of capital advantage it does not arise from the capital structure but, instead, must be attributed to other operating factors.