

# MUNICIPALIZATION: OPPORTUNISM AND BYPASS IN ELECTRIC POWER

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## I. INTRODUCTION

As of April 1997, more than forty municipalization proposals have emerged in seventeen states as a means of evading competition transition charges for stranded costs proposed by state commissions. Stranded costs equal the difference between expected regulated net-revenues and the net-revenues obtained in competitive markets from formerly regulated assets.<sup>1</sup> Municipalities have attempted to bypass these charges through various

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1. The basis for stranded cost recovery under a regulatory contract and under constitutional protection from government takings is examined in J. Gregory Sidak & Daniel F. Spulber, *Deregulatory Takings and Breach of the Regulatory Contract*, 71 N.Y.U. L. REV. 851 (1996). For a discussion of stranded costs in the natural gas and electric industries see Michael J. Doane & Michael A. Williams, *Competitive Entry into Regulated Monopoly Services and the Resulting Problem of Stranded Costs*, 3 HUME PAPERS ON PUBLIC POLICY, Autumn 1995, at 32.

approaches, including: (1) traditional municipalization through condemnation; (2) municipalization involving construction of duplicative or parallel facilities; (3) municipalization through annexation; and (4) municipalization through the provision of only minimal facilities, i.e., muni-lite. The municipalities allege that under the Federal Energy Regulatory Commission's (FERC) Order No. 888<sup>2</sup> they are not responsible for payments resulting from stranded costs because they could always have condemned the property. Thus, they claim that the utility could not have had a reasonable expectation of continuing to serve in the area. This article explores the municipalization bypass phenomenon and concludes that the FERC should adjust its policies to avoid this type of opportunistic behavior.

How do retail customers bypass the competition transition charge? FERC's Order No. 888 developed a "reasonable expectation" criterion for the recovery of stranded costs from retail-turned-wholesale customers. The reasonable expectation approach represents an efficient means of addressing contractual change in wholesale power markets that is consistent with common law remedies for breach of private contract that protect buyer and seller expectations. However, while the FERC proceeded with laudable intentions and applied the correct economic approach to contractual expectations, the reasonable expectation standard may be subject to legal interpretations that depart from the economic expectations of utilities. Further refinement of the reasonable expectation criterion directed against so-called "sham transactions" may be necessary to rule out bypass of transition charges.

Municipalities, representing retail customers within their boundaries, can become wholesale intermediaries. The municipalities purchase commodity power from a lower cost source and seek an order from the FERC that the incumbent utility "wheel" that power over its transmission facilities to the municipality.<sup>3</sup> The municipalities then have an incentive to assert that the expectations of incumbent utilities should be substantially lower than the utilities claim, because the municipalities could have condemned the utility's distribution facilities for compensation equal to the book value of the facilities (rather than their market value). Thus, the retail customers avoid competition transition charges, and the municipality need only compensate the incumbent utility for the expected return that it would have obtained were its facilities to be condemned. Using this logic, any wholesale intermediary can enter to serve retail customers and propose that the utility's reasonable expectations should be lowered because retail customers could have bypassed the utility through cogeneration, self-generation, or the construction of new transmission inter-ties. Were such argu-

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2. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 61 Fed. Reg. 21,540 (1996) (codified at 18 C.F.R. pts. 35, 385) [hereinafter Order No. 888].

3. Applications for wheeling orders are slowly giving way to proceedings involving various "open access" tariffs that Order No. 888 required utilities to file with the FERC. When a wheeling order is issued, the FERC entertains a subsequent stranded cost proceeding in which it determines the amount of stranded costs the utility will incur as a result of the loss of retail customers. Order No. 888 states the FERC's commitment to utility recovery of stranded costs.

ments to be upheld, the reasonable expectation standard would have little practical value in determining the incumbent utility's economic expectations.

Because transition charges are typically assessed as distribution surcharges, there are incentives to avoid the charges through bypassing not just the merchant function of the incumbent utility, but the distribution system as well. The potential inefficiencies created by such bypass are evident. Duplicative distribution facilities are created not because they can be operated at lower cost than the incumbent or because additional capacity is needed. Rather, the avoidance of distribution surcharges makes the creation of alternative facilities economically feasible. This is a potentially difficult problem that has prompted calls for exit charges or competitively neutral end-user charges imposed on wholesale intermediaries.

This article addresses the two means of avoiding competition transition charges: municipalization and transmission bypass. We begin, in Section II, by reviewing some of the municipalization decisions. We consider proposals by municipalities to supply power with minimal facilities. We then review cases of municipalization with a duplicative distribution system or substation by examining opportunism and contract renegotiation. In Section III, we consider the FERC's "reasonable expectation" criterion for stranded costs recovery and consider what impact the possibility of condemnation by municipalities has on the expectation interests of incumbent utilities. In Section IV, we examine the potential for uneconomic bypass in the context of the changing structure of the electric power industry. We present our conclusions in Section V.

## II. MUNICIPALIZATION CASES IN ELECTRIC POWER

Table 1 summarizes the municipalization arrangements that have been proposed to date.<sup>4</sup> Of the thirty-nine proposals, thirteen involve traditional municipalization, five involve duplicative or parallel construction (or the acquisition of a duplicative distribution system or substation), five involve annexation, six involve muni-lite, one involves federal approval, and nine remain undecided with respect to the particular municipalization approach.

Municipalities have abandoned attempts to condemn the utility's distribution systems in ten of the forty proposed efforts because of costly condemnation requirements, voter disapproval, or both. Efforts to finalize municipalization have been completed in two cases, and the FERC has directed the utility to provide transmission service to the municipality in two cases (Cleveland, Ohio, and Suffolk County, New York). In one case (Palm Springs, California), the FERC denied the municipality's request for transmission service. In the majority of cases, however, implementation efforts are "in process" or "on hold," as parties await further information on the cost and benefits of the proposed projects.

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4. The information contained in Table 1 is derived, in part, from EDISON ELECTRIC INST., STATUS REPORT ON UTILITY MUNICIPALIZATION AND BYPASS ACTIVITIES (4th ed. 1997).

TABLE 1.  
MUNICIPALIZATION PROPOSALS

STATE CITY/CITIES	BYPASS PROPOSAL
California	
Culver City	Muni-lite Status: Defeated
Modesto	Municipalization via Irrigation District Status: On-hold (proposed settlement)
Palm Springs	Muni-lite Status: In Process (request for FERC rehearing)
San Francisco	Traditional Municipalization Status: Abandoned
Victorville	Muni-lite Status: Abandoned
Florida	
Dade County	Traditional Municipalization Status: Defeated
Illinois	
Evanston	Traditional municipalization Status: Defeated
Kansas	
Beloit	Municipalization by Annexation Status: Defeated
Kansas City	Municipalization by Annexation Status: In Process
Maine	
Jay	Traditional Municipalization or Muni-lite Status: On-hold
Westbrook, Norway, Old Orchid Beach	Traditional Municipalization or Muni-lite Status: On-hold
Michigan	
Alma	Parallel Municipalization Status: On-hold
Romeo	Traditional Municipalization Status: On-hold
Missouri	
Kirkwood	Traditional Municipalization Status: On-hold
New Hampshire	
Dover	Muni-lite Status: In Process

STATE CITY/CITIES	BYPASS PROPOSAL
New Jersey	
Aberdeen	Parallel Municipalization Status: Defeated
Monroe	Parallel Municipalization Status: Defeated
Montclair	Traditional Municipalization or Muni-lite Status: On-hold
Salem	Parallel Municipalization Status: On-hold
New Mexico	
Las Cruces	Traditional Municipalization Status: In Process
New York	
Elmira	Traditional Municipalization Status: In Process
Glens Falls	Traditional Municipalization or Muni-lite Status: In Process
Norwich	Traditional Municipalization Status: Defeated
Ogdensburg	Traditional Municipalization or Muni-lite Status: In Process
Riverhead	Traditional Municipalization Status: On-hold
St. Lawrence and Franklin Counties	Municipalization by Annexation Status: On-hold
Suffolk County	Muni-Lite Status: The FERC issued a proposed order directing Long Island Lighting Co. to provide transmission services to Suffolk.
Union	Undecided Status: Unknown
North Carolina	
Huntsville	Municipalization by Annexation Status: Defeated
Ohio	
Brook Park	Traditional Municipalization Status: On-Hold
Cleveland	Municipalization by Annexation Status: The FERC directed Cleveland Electric Illuminating to provide transmission service to Cleveland Public Power.
Clyde	Parallel Municipalization Status: Completed
Toledo	Traditional Municipalization or Muni-Lite Status: In Process
Oklahoma	
Broken Arrow	Traditional Municipalization Status: Completed
Pennsylvania	
Tarentum	Traditional Municipalization Status: In Process

STATE CITY/CITIES	BYPASS PROPOSAL
South Carolina	
Columbia	Various Alternatives Status: In Process
Darlington	Traditional Municipalization / possible Muni-lite Status: Defeated
Virginia	
Falls Church	Muni-Lite Status: On-hold (possible re-evaluation)
Department of Defense	Municipalization by Federal Approval Status: Defeated

In this section, we review economic aspects of the nontraditional municipalization proposals—"muni-lite", the building or acquiring of a duplicative distribution system or substation, and municipalization through annexation—as these approaches are attempts to evade transition cost payments through reliance on FERC's reasonable expectation criterion.

A. *Proposals by Municipalities to Supply Power While Owning Only Minimal Facilities—"Muni-Lite"*

1. Palm Springs, California

The City of Palm Springs (Palm Springs or City) is a political subdivision of the State of California and as such a chartered municipal corporation. Palm Springs has owned and operated the Palm Springs Electrical System (PSES) for thirteen years. The PSES includes three generating plants and a 12 kilovolt (kV) distribution system which allows the City to provide retail service to municipal facilities and a limited number of other customers.<sup>5</sup> Palm Springs sells surplus power to Southern California Edison and acquires from Edison standby electric service. The present load of the PSES is 7900 megawatthours (MWh) per year with peak demands of 1.55 MW and 1.30 MW in the summer and winter, respectively.

In the Palm Springs area, Edison owns and operates transmission, sub-transmission, and distribution facilities. Palm Springs granted Edison a franchise to construct, install, and operate such facilities "for transmitting and distributing electricity for any and all purposes . . . in, along, across, upon, over, and under the streets within the City of Palm Springs."<sup>6</sup> Edison provides retail electric service to most of the electric consumers located within the Palm Springs city limits.

Palm Springs requested that Edison deliver electric power from PSES power supply resources to multiple, low-voltage points of receipt. The proposal is that at these receipt points, newly installed City-owned meters

5. In addition to municipal facilities, the PSES provides retail service to the County of Riverside, an airline service provider at the municipal airport, the Federal Aviation Administration, and various airlines which utilize the municipal airport.

6. *Application of City of Palm Springs, California, for an Order Requiring Transmission Service Under Section 211 of the Federal Power Act*, F.E.R.C. Docket No. TX96-7-000, at 18 (1996) [hereinafter *Application*].

would be “interposed between Edison’s system and the facilities of all retail customers within the territorial boundaries of Palms Springs choosing to receive electric service from the City.”<sup>7</sup> In sum, Palm Springs would be a municipal utility consisting solely of electric meters, i.e., a “muni-lite”. Based on presentations by prospective power suppliers (Enova, Enron, Illinova, PacifiCorp, and Portland General Electric (PGE)), the City intends to select a partner with which to plan for the expanded needs of the PSES. These needs include power supply, ancillary services, transmission service arrangements, metering, billing, customer service, etc. Palm Springs estimates that the electrical load of the new PSES initially will be 600,000 MWh per year with a peak demand of 150 MW. This represents a one-hundred-fold increase in PSES’s capacity.

Palm Springs argues that it could provide retail electric service “at rates significantly lower than those of Edison by acquiring the Edison system inside the City’s limits, obtaining various wholesale power supply at conservatively estimated rates and replacing Edison as the sole supplier of retail electric service in the City.”<sup>8</sup> In lieu of condemnation, Palm Springs states it “wishes to expand the PSES by constructing only the minimal additional facilities necessary to measure and deliver its electric power and energy in connection with the services sought hereby.”<sup>9</sup> Palm Springs’ application also says, “the City’s plan for expansion of the PSES, if successful, will replace the existing monopoly on retail electric service in Palm Springs with competition between Edison and the City for each and every electric customer in Palm Springs.”<sup>10</sup>

The success of Palm Springs’ proposal rests on the price it pays Edison for transmission and distribution services. Palm Springs requests that charges for usage of distribution facilities be based on “system-wide distribution costs” and that Edison’s transmission costs “properly allocable to Palm Springs should be recovered through a transmission rate based on average transmission costs, allocated to Palm Springs based on its load ratio share of system wide-coincident peak demand.”<sup>11</sup> The City’s rationale for expanding the PSES in this way is that it avoids the stranded cost payments it would otherwise make to Edison. The City’s application states:

The Commission should determine whether Edison is entitled to recover any stranded costs in its rate for transmission service to the City. The Commission’s determination should preempt any application of a competition transition charge which might otherwise be authorized by the CPUC with respect to the City or its electric customers. The Commission should find Edison can have no reasonable expectation of protection against municipal competition under California law.<sup>12</sup>

In sum, Palm Springs asserts the FERC has jurisdiction over stranded cost recovery for municipal wholesale customers, but since the threat of municipi-

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7. *Id.* Executive Summary at 2.

8. *Id.* at 6.

9. *Id.* at 6.

10. *Id.* at 7 (emphasis in original).

11. *Application, supra* note 6, at 93-94.

12. *Application, supra* note 6, at 94.

palization has long existed, the "reasonable expectation standard" for cost recovery cannot be met.

The FERC found that the Palm Springs proposal did not meet the statutory requirements and was not in the public interest.<sup>13</sup> The FERC ruled that since Edison owned all of the transmission and distribution facilities, with the exception of the one 12 kV line owned by Palm Springs, the proposal by Palm Springs did not satisfy the requirements of section 212(h)(2)(B). The Commission stated that the "interposition of unnecessary, duplicate meters does not . . . constitute ownership or control of transmission or distribution facilities . . . within the meaning of section 212(h)(2)(B)."<sup>14</sup>

Even more importantly, the majority found that the proposal was against the public interest. The opinion states that the Palm Springs proposal appeared to be a means of avoiding payment for any stranded costs, and if approved, the proposal could disrupt the ongoing restructuring efforts of the California PUC.<sup>15</sup>

In August 1996, Palm Springs requested rehearing, which the FERC granted for the purpose of further consideration. Final action has not yet been undertaken.

## 2. Falls Church, Virginia

The city of Falls Church (Falls Church or City) proposed leaving Virginia Power's retail service territory and setting up a municipal utility that owns only meters. The City expected that the plan would provide retail customers with a choice of power suppliers, and that rates would fall by at least eighteen percent.<sup>16</sup>

Virginia Power argued that the City would need to pay for the stranded costs, which would increase the total cost of the plan. Falls Church responded with the argument that Virginia Power did not meet the "reasonable expectation" test because the utility had received several suggestions by the City over the past twenty-two years indicating a possible intention to leave the Virginia Power system. These suggestions included notice of intent to issue a request for wholesale power supply proposals.<sup>17</sup>

## 3. Freedom Energy

A newly formed utility in New Hampshire, Freedom Energy, applied to the FERC for a wheeling order under sections 211 and 212 of the Federal Power Act. The New Hampshire Public Utility Commission ruled that Public Service Co. of New Hampshire (PSNH) did not have an exclusive franchise to serve retail customers, but told Freedom Energy to apply for

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13. *City of Palm Springs, Cal.*, 76 F.E.R.C. ¶ 61,127 (1996).

14. *Id.* at 61,703.

15. 76 F.E.R.C. ¶ 61,127, at 61,704.

16. *Virginia Power, Falls Church Debate Pros and Cons of City Forming a Muni*, ELECTRIC UTIL. WK., Oct. 30, 1995, at 18.

17. *Id.*



an order from the FERC confirming its eligibility to obtain wholesale transmission service.<sup>18</sup>

The Commission received responses from several utilities arguing that the proposal was a "sham" since Freedom Energy did not own or operate any facilities and did not have any customers.<sup>19</sup> In addition, unlike Palm Springs, Freedom Energy did not have any authority under state law to condemn property to construct its own facilities. The proposal was criticized for lacking much of the detail needed to determine Freedom Energy's plans, but it appeared to involve leasing customer power-receipt equipment and reselling the power at retail over PSNH's transmission lines. PSNH stated that "[i]f there ever was an entity seeking to engage in sham wholesale wheeling transactions, this is it."<sup>20</sup>

#### 4. Suffolk County, New York

The Suffolk County Electrical Agency (SCEA) was created in 1983 to purchase preference hydropower from the New York Power Authority (NYPA) for resale to all Suffolk County residential customers and certain industrial customers. The SCEA owns no generation, transmission or distribution facilities, and was formed only to reallocate the NYPA's Niagara preference hydropower. The Long Island Lighting Company (LILCO) provides the power to the SCEA's customers, pursuant to a Lease and Operating Agreement, and the billing for the residential customers.

The SCEA proposed to expand operations and filed with the FERC for a transmission order for an additional 300 MW of power, which is fifteen percent of the retail power currently served by LILCO. The proposal envisions that the SCEA will purchase customer-owned meters and transformers, with LILCO providing the transmission service, as well as billing and collection services, for at least ten years.<sup>21</sup>

The application was silent about stranded costs, but the SCEA previously claimed, in comments filed with the FERC, that utilities are not entitled to stranded costs. LILCO objects to the proposal on the grounds that the SCEA is not a genuine municipal utility and that the proposal represents the type of retail wheeling and sham wholesale transaction prohibited by the Federal Power Act.

On December 31, 1996, the FERC issued a proposed order directing LILCO to provide transmission services "to the extent necessary to accommodate [the] proposed sales of power to customers to which [SCEA] was providing electric service on the date of the enactment (October 24, 1992)

18. *A Newly Formed Utility in New Hampshire Wants FERC's Assurance*, INSIDE F.E.R.C., July 24, 1995, at 7.

19. *Utilities Slam New Hampshire Company's Plan As Sham Wheeling Deal*, INSIDE F.E.R.C., Aug. 28, 1995, at 8.

20. *Utilities See Enormous Stakes, Protest Freedom Energy Bid to Obtain Wheeling*, ELECTRIC UTIL. WK., Aug. 28, 1995, at 6.

21. *Application of the Suffolk County Electrical Agency for an Order Requiring Transmission Service Under § 211 of the Federal Power Act*, F.E.R.C. Docket No. TX96-4-000, at 12 (filed January 17, 1996). See also 61 Fed. Reg. 2808, 2812 (1996).

of the Energy Policy Act."<sup>22</sup> The proposed order established further procedures to establish the rates, terms, and conditions of such services. To the extent that the SCEA seeks to obtain transmission service to serve customers not eligible to receive service from the SCEA on October 24, 1992, the FERC stated that the SCEA must "show that it owns or controls 'transmission or distribution facilities' to the extent it seeks to arrange for service to customers to which it did not provide 'electric service' on the date of enactment of the Energy Policy Act."<sup>23</sup>

*B. Municipalization Through Building or Acquiring a Duplicative Distribution System or Substation*

1. Aberdeen, New Jersey

The city of Aberdeen, New Jersey (supported by the largest employer and power user in the city, Anchor Glass Container (Anchor)) proposed building a utility to operate parallel to Jersey Central Power & Light (JCP&L). Anchor estimated that municipalization would cost \$16 to \$19 million and could cut electricity costs by thirty percent.<sup>24</sup> The town council put the municipalization proposal on the ballot for the November 1995 elections.

During the months prior to the election, both JCP&L and the township hired consultants to analyze the initiative. The consultant for Aberdeen identified possible stranded cost recovery as a risk factor, but did not quantify it. The JCP&L consultant estimated that building the duplicate system would cost at least \$39 million, and that payment for stranded costs could reach \$4.3 million annually.

On November 7, 1995, the citizens of Aberdeen, New Jersey defeated the measure 3646 to 563. Subsequent to this defeat, Anchor closed its plant in Aberdeen. The plant manager first blamed falling glass sales, not the failed municipalization, for the plant closure.

2. Modesto Irrigation District

In November 1994, PG&E and Destec Power Services (Destec) entered into a transmission service agreement (known as the Control Area and Transmission Service Agreement, or "CATSA") that enables wholesale wheeling of electric power as permitted under the Federal Power Act. Under the agreement, Destec purchases electric power from identified generation sources, aggregates the power into pools, and sells it at wholesale. PG&E transmits Destec's power over its transmission network among designated transaction points.

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22. *Suffolk County Electrical Agency*, 77 F.E.R.C. ¶ 61,355, at 62,543 (1996). The FERC found that SCEA was "grandfathered" under the first portion of Section 212(h)(2)(B) of the Federal Power Act.

23. *Id.* at 62,550.

24. *Voters in New Jersey Town Reject Proposal To Build Parallel Utility to Jersey Central Power & Light*, *ELECTRIC UTIL. WK.*, Nov. 13, 1995, at 4.

In January 1996, Praxair, Inc., a retail customer of PG&E, sold an electric substation (known as the Linde Substation) to the Modesto Irrigation District.<sup>25</sup> Earlier, Praxair had acquired the substation to convert high-voltage electric power to a lower voltage for use in its manufacturing facilities. The Linde Substation is approximately 100 miles from Modesto's service territory.

Destec asserts that Modesto's acquisition of the Linde Substation creates a utility distribution system and transforms the substation from a *retail* to a *wholesale* point. Since Destec seeks to supply Praxair at the substation, it requested that PG&E provide transmission service (under the November 1994 transmission agreement) from its generation point to the substation.<sup>26</sup>

At the same time, given that the CPUC does not regulate Modesto's retail rates,<sup>27</sup> Destec/Modesto can induce Praxair to leave PG&E by undercutting the incumbent's retail price by the amount of the newly established competition transition charge. Statements by a Modesto representative confirm this approach:

The other big issue that is hanging over the restructuring process is what is sometimes called uneconomic assets or stranded costs, and that's the costs that are associated with a lot of things that probably wouldn't have been done if people had the ability to view into the future, the nuclear power contracts, some of the contracts with independent facilities, the windmills, some of those types of things. And part of the approach that the CPUC has taken up to now is that a hundred percent of those costs have to be paid by the customers before any savings can begin under direct access . . . . The alternative that we offer, under current law, there's no procedure in place to recover stranded costs on an investor-owned utility to irrigation district transaction.<sup>28</sup>

In sum, the substance of this transaction is a sale of power from Destec to Praxair through Modesto. That sale would be preferable to that of power purchased from PG&E because it would be cheaper by at least the transition charge that is required in PG&E's price. In light of this concern, PG&E requested a summary decision from the CPUC to institute an emergency charge immediately. On April 10, 1996, the CPUC voted four to one to impose an interim emergency charge on retail customers leaving an investor-owned service for municipal utilities, power marketers, or others.

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25. The Modesto Irrigation District was organized in 1887 to provide water to farmers. It began selling hydro power in the 1920s. Today it generates electricity using hydro, gas, and coal plants, and purchases power from San Francisco's Hetch Hetchy hydro-electric facility and other utilities. Modesto serves approximately 90,000 retail customers in contrast to PG&E which serves 4.4 million customers. As a municipal, Modesto qualifies for tax-exempt financing and is not obligated to purchase power from "qualifying facilities" under the Public Utility Regulatory Policies Act (PURPA) legislation. In 1995, Modesto's system average electric rate was 7.7 cents per kWh. PG&E's system average electric rate was 11.6 cents per kWh.

26. Modesto's connection to PG&E is governed by a 1988 interconnection agreement that specifies only one point of interconnection which is located adjacent to Modesto's retail service territory. See Interconnection Agreement Between Pacific Gas and Electric Company and Modesto Irrigation District.

27. Under California state law, the CPUC does not regulate the retail rates of irrigation districts.

28. Christopher Mayer, Presentation at the Oakdale City Council Meeting 16 (December 4, 1995).

In September 1996, PG&E and Destec entered into a settlement relating to the dispute over the proposed electric service by Modesto to Praxair and jointly asked the FERC to suspend its consideration of the proceeding.

### C. *Municipalization Through Annexation*

Cleveland Public Power (CPP) currently serves one-half of Cleveland's power demands, but seeks to expand its service to the entire city. CPP projects it will double its service area within the next five years as a result of a "rate advantage" it has over the incumbent supplier, Cleveland Electric Illuminating (CEI).

In July 1996, the FERC ruled that CEI is obligated to provide transmission service to CPP under the utility's current transmission agreement with CPP.<sup>29</sup> The FERC cited the fact that CPP had competed with CEI in the provision of retail services for decades, and CPP's request required no more than CEI fulfilling the terms of its prior, FERC-approved transmission agreement. The FERC stated that this would not constitute a "sham transaction" because CPP intends to deliver power to its customers using its own transmission line. CEI's request for stranded cost recovery was dismissed because it was filed prior to the issuance of Order No. 888. However, the FERC ruled CEI may file for stranded cost recovery in a separate proceeding.

### D. *Summary*

It is instructive to review the FERC's rulings in the three municipalization cases it has reviewed to date. In *Palm Springs* the FERC found redundant meters do not constitute sufficient facilities to warrant transmission service under the Federal Policy Act. Moreover, the FERC recognized a "sham wholesale transaction" would be at odds with the state commission's attempt to impose direct access and retail choice.

In *Cleveland Electric Illuminating Company*, the FERC ordered transmission service, ruling CPP would not violate the "sham transaction" provision of the Act since it had previously received transmission service from CEI.

In *Suffolk County*, the FERC ruled that the mere fact the SCEA "does not itself currently own or control transmission or distribution facilities, and is a 'paper' entity, cannot, in our opinion, stand as an automatic disqualifier to Commission-ordered transmission service under sections 211 and 212 of the FPA."<sup>30</sup> The proposed order, in effect, allowed Suffolk to "grandfather" its requested transmission service to those eligible for services as of the enactment of the Energy Policy Act. As was the case in *Cleveland Electric Illuminating Company*, the FERC deferred issues related to the pricing of the requested transmission service. While the Proposed Order requires Suffolk to fully and fairly compensate LILCO for the transmission services it would receive, it does not explicitly address

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29. *Cleveland Electric Illuminating Co.*, 76 F.E.R.C. ¶ 61,115 (1996).

30. 77 F.E.R.C. ¶ 61,355, at 62,549.

LILCO's stranded costs and the extent to which those costs would be recovered under the reasonable expectation criterion.

In sum, the FERC's rulings to date have not recognized two important aspects of the regulatory contract as they pertain to municipalization and bypass. The first relates to the interpretation and application of the reasonable expectation criterion. The criterion examines the *likelihood* of the utility serving the end-user under its exclusive franchise—not the ability of the municipality to initiate a condemnation proceeding. The second aspect of the FERC's decision-making relates to the pricing of transmission services so as to achieve the dual goals of promoting economic efficiency and mitigating the avoidance of competition transition charges. The FERC's decision to separately address pricing and stranded cost recovery issues creates opportunities for uneconomic bypass and an abrogation of the regulatory contract. The reasonable expectation criterion and incentives for bypass are the subject of the next two sections.

### III. THE FERC'S REASONABLE EXPECTATIONS CRITERION

The expectation interests of electric utilities are the expected net-revenue streams under regulation. FERC Order No. 888 states:

The opportunity for extra-contractual wholesale stranded cost recovery is allowed for only a discrete set of requirements contracts for which the utility can demonstrate that it had a reasonable expectation of continuing service, as well as for retail-turned-wholesale situations in which the utility satisfies the necessary evidentiary criteria.<sup>31</sup>

Assessment of expected net-revenues requires an evaluation of contractual obligations and expectations about regulatory policies, as well as price and cost information. The FERC opened the door to protracted discussion by stating that the question of whether a utility had a reasonable expectation of serving a customer and for how long "will be determined on a case-by-case basis, and will depend on all of the facts and circumstances."<sup>32</sup> The FERC concluded that the reasonable expectation standard could be applied even to cases where a utility had been making wholesale requirements sales that involved another utility transporting the power to the final customer.<sup>33</sup> Furthermore, the FERC found that the "existence of a notice provision in a contract creates a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the specified period."<sup>34</sup> In the case of a retail-turned-wholesale customer, the FERC required the utility to "demonstrate that it incurred such costs based on a reasonable expectation that the retail-turned-wholesale customer would continue to receive bundled retail service."<sup>35</sup> The role of the regulatory contract in determining expectations is emphasized by the FERC's addi-

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31. Order No. 888, *supra* note 2, at 21,630.

32. Order No. 888, *supra* note 2, at 21,653.

33. Order No. 888, *supra* note 2, at 21,653.

34. Order No. 888, *supra* note 2, at 21,653.

35. Order No. 888, *supra* note 2, at 21,653.

tional consideration of whether state law awarded exclusive territories and imposed a statutory obligation to serve.

In this section, we review the risk-sharing aspects of contracts in general and the effects of risk on the regulatory contract. We then consider the effects on a utility's expectations of the possibility of condemnation by a municipality.

#### *A. Risk Sharing and Contract Contingencies*

Transactions usually do not involve simultaneous performance, as with a simple exchange. Contracts are needed to handle the problems that may arise with the passage of time. Generally, there is a delay between the time the contract is entered into and the time that performance is completed. During this time there are often foreseen and unforeseen changes in the circumstances of the parties. The contract is designed to adjust the terms of the transaction to handle contingencies.

Contracts often provide a means of sharing risks between parties. By using co-payments or deductibles in insurance contracts, insured parties share the risks of loss with insurance companies. A forward contract between a buyer and a seller that sets a price for the exchange exposes both parties to some risk. The seller's costs may vary while the buyer's willingness to pay may change before the product or service is received.

To address uncertainty, contracts involve contingencies or *conditions*, so that the promises made in a contract may be contingent on some event or state of the world occurring. Thus, contractual performance may be tied to specific events, so that a failure to perform as promised is excused only if it can be shown that the event has not occurred. The verification of the conditions under which performance did or did not occur is an important part of monitoring contractual performance. The "cost-plus" contract is useful in situations where the costs of the seller are difficult to estimate in advance due to rapidly changing input costs or to the use of a new technology. This provides some protection for the seller by shifting some of these cost risks to the buyer. The fixed-price contract requires the buyer to monitor the performance of the contract's terms. Additional monitoring costs are imposed by cost-plus contracts since the buyer must monitor whether the costs were properly incurred according to the contract terms. Still other procurement contracts feature incentive schedules that reward the seller for product features or for cost efficiencies. Such contracts typically involve risk sharing between the parties and are designed to handle situations in which it is difficult to base contractual rewards on the other party's efforts, since those efforts are difficult either to observe or to verify. These types of contracts create incentives to improve performance.

Since it is costly to identify all contingencies and to write contracts that depend on many contingencies, contracts are of necessity "incomplete." That is, they do not spell out all possible contingencies and the associated performance that is expected. Since it is often at least as difficult to verify what events occurred, contracts often address those events that are more easily verified. Contract law plays an important role in reducing the costs

of contracting by making general rules for various types of events that may occur and specifying damages for breach of contract.

Remedies for breach of contract serve as a general contingency that reduces the costs of writing contracts and creates incentives for efficient breach decisions. Remedies thus help in the formation of efficient contracts. Damages for breach protect the *expectation interests* of the parties. Thus, if a party breaches a contract, the expectation damages payment provides compensation so that the other party is as well off as he would be had the contract been honored. Thus each party is assured of receiving the expected net benefits from the contract. If the contract has contingencies, expected benefits from the contract reflect the relative likelihood of those contingencies. Even in the absence of contract contingencies, the expectation remedy requires estimation of the value of the contract.

### *B. Risk Sharing and the Regulatory Contract*

The regulatory contract provides a means of sharing risks between the utility's shareholders and its ratepayers. By allowing the utility recovery of its costs plus a competitive rate of return, the ratepayers take on some of the risks of the utility. The utility is allowed to recover the costs of labor and fuel even though these may be subject to price fluctuations. The utility's recovery of its financing costs often is tied to the costs incurred in equity and debt financing. The utility's investors bear various risks. In particular, there is no guarantee that they will be successful in fully recovering the allowed rate of return. They commit funds to investment expenditures but are subject to variations in return as a consequence of changes in customer demand and technological change. In addition, the utility's investors bear some risks associated with the vagaries of the rate hearing process. To a certain extent, information about these risks is reflected in the utility's financing costs.

FERC Order No. 888 explicitly addresses the issue of risk and expectations. The Order agrees with some industry commentators that "while . . . there has always been some risk that a utility would lose a particular customer, in the past that risk was smaller."<sup>36</sup> Thus, the FERC observes "[i]t was not unreasonable for the utility to plan to continue serving the needs of its wholesale requirements customers and retail customers, and for those customers to expect the utility to plan to meet future customer needs."<sup>37</sup> Changes in statutes and regulations governing the electric power industry have altered expectations, because "[w]ith the new open access, the risk of losing a customer is radically increased."<sup>38</sup> Therefore, the FERC recognizes that net-revenue expectations can differ significantly before and after the advent of open access.

In addition to the regulatory contract, the utility enters into contracts with other parties subject to regulatory approval, notably contracts with

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36. Order No. 888, *supra* note 2, at 21,629.

37. Order No. 888, *supra* note 2, at 21,629.

38. Order No. 888, *supra* note 2, at 21,629.

fuel suppliers and wholesale customers. Regulators must approve the terms of the contract as prudent. By including the capitalized costs of supplier contracts in the rate base, the risks of these private contracts are included in the regulatory contract. For example, if an electric utility enters into a fuel contract with a supplier and the cost of that contract is included in the rate base, the costs and benefits of such a contract are part of the regulatory bargain. The ratepayers share the benefits or the costs if spot prices for the fuel happen to rise above or fall below the contract price.

The regulatory contract has an extended "performance" phase. The performance of the utility in meeting its service obligations is constantly monitored by its many customers and is subject to periodic review by regulatory commissions. Performance consists in the provision of generation, transmission, and distribution services to meet the obligation to serve. Moreover, the utility must abide by rate regulation, maintain quality and reliability of service, maintain existing facilities, and provide additional facilities as needed to meet demand. Even with the introduction of competition in electric power markets, it is usually proposed that some form of the regulatory contract will continue, with the utility carrying out an obligation to serve for a remaining set of "core" customers.

Many private contracts have contingencies. Similarly, the regulatory contract incorporates some contingencies through fuel-adjustment clauses and indexed price cap formulas. Regulators address some demand and cost contingencies on an ad hoc basis. For example, rates are adjusted through the rate hearing process to reflect demand growth, changes in variable costs, or additional capital expenditures. Some aspects of the regulatory contract are relatively rigid, such as the continuing obligation to serve. Moreover, rates are generally constant during the time periods between rate hearings.

The rate setting process at state regulatory commissions is generally a complicated procedure that represents a type of "cost-plus" contract. The regulated utility is promised an opportunity to earn its costs plus a "fair" rate of return to cover its cost of capital. The rate setting process is a means of determining the cost of service and the allowed rate of return to capital. The revenue requirement serves not only as a constraint on what the utility can charge its customers, but also as an allowed level of revenues in compensation for its service.

The costs of including all possible contingencies results in the regulatory contract being incomplete, as are most private contracts. The contract does not specify in detail all of the potential changes in market conditions or in the regulatory environment. Rather, it is a broad understanding of principles, such as the utility's obligation to serve and the opportunity to earn a competitive return on investment. In addition, the regulatory contract is a set of procedures that includes prudence reviews and adjustment mechanisms that address market change, such as rate hearings. The general understanding between the regulated firm and the regulatory authority is that the main components of the regulatory apparatus remain in place even though economic changes occur. The notion that the regulated utility



should be compensated for costs incurred in response to regulatory requirements is an implicit but important component of the regulatory contract.

A common argument against stranded cost recovery is that renegotiation of the regulatory contract has already occurred. Under this scenario, the regulatory authority and the utility have explicitly adjusted the allowed rate of return to compensate the utility's investors for the risk of deregulation itself and for the market risks that follow deregulation. Since a higher allowed rate of return permits faster cost recovery prior to deregulation, the argument continues, no additional provisions are needed for cost recovery after deregulation. For this argument to apply, several tests have to be met. Did the regulator and the utility specifically address the likelihood and substance of deregulation in rate hearings? Did the regulator increase the rate of return and was the increase intended to compensate for deregulatory risk? Did the increase result from a negotiated agreement between the regulator and the utility? Unless these conditions are satisfied, the regulatory contract cannot be said to have been renegotiated.

### C. *Condemnation, Competition and Reasonable Expectation*

As we have already observed, damage remedies in private contracts protect the parties' expectation interests. The FERC adopts a closely related standard of "revenues lost," using the following formula for calculating stranded costs S:

$$S = (R - V) \times L,$$

where R is the estimated revenue stream, V is the estimated market value of the released capacity, and L is the length of the obligation. The FERC estimates the change in the revenue stream (R-V) based on the average annual revenues from the departing customer for the three years prior to the customer's departure, less the average transmission-related revenues that would have been recovered from the departing customer over the same three years through the wholesale transmission tariff.<sup>39</sup> Use of an average of past revenues to determine expected net-revenues is chosen for convenience, to eliminate disputes over revenue projections and because the rates that produce the revenues were already approved by regulators.<sup>40</sup> The competitive market value estimate is determined by allowing the departing customer to choose between (1) the utility's estimate of revenues that could be received using the released capacity, and (2) the average annual cost to the customer of replacement capacity and associated energy based on the customer's new suppliers.<sup>41</sup> Finally, the length of obligation refers to the period of time that the utility reasonably could have expected to continue to serve the departing customer, and is determined through agreement between the parties or through litigation.

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39. Order No. 888, *supra* note 2, at 21,658.

40. Order No. 888, *supra* note 2, at 21,659.

41. Order No. 888, *supra* note 2, at 21,658.

Many factors can lower the returns of an investor-owned utility (IOU). A municipality may condemn the IOU's facilities and, in some cases, pay book value rather than market value for the property. If customers bypass the IOU, either through self-generation or purchases from power marketers, net-revenues will decline. Entry of competitive power producers with lower costs will lower the IOU's returns by lowering the market price of power. The key question is whether such events could reasonably be anticipated to occur, thus lowering the incumbent utility's "reasonable expectations."

Consider first the condemnation of the utility's facilities by a municipality. There are a number of reasons why such an event might reasonably be viewed as unlikely. First, municipalities are deterred from condemnation by the legal costs of the condemnation, the associated transactions costs, and the compensation costs of the condemnation. Second, the municipality incurs costs after condemning the facilities because the municipality must either operate the facilities, seek out a private operator or resell the assets. Each of these options entails varying amounts of administrative and transactions costs for the municipality. Third, condemnation proceedings establish a precedent that may affect the municipality's reputation in other existing and future contractual relationships. A reputation for such action would serve to deter future agreements and thus raise the cost of doing business for the municipality. Fourth, the majority of municipalization attempts ultimately are abandoned.

Acting rationally, a municipality weighs the costs of condemnation against potential benefits. The costs thus deter condemnation. Moreover, incentives for condemnation may hinge on regulatory change that might be difficult to foresee. Thus, if some types of condemnation depend on regulatory change, the likelihood of condemnation would be further reduced, since it would be weighted by the chance of regulatory change.

Even if condemnation were to lower the utility's returns drastically, because such a condemnation is unlikely, the possibility of its occurring would have little impact on expected returns. The *possibility* that an event may occur is, of course, fundamentally different from a certainty. The value of facilities after condemnation cannot be used to determine reasonable expectations without factoring in the likelihood that a condemnation would have occurred. Thus, in determining the reasonable expectation of the party whose facilities are condemned, the loss in value due to a condemnation must be weighted by the probability of that event occurring.

To illustrate the effect of such an occurrence on expectation, suppose that the expected net return from a contract in the absence of condemnation was equal to \$100. Then suppose that if a condemnation were to occur, the company could expect to recover compensation of only \$10. This does not mean that \$10 represents the company's expectations. Instead, "reasonable expectation" must take into account the likelihood of the condemnation. Suppose, for purposes of illustration, that condemnations happen only 1% of the time. Then, the company's reasonable expectation, taking into account the possibility of condemnation, is:

$$\text{Reasonable expectation} = .99 \times 100 + .01 \times 10 = \$99.10.$$

The implication is clear: the unlikely event has little effect on expected value, even if that event entails a significant loss.

Indeed, the takeover of utility facilities by municipalities is an extremely rare occurrence. To get some idea of the likelihood of municipalization, consider the experience of the post World War II period. In 1946 there were 2068 electric municipal systems while a half-century later, there were only 1866 electric municipal utilities in operation. In the period 1947 to 1996, only 125 new electric municipal systems were formed. In comparison, the 1987 Bureau of the Census identifies 83,000 governments below the state level, of which 19,200 are municipal governments.<sup>42</sup> In addition, it identifies 3042 county governments, 16,691 township governments, and 29,532 special district governments. Many instances of municipalization are carried out by entities that are not municipal governments, such as the irrigation districts in California. To pick a conservative estimate of the number of governments, suppose that we confine our attention to the 19,200 municipal governments, less the 2068 that already had municipal electrical systems in 1946. This leaves 17,132 municipalities that did not have electrical systems. Then, given that 125 new municipal systems are formed, the likelihood of such an occurrence is  $125/17,132 = .0073$ , which is less than one percent. If more types of governments are included, the likelihood of condemnation becomes even smaller.

Similar reasoning applies to other forms of bypass, such as customers bypassing transmission to take advantage of regulatory change, or customers pursuing self-generation of power. For a utility customer to undertake bypass entails transactions and facilities costs. Undertaking self-generation requires incurring the cost of establishing and operating the facilities. If the customer does not have an incentive to bypass under existing regulation, the likelihood of a regulatory change occurring that will alter the incentive to bypass must be taken into account in determining the utility's expected returns. Prior to statutory and regulatory changes such bypass was relatively infrequent. Again, if these events are unlikely, the effect on reasonable expectations is negligible.

#### IV. BYPASS AND OPPORTUNISTIC BEHAVIOR

Bypass refers to replacement of the services of incumbent utilities by competing alternatives as a consequence of regulatory restrictions on incumbents and removal of entry barriers. Such bypass is likely to be efficient if it results from market decisions of customers and unfettered competition between incumbents and entrants. However, bypass is likely to be inefficient if it results from incumbent regulatory burdens on utilities or regulatory distortions of market prices.

The structural changes in the electric power industry represent fundamental changes in the regulatory contract. The bypass of IOU generation

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42. BUREAU OF THE CENSUS, U.S. DEP'T OF COMMERCE, GOVERNMENTS FINANCE AND EMPLOYMENT CLASSIFICATION MANUAL 13 (1992).

facilities, open access to transmission facilities and eventually to distribution facilities, and the projected erosion of the IOU merchant function reasonably can be expected to result in reduced earnings for the IOUs. Thus, competition and changes in regulatory policy may create substantial stranded investment for regulated firms.

Vertically integrated electric utilities supply four broad classes of services each of which are subject to bypass: generation, transmission, distribution, and merchant services. Regulators are exerting pressure on these utilities to separate both generation and merchant services from transmission and distribution. The entry of lower cost generation sources and open access transmission and distribution is likely to idle inefficient generation facilities. Deregulation causes companies with transmission and distribution systems increasingly to transmit power for others, so that the transportation function becomes separate from the merchant function. Brokers and other intermediaries are entering the electric power markets. The electric power industry is developing a structure that corresponds more closely to manufacturing, wholesaling, and retailing. The marketing affiliates of companies that have transmission and distribution facilities will compete with brokers and other market makers that do not possess such facilities.

#### A. *Competition and Bypass*

Traditionally, vertically integrated utilities have generated and transmitted the bulk of electric power. The 244 IOUs are the primary providers of generation and transmission services, even though their number is a small fraction of the total number of electric utilities in the U.S.<sup>43</sup> The IOUs provide almost four-fifths of total U.S. electricity industry power generation and over 80% of total sales revenues.<sup>44</sup> In addition, they have over three-quarters of total electricity industry installed generating capacity.<sup>45</sup> The IOUs serve over three-quarters of the approximately 118 million ultimate customers of the industry, serving approximately the same share of total customers in the residential, commercial and industrial categories.<sup>46</sup> The ownership of the remaining 3,199 electric utilities breaks down as follows: 10 federal utilities, 2014 municipal or other publicly owned utilities, and 931 rural electric cooperatives.<sup>47</sup> Fewer than 1000 of the utilities in the U.S. are engaged in power generation; most are distribution utilities.<sup>48</sup>

Annual generation construction expenditures in current dollars rose steadily from the early 1970s until peaking at about \$25 billion in 1982, whereupon they began a steady decline into the late 1980s. They have

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43. ENERGY INFO. ADMIN., DOE/EIA-0348 (95), ANNUAL ENERGY REVIEW 1995, at 10 (1996).

44. Based on EDISON ELECTRIC INST., STATISTICAL YEARBOOK OF THE ELECTRIC UTILITY INDUSTRY 1995, at 19 tbl. 12, 56 tbls. 56, 57 [hereinafter STATISTICAL YEARBOOK].

45. *Id.* at 8 tbl. 2.

46. *Id.* at 51 tbl. 47, 52 tbl. 48.

47. ENERGY INFO. ADMIN., DOE/EIA-0348 (95), *supra* note 43.

48. ENERGY INFO. ADMIN., DOE/EIA-0531(92), ELECTRIC TRADE IN THE UNITED STATES 1992, at 1 (1994).

since hovered around \$7 or \$8 billion a year.<sup>49</sup> Construction expenditures are but a fraction of generation expenses. Concern over stranded investment should further reduce construction expenditures.

The main development in the generation sector is the entry of non-utility generators (NUGs) (including industry co-generators), qualifying facilities (QFs) (whose power PURPA requires IOUs to purchase), independent power producers, and small power producers. NUGs accounted for 8.1% of the electric utility industry net summer capability.<sup>50</sup> Within ten years, purchases of power by electric utilities from NUGs soared from negligible levels prior to the early 1980s to more than 200 billion kWh.<sup>51</sup>

The IOUs provide more than three-quarters of the transmission lines in use in the electric utility industry.<sup>52</sup> There are over 670,000 circuit miles of electric line of 22 kV and above, of which over 540,000 are IOU capacity.<sup>53</sup> The transmission system continues to expand. During 1995, the IOUs added over 5,000 circuit miles of new transmission and distribution lines and spent over \$2.4 billion on expanding transmission capacity and another \$8 billion on increasing distribution capacity.<sup>54</sup>

As federal and state regulators seek open access to the transmission and distribution facilities of the incumbent utilities, the extent to which the IOUs will recover the cost of providing unbundled electricity transportation services depends on how regulators determine rates for these services and what other service requirements they place on IOUs. The productive facilities of IOUs established to meet regulatory requirements may not be well suited to competitive conditions and changing customer requirements and may be technologically obsolete. As a consequence, competition can be expected to reduce the earnings of companies operating these facilities. Continuing regulatory restrictions on incumbent utilities can prevent the utilities from being competitive in generating, transmitting, distributing and marketing power. If earnings fall substantially, utilities will not recover all of the capital costs of the facilities. In some cases, if earnings fall below operating costs, facilities will be retired from service. Stranded investment can result in losses of shareholder value.

Investments of incumbent utilities can be stranded in many ways. First, investments in generation will be stranded if the facilities are not economically efficient in comparison with new, lower-cost entrants that are not subject to the same regulatory burdens faced by incumbents. Second, incumbent utilities will fail to recover the costs of contractual obligations to purchase power at above-market rates mandated by regulation. Third, the

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49. STATISTICAL YEARBOOK, *supra* note 44, at 70 tbl. 70.

50. ENERGY INFO. ADMIN., *supra* note 43, at 233.

51. ENERGY INFO. ADMIN., *supra* note 43, at 231.

52. This is calculated by comparing total circuit miles for electric lines of 22 kV and above for IOUs with those for the electric utility industry as a whole. See STATISTICAL YEARBOOK, *supra* note 44, at 83 tbl. 86, 84 tbl. 87.

53. STATISTICAL YEARBOOK, *supra* note 44, at 83 tbl. 86, 84 tbl. 87.

54. STATISTICAL YEARBOOK, *supra* note 44, at 70 tbl. 70.

transmission and distribution facilities of incumbent utilities will be bypassed by competitive suppliers if incumbent burdens prevent the IOUs from competitively pricing access to their facilities. Fourth, incumbent utilities will experience losses if transmission access pricing mandated by regulators does not cover costs.

In pursuing the laudable goal of encouraging a competitive wholesale market for bulk power, set by the Energy Policy Act, the FERC has unilaterally rewritten some of the terms of the regulatory contract. For example, some of the generation facilities of the incumbent IOUs may be displaced by more efficient independent power generators. FERC's open access policies are designed to foster a competitive wholesale market for power, with transmission at regulated rates on existing networks. Competition in wholesale power also creates incentives for retail customers and municipalities to become wholesale customers. These actions have important financial consequences for utilities and represent a change in the regulatory contract with the FERC. Their policies are closely related to the push by some state PUCs toward open access to utility distribution networks at the retail level. Thus, federal and state policies are leading to a fundamental change in the regulatory contract between utilities and state PUCs.

The FERC seeks to require "utilities to provide non-discriminatory open access transmission tariffs, while simultaneously resolving the extremely difficult issue of recovery of transition costs."<sup>55</sup> The FERC points out that:

[N]ew generation facilities can produce power on the grid at a cost of less than three cents per kWh to five cents per kWh, yet the costs for large plants constructed and installed over the last decade were typically in the range of four to seven cents per kWh for coal plants and nine to fifteen cents for nuclear plants.<sup>56</sup>

This suggests that generation facilities dedicated to providing power to wholesale power markets could be stranded as a consequence of competition. The FERC leaves state regulatory authorities the responsibility for costs stranded as a result of retail wheeling, holding the strong expectation that states will provide procedures for, and the full recovery of, legitimate and verifiable stranded costs. However, they generally will not allow the states to pass on these costs through charges on the interstate transmission system, suggesting that states apply a surcharge to state-jurisdictional rates for local distribution.<sup>57</sup> The debate over stranded cost recovery thus has spread to state legislatures and state PUCs.

There are mutual benefits for the regulated utility and ratepayers from opening the electric market to competition at the wholesale level. Thus, the regulatory contract can be renegotiated, making ratepayers better off without denying just compensation to the utility's investors. Competition will eliminate price distortions that cause economic inefficiencies. By eliminating cross subsidies, there will be lower prices to industrial and commer-

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55. Order No. 888, *supra* note 2, at 21,550.

56. Order No. 888, *supra* note 2, at 21,550.

57. Order No. 888, *supra* note 2, at 21,650.

cial customers. This will reduce incentives for inefficient bypass and costly investment in cogeneration systems that are less efficient than larger power plants. Competitive prices for power will encourage industrial and commercial electricity customers to make efficient decisions about conservation and capital investment in electrical equipment.

Deregulation will also lead to the elimination of hidden subsidies for inefficient activities such as DSM programs that IOUs have carried out that would never be done by a competitive firm. Imagine your local automobile dealer paying its customers to take the train rather than buying a car. In addition, legal mandates for inefficient contracts to purchase power at above market rates from qualifying facilities would be eliminated. Further, inefficient fuel contracts made to satisfy regulatory orders would not be consistent with a competitive market.

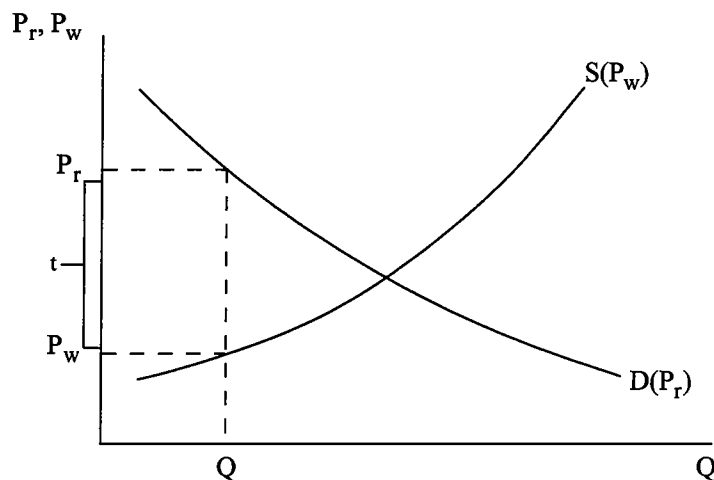
A competitive market in power also will allow variation in the reliability of power supplies. Companies with lower reliability requirements may opt for interruptible/curtailable electric power supplies, allowing more efficient use of generating and transmitting capacity. Deregulation of rates will permit companies to institute flexible pricing policies that respond more rapidly to changes in costs and market demand. This may result in improvements in peak and off-peak pricing structures.

Competition in retail and wholesale electric power markets will bring many benefits to consumers, reducing prices for many while increasing productive efficiency, innovation and product variety. These benefits will be enhanced through renegotiation of the regulatory contract with existing utilities. Established IOUs bring a number of important assets to the competitive market. They have already built significant electricity generation, transmission and distribution facilities. While many generating facilities may not be competitive with newer systems, others may have sufficiently low operating costs. It would be inefficient to strand these assets due to regulatory constraints when they continue to have economic value.

### *B. Inefficient Bypass and Transaction Costs*

In a properly functioning competitive market for electric power, the price spread between retail and wholesale prices should equal the transaction costs of retailing. These transaction costs include the returns to retail intermediation and the direct costs of managing transactions. The equilibrium price spread is shown in Figure 1. In the figure,  $P_r$  represents the retail price for power and  $P_w$  represents the wholesale price of power,  $Q$  is the quantity of power, and  $t$  is the equilibrium per-unit transaction cost of power. The supply of power on wholesale markets is  $Q = S(P_w)$  and the demand for power on retail markets is  $Q = D(P_r)$ . Intermediaries such as local distribution companies and marketers buy power wholesale and provide power on the retail market.

FIGURE 1  
THE MARKET EQUILIBRIUM RETAIL PRICE FOR POWER ( $P_r$ )  
AND WHOLESALE PRICE FOR POWER ( $P_w$ ) WHEN PER-  
UNIT TRANSACTION COST EQUALS  $t$ .



If the price spread is greater than the transaction costs of incumbents, say  $t^I$ , there is an opportunity for less efficient intermediaries to enter the market, with  $t^E > t^I$ . Thus, distortions in the price of power due to bypassable transition charges create opportunities for inefficient intermediaries, such as muni-lite transactions. Therefore, transmission charges that are incorporated in the wholesale price of power may provide a better means of recovering the transition costs, assuming that transmission itself will not be bypassed as a result of these charges. Alternatively, charges could be applied to the retail intermediaries themselves, on a per-unit sold basis, although absent legislative controls, such end user charges also may be subject to some types of bypass. What we wish to emphasize is that the retail-wholesale price spread should not be distorted. Otherwise, inefficient transactions such as muni-lite will proliferate, ultimately raising the total cost of distributing power to consumers.

### C. The Transmission Bypass Loophole

Collecting competition transition charges through transmission creates incentives to bypass transmission. Retail-turned-wholesale customers can avoid these charges by not seeking transmission from an incumbent utility. This is because Order No. 888 creates a bypass loophole by excluding from wholesale stranded costs those costs "that are exposed to nonrecovery when a retail customer or a newly-created wholesale power sales customer ceases to purchase power from the utility and does not use the utility's transmission system to reach a new generation supplier (e.g., through self-generation or use of another utility's transmission system)."<sup>58</sup> This creates

58. Order No. 888, *supra* note 2, at 21,646 n.718.



an incentive for these customers to invest in facilities in order to access competing transmission services, particularly for customers located near other service territories. The significance of transmission bypass is limited by the costs of connecting to competing facilities. The greater the level of transition cost charges, the wider the area in which customers will link up with competing transmission facilities.<sup>59</sup>

Such bypass of transmission to avoid competition transition charges is potentially inefficient because the construction of alternative transmission facilities is not motivated by existing capacity requirements. Rather the costs of construction are covered by cost savings from avoidance of competition transition charges. The result is higher total costs of transmission, thus leading to lowered economic efficiency. For this reason, transmission charges can fail to be competitively neutral without additional safeguards. The transmission bypass loophole has additional consequences because bypass can spread to other incumbent services.

Transmission bypass also entails increased transaction costs. Customers seeking to bypass incumbent utility transmission facilities must search for alternative sources of power and negotiate contracts to obtain power and transmission. In addition, construction of alternative transmission facilities requires customers to obtain construction services and negotiate for rights of way.

There is no clear solution to the transmission bypass loophole. One approach is an exit fee, such as the California Public Utilities Commission (CPUC) approved in California. The CPUC approved an interim competition transition charge to be applied to the average bills of large customers departing the Pacific Gas & Electric (PG&E) system before the beginning of retail competition.<sup>60</sup> The charge is based on PG&E's purchased power contracts and part of the company's generation-related revenue requirements.<sup>61</sup> The CPUC granted exemptions to customers engaging in self-generation and cogeneration, irrigation districts, certain power authorities, and federal preference power purchases.<sup>62</sup>

The application of a fee, such as that provisionally approved in California, may be necessary to close the transmission bypass loophole until the advent of retail competition. The fee is applied to avoid creating incentives for inefficient transmission bypass. As the electric power industry becomes increasingly decentralized, it becomes increasingly difficult to implement competitively neutral end user charges on final electric power customers. Whether such a measure is necessary depends on whether or not transmission bypass is determined to be a significant concern. Charges

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59. In the case where transmission lines are jointly-owned, a customer could potentially bypass the former supplier using the same transmission lines they were using before, but a different transmission service supplier. Under Order No. 888, in such situations, the former supplier may be denied stranded cost recovery even though the same transmission lines are being used to serve the customer. Order No. 888, *supra* note 2, at 21,633 n.615.

60. The start date for retail competition is January 1, 1998. See EDISON ELECTRIC INST., 3 RETAIL WHEELING AND RESTRUCTURING REPORT 55 (1996).

61. *Id.*

62. *Id.* at 57.

placed on transmission, perhaps supplemented by measures to address bypass, continue to be the preferred mechanism for recovery of stranded costs from retail-turned-wholesale customers during the transition to competition.

#### *D. Regulation and Bypass*

The structure of the electric power industry is changing significantly due to deregulation and market entry. Entry of competitors is providing alternatives to almost every activity of the IOUs. Whether these changes are efficient depends on whether regulatory intervention distorts market incentives.

The first major change in the industry is the entry of alternative power producers, creating the conditions for a competitive wholesale market for power. These sources of power compete with the generation facilities of the incumbent utility. Beginning in 1992, the generating capacity added by independent power producers (IPPs) exceeded the capacity added by the utilities.<sup>63</sup> There were nearly 1300 QFs by 1995 with a generating capacity of over 56,000 MW.<sup>64</sup> In addition to QFs, IPPs, which are generation companies without transmission or distribution facilities, entered the wholesale power market. Utilities organized affiliated power producers (APPs) to provide generating facilities whose capital investment would not be included in their rate base.

The power generated by the QFs, APPs, and IPPs is sent to customers using existing transmission and distribution facilities. At the same time, other power sources are connecting directly to industrial customers bypassing altogether the IOUs' generation, transmission, and distribution systems. These alternatives include self-generation of power, cogeneration, QFs' use of their own power, and purchases from other utilities. Incentives to bypass the existing transmission facilities of the incumbent create advantages for those entrants who can locate power plants so as to avoid transmission and distribution facilities even if adequate capacity is otherwise available.

Of even greater significance is the bypass of the incumbent utility's merchant function. Marketers and brokers intermediate between alternative sources of power generation without owning generation, transmission, or distribution facilities. Brokers coordinate transactions without purchasing power. Power marketers buy and sell capacity and energy and arrange for its transmission. Marketers are classified as public utilities under the Federal Power Act.<sup>65</sup> Upon request, the FERC generally grants to power marketers: "(1) a waiver of FERC regulations and annual Commission

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63. Bernard S. Black & Richard J. Pierce, Jr., *The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 COLUM. L. REV. 1339, 1349 n.25 (1993).

64. ENERGY INFO. ADMIN., *supra* note 43, at 96 tbl. 56.

65. *Citizens Energy Corp.*, 35 F.E.R.C. ¶ 61,198, at 61,453 (1986).

charges, (2) abbreviated filings, (3) blanket approvals, and (4) disclaimer of jurisdiction over brokering activities."<sup>66</sup>

Under a power marketing transaction, the IOU transmitting the power no longer takes title to the electric power. The power is still carried over the utilities' transmission and distribution systems under wholesale and retail wheeling arrangements. The power is sold directly to customers or purchased and resold by a broker. This development relegates the utility to being a transporter of power rather than a power merchant. The power marketers undertake the wholesale and retail functions previously held by the IOUs.

Reasoning by analogy to natural gas markets, the FERC maintains that "functional unbundling of wholesale services is necessary to implement non-discriminatory open access."<sup>67</sup> In the natural gas industry, FERC Order 636 requires pipelines to separate gas sales from transportation, thus allowing open access to pipeline transportation for natural gas producers and customers.<sup>68</sup> The FERC's objective is for utility transmission grids to serve as transportation systems for bulk power markets, thereby allowing customers and suppliers of power to create sales contracts for power that are independent of transmission providers.

Municipalization attempts and transmission bypass are outgrowths of changes in federal and state regulation which have opened wholesale power markets to competition with the promise of widespread retail market competition. Restructuring of retail markets has already begun in California and other states. If the price spread between wholesale and retail exceeds transaction costs, an arbitrage opportunity exists for potential market entrants. Companies can enter and compete with the merchant function of local distribution companies. These companies can act as intermediaries, buying wholesale and selling at retail, earning the price spread net of transaction costs, or dividing the returns to arbitrage with their customers.

Entry of intermediaries enhances economic efficiency when it lowers wholesale and retail transaction costs relative to incumbents. However, such entry may fail to be efficient if the returns to arbitrage are due to regulatory distortions of relative prices that create returns to shopping in different jurisdictions. If entrants are simply taking advantage of differences in federal regulation of wholesale power markets and retail regulation of retail power markets, the returns to entry are due to income redistribution rather than economic benefits from lower transaction costs. This suggests the need for coordination of federal and state efforts to deregulate wholesale and retail markets to take into account the economic incentives resulting from differences in wholesale and retail prices.

66. See FINANCE, REGULATION AND POWER SUPPLY POLICY GROUP, EDISON ELECTRIC INST., POWER MARKETERS YEARBOOK—1994 SALES, PURCHASES AND PROFILES 4 (1994).

67. Order No. 888, *supra* note 2, at 21,552.

68. For an analysis of the effects of open access on natural gas markets, see Michael J. Doane & Daniel F. Spulber, *Open Access and the Evolution of the U.S. Spot Market for Natural Gas*, 37 J.L. & ECON. 477 (1994).

Significant sources of distortions in the retail-wholesale price spread are the charges levied on retail customers by state utility commissions and subtle aspects of federal regulation of wholesale markets that enable wholesale customers to evade those charges. Certain states have recognized the need for competition transition charges to allow incumbent utilities to recover those costs incurred by the utilities to carry out regulatory obligations that may not be covered by market revenues. If retail customers must pay competition transition charges and wholesale customers can avoid them, there exists a strong incentive to find a means of purchasing power on the wholesale market. Put differently, the price spread between wholesale and retail will reflect not only transaction costs, but the additional competition transition charge.

The consequences of retail customers seeking reclassification as wholesale customers are twofold. First, the returns from avoiding the transition charges may create incentives for the potentially inefficient bypass of existing power merchants, resulting in investment in duplicative metering equipment and distribution facilities and higher transaction costs. Second, bypass of the competition transition charges will thwart the intent of legislatures and regulatory commissions to permit utilities to recover stranded costs, creating potentially crippling losses for incumbent utility investors and impairing the ability of utilities to carry out future regulatory obligations.

#### V. CONCLUSION

As in private contracts, the regulatory contract provides protection against opportunistic behavior. Utilities would not have invested in generation, transmission, and distribution facilities of the type used to carry out regulatory obligations in the absence of such safeguards. However, the regulatory contract is not a guarantee of a specific level of earnings. Instead, the regulatory contract protects the investment-backed expectation interest of utilities. As with damage remedies for breach of contract, the regulatory contract protects the expected net-revenues of regulated firms.

FERC's Order No. 888 recognized the need to recover stranded costs: "If a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, we believe that the utility is entitled to recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer."<sup>69</sup> The FERC considered the expectation interests of electric utilities in wholesale contracts through its reasonable expectation standard for recovery of stranded costs. Practically every state has considered deregulation of electric power and retail wheeling issues.<sup>70</sup> States such as California have

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69. Order No. 888, *supra* note 2, at 21,629. As the Order notes, "the opportunity for wholesale stranded cost recovery under this Rule is limited to utilities that provided sales of generation and transmission under wholesale requirements contracts, and to utilities that provided service to retail customers that convert to wholesale customer status." Order No. 888, *supra* note 2, at 21,630.

70. See EDISON ELECTRIC INST., *supra* note 60, at 3.

acknowledged the need for stranded cost recovery and devised competition transition charges to be placed on kilowatthours (KWh) used by consumers at the distribution level.<sup>71</sup> Being entitled to recover stranded costs is one thing, while achieving that recovery is quite another. The recovery process is likely to be complicated as some utility customers explore alternative ways of avoiding transition charges for stranded cost recovery.

By recognizing the need to recover stranded investment, the FERC created a context for the decisions of state regulatory commissions that will assist them in resisting short-sighted pressures to renunciate the regulatory contract. Opportunism will be reduced by the creation of competitively neutral mechanisms for the recovery of stranded costs. Properly addressing federal and state jurisdictional issues will reduce the possibility of opportunism, allowing the relative prices in wholesale and retail markets to reflect the economic costs of transactions.

However, recovery of stranded costs through competition transition charges is not sufficient to eliminate incentives for opportunistic behavior. Electric power customers have identified two possible means of evading these charges: through municipalization and through transmission bypass. As we have emphasized, if driven entirely by regulatory loopholes, both of these outcomes represent costly and inefficient bypass. To guarantee stranded cost recovery during the transition to competition while eliminating incentives for inefficient bypass, state and federal regulators should avoid creating these loopholes.

Incumbent IOUs will provide much of the transmission and distribution facilities to the competitive market. They bring expertise and experience obtained from operating these systems. Incumbent IOUs also provide the crucial management of the power grids required to operate a wholesale market for electric power. Achieving the full economic benefits of competition depends on the manner in which regulatory policy treats stranded investment. Regulators should avoid distorting economic incentives in emerging markets for electric power so that potential entrants, such as power generators, will make efficient investment decisions and electricity customers will make efficient purchasing decisions.

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71. The California legislature passed a restructuring bill in August 1996 (AB 1890) which provides for the recovery of a variety of generation-related stranded costs over an accelerated time frame through a non-bypassable "competition transition charge" (CTC) to be paid by all electricity consumers as direct access to sources of generation is phased-in over the next four years. A.B. 1890, 1996 Portion of 1995-96 Reg. Sess. (Cal. 1996).

