STATE OF MAINE
PUBLIC UTILITIES COMMISSION

In Re Market Power Study) **Docket No. 97-877**
)

FINAL REPORT

I. INTRODUCTION

Following enactment on May 29, 1997 of historic electric restructuring legislation,[1] the Legislature directed the Department of the Attorney General ("Department") and the Public Utilities Commission ("Commission") "to conduct a study of market power issues raised by the prospect of competition in the electric industry," and to provide "a final report of their findings and recommendations no later than December 1, 1998."[2] This report, presented to the Joint Standing Committee on Utilities and Energy jointly by the Department and the Commission, responds to that legislative mandate. The report includes specific legislative recommendations. Proposed draft legislation designed to implement those recommendations will follow.

A. The Statute

Maine's electric industry restructuring statute opens the State's retail electricity markets to competition as of March 1, 2000, enabling consumers to choose among competing energy providers. The underlying premise of the statute is that competitive markets result in higher quality products at lower prices. In addition to initiating retail choice, the new law:

- requires investor-owned utilities to divest most generation assets, while allowing them to retain transmission and distribution ("t&d") assets

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[1] P.L. 1997 ch. 316, codified at 35-A M.R.S.A. §§ 3201-3217.

[2] P.L. 1997 ch. 447 Part B §§ B-1, B-6.

- preserves state regulation of electricity delivery systems, i.e., t&d services

- permits regulated t&d companies to engage in retail marketing through unregulated affiliates, subject to a code of conduct and a market share limitation

- imposes a Renewable Portfolio Standard ("RPS"), requiring competitive providers to demonstrate that 30% of their supply portfolio derives from renewable resources (as defined)

- ensures the availability of default "standard offer" retail service for consumers who prefer not to select a competitive provider.

B. The Context

Electric industry restructuring initiatives are proceeding at the federal level and in numerous states in the United States. Internationally, restructuring is well advanced in several countries, including New Zealand, the United Kingdom and Norway. Because of the size and economic importance of the energy sector, these restructuring efforts are unprecedented both in their scale and in the scope of their economic implications.

Until relatively recently, it was generally accepted that competition was simply not feasible in an industry dominated by monopoly fiefdoms. Historically, the U.S. electric industry developed as a patchwork of isolated, vertically-integrated monopoly utility systems, each generating and distributing energy to retail customers in a discrete service territory. Retail rates were, and in most U.S. jurisdictions still are, subject to regulation by state Public Utilities Commissions. As interconnections between utility systems were forged to enhance reliability, and regional grids took shape, a wholesale market developed. Today, utilities purchase electricity in the wholesale market from other utilities and from independent energy producers. Interstate wholesale rates and transmission rates are subject to federal regulation, specifically by the Federal Energy Regulatory Commission ("FERC").

Maine and several other New England states (and numerous other states across the country) are opening retail markets to competition on varying schedules. At the same time, FERC is moving to introduce competition into wholesale markets. The agency now permits energy wholesalers to charge market-based rates if they can demonstrate that they do not possess, or have adequately mitigated, market power in the relevant market. The New England Power Pool ("NEPOOL"), the regional utility consortium, currently has an application pending before FERC for authority to charge market-based rates.

As wholesale and retail restructuring moves forward regionally and nationally, the shape and character of the industry will be altered in important respects:

- vertical integration will diminish as states mandate or encourage separation of generation and transmission, and new, independent generation facilities enter the market

- federal and state regulation of transmission and distribution will remain, reflecting the fact that proliferation of competing power delivery systems is impracticable

- rates for wholesale and retail energy will be determined by supply and demand in competitive markets.

C. The Study

The primary obstacle to the successful introduction of competition into electricity markets remains monopoly or oligopoly market power. Some economists predict that competitive markets will produce significantly lower prices for consumers,[3] as well as more generalized economic benefits. Others warn that these potential benefits will not be realized unless wholesale and retail markets are structured at the outset in such a way as to avoid control by a few large competitors.[4]

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[3] For example, one study predicts that Maine residential rates will drop by approximately 3¢/kwh (from 12.6 to 9.5¢), or 24%, in real dollars over the period 1996-2015. H. Chernoff & G. Sanchez, The Impact of Industry Restructuring on Electricity Rates, July 1998, Table ES.1.

[4] Consumer Union & Consumer Federation of America, The Residential Ratepayer Economics of Electric Utility Restructuring: Balancing All the Costs and Benefits, July 1998 at 49 (market power could disproportionately victimize residential consumers, raising prices).

Recognizing that market power poses a serious threat to the success of its restructuring initiative, the Legislature immediately followed enactment of the restructuring statute with passage of a law directing the Department and the Commission jointly to conduct a comprehensive study of market power issues. In particular, the Department and the Commission were directed to examine the following:

- the effects of altering the system of electric power dispatch from a cost-based to a bid-based system
- the potential for market concentration or horizontal market power
- the potential for vertical market power arising from the ownership or control of transmission and distribution systems by entities selling or marketing electric power
- the extent to which imbalances of supply and demand create opportunities for the unreasonable exercise of market power
- the significance of existing or potential transmission system constraints and the ownership and control of transmission ties
- the significance of the isolation of portions of the transmission and distribution grid from other portions of the grid, in particular from those portions of the grid currently controlled by NEPOOL
- the reasonable geographic areas and markets in which market power could be exercised
- the extent to which market power in relevant markets is within the scope of federal regulatory jurisdiction; and
- the approaches taken in other states to address market power issues.

Our report addresses each of these aspects of the problem of market power in an appropriate context. Specifically, the report is organized in four substantive parts: vertical market power issues (Part III); horizontal market power in New England (Part IV); horizontal market power in northern Maine (Part V); and market power in renewables (Part VI).

Broadly speaking, the purpose of this report is to assess the extent to which the persistence of market power in restructured markets is likely to frustrate statutory goals, and prevent Maine consumers from receiving the benefits of competition. Based on our assessment, in accordance with the legislative directive, we offer recommendations with respect to needed modifications and additions to the restructuring statute. Some aspects of market power are beyond Maine's jurisdictional reach. We therefore also identify and discuss issues which the Department and the Commission are addressing, or may address, in federal regulatory or court proceedings.

While we are confident that the analysis of market power issues offered below provides a sound basis for our legislative recommendations, it should be noted that our analysis is necessarily open to debate, and remains subject to adjustment in light of intervening developments. Many of the issues discussed are highly controversial. The structure of electricity markets in Maine and New England, and the rules governing and the conditions surrounding them, are evolving rapidly. Moreover, none of the issues discussed in this report has been litigated or adjudicated, and our joint analysis should not be viewed as binding in any respect on the Commission in the context of any pending or future proceeding.[5]

Before turning to the substance of our analysis, we provide a brief introduction to market power in electricity, and explain why existing antitrust law cannot by itself provide a sufficient remedy.

D. <u>Market Power in Electricity</u>

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[5] Parties to any pending or future proceeding at the Commission are entitled to full due process rights to test both the facts assumed and the analysis developed in this report. Moreover, it is entirely possible that intervening events may require adjustment of our factual or analytical conclusions. It is noteworthy that even as the final drafts of this report were in preparation, there were developments at FERC and in discussions among stakeholders in northern Maine which clearly hold significant implications for market power analysis.

Market power may be either horizontal or vertical. Horizontal and vertical market power both carry special risks in electricity markets, because of the nature of electricity as a commodity, because of prevailing market rules, and because of the necessary coexistence of competition and regulation in restructured markets.

Horizontal market power is the ability of a single dominant firm or group of dominant firms to profit by raising prices above competitive levels. The higher the market shares of the individual firms, and the smaller the number of firms competing in the market, the more the market will be subject to the exercise of horizontal market power, and the less consumers will receive the benefits of higher quality and lower price.

Horizontal market power in electricity may be subject to a greater degree of abuse than in other industries, for three reasons. First, electricity is the ultimate perishable commodity; it cannot be easily stored in large quantities, but must be produced for immediate consumption. Thus, supply generally cannot be shifted from one time period to another to remedy scarcity. Second, retail demand for electricity is relatively inelastic. This means that demand is generally unresponsive to price fluctuations, and is not easily shifted from one time period to another.[6]

Finally, costs of production vary widely among facilities and fuel types. To the extent they are competitive, supply-side bids into the spot market, which will be the primary wholesale price-setting mechanism in New England, will be based substantially on variable costs. Under prevailing market rules governing bid-based dispatch, each facility or block of power will be bid

[6] Demand elasticity is much greater in the industrial than in the residential sector. We believe that further study is warranted to determine whether specific legislative or regulatory initiatives could promote demand elasticity generally as a means to mitigate horizontal market power. Supplier prices at wholesale and retail can be disciplined to the extent that retail customers are enabled to react in real time to hourly price developments. This requires access to appropriate metering, communications and energy management (automated switches activated by price information) technologies. Enhanced access to off-grid generation sources would also be desirable. Finally, facilitating customer aggregation might promote demand elasticity, and would strengthen demand-side bargaining power. The Department and the Commission may offer recommendations in this regard at a later time.

into the market, and the bids ranked from lowest to highest, for dispatch in that order. All suppliers receive the price bid by the last increment of supply necessary to meet demand in a given hour. As a result, competition between a relatively small number of competitors at the margin may be critical in setting price.[7]

Vertical market power, in contrast, derives from a single firm's integrated presence at more than one level of commerce. A firm which combines generation or retail marketing of electric power with provision of t&d services is vertically integrated. Where a vertically integrated firm is a regulated monopolist at one level of commerce, as t&d companies are, it may possess an enhanced ability to project its monopoly power to another level. For example, a t&d company might possess the ability to confer advantage on its retail marketing affiliate by providing it with preferential treatment, or free or subsidized services. Such an exercise of vertical market power would enable the affiliate to compete unfairly, and might deter would-be competitors from entering and permit the affiliate to build a dominant position in the retail market.

E. <u>The Limits to Antitrust</u>

The options available to antitrust enforcement agencies to remedy vertical or horizontal market power in newly restructured markets are limited and often inadequate. In essence, there are only four opportunities for antitrust intervention. First, a proposed merger or acquisition which significantly increases horizontal concentration (and reduces competition) is subject to effective challenge under state or federal antitrust laws. Second, collusive agreements or combinations among competitors (<u>e.g</u>. price fixing) are illegal under antitrust law, and subject to both criminal and civil enforcement. Third, exclusionary conduct by a monopolist can be attacked

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[7] Current NEPOOL market rules allow only for supply-side bids. However, ISO-New England, Inc., which will operate the spot market, favors introduction of demand-side bidding to mitigate market power. The Commission and the Department support this initiative.

as a monopolization offense, though such cases are notoriously lengthy, cumbersome and difficult to prove. Finally, unfair methods of competition may be challenged under the Unfair Trade Practices Act.[8]

It remains that preexisting market power, short of monopoly, which is entrenched in the structure of the industry and exercised unilaterally, is beyond the reach of the antitrust laws. In view of the limitations of antitrust enforcement, it is essential that Maine ensure, as far as the reach of its jurisdiction will allow, that newly opened electric power markets are competitively structured on day one. If the wholesale generation market or the retail market embark on competition with highly concentrated structures, or structures otherwise susceptible to the exercise of market power, antitrust enforcers will have relatively limited remedial options, and consumers may well pay higher prices.

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[8] 10 M.R.S.A. §§ 1101 (contracts or combinations in restraint of trade), 1102 (monopolization offenses), 1102-A (mergers and acquisitions); 5 M.R.S.A. § 207 (unfair methods of competition). Each of these provisions has a federal counterpart.

II. EXECUTIVE SUMMARY

A. Vertical Market Power Issues

Vertical market power may be brought to bear in the electric power industry when a utility operates a monopoly interstate transmission system and also engages in business as a generator of energy (transmission-derived vertical market power); or when a local transmission and distribution company (t&d) is also a retail marketer of energy (distribution-related vertical market power). Such an integrated enterprise can exercise vertical market power in two principal ways: by affording preferential treatment to the competitive affiliate; and by shifting costs to the regulated entity. Vertical market power threatens the ultimate success of restructuring efforts by raising the barriers to entering newly competitive markets.

Maine has addressed transmission-derived vertical market power in the restructuring statute by requiring utilities to divest generation assets, thereby severing the link between generation and transmission. However, New England's electric grid spans six states, and its wholesale markets are therefore subject to federal jurisdiction. Although some voluntary divestitures have occurred, no other state in the region has mandated divestiture. Accordingly, Maine must to a large extent rely on federal remedies to combat vertical market power in these markets. The FERC has implemented open access transmission rules, and has approved the establishment of an independent system operator (ISO) to operate the New England grid. The Commission and the Department are actively engaged in proceedings at FERC in which vertical market power issues have arisen.

In contrast, Maine possesses plenary legislative jurisdiction to address distribution-related vertical market power, which affects retail markets. In the restructuring statute, the Legislature adopted a dual approach, enacting a code of conduct to police the relationship between the t&d and its marketing affiliate, and a provision limiting the market share attainable by the affiliate in the t&d service territory. This solution represented a compromise between the contending positions of the utilities, which opposed the market share limitation and aspects of the code of conduct, and the Commission, which advocated a complete ban on affiliate marketing in the t&d service territory.

A ban would have effectively eliminated the problem of vertical market power. The Commission and the Department continue to believe that a ban would be in the best interest of Maine’s consumers. We recognize, however, that the balance arrived at in the statute remains untested, and do not here advocate any fundamental change. Rather, we recommend limited modifications to tighten and enhance the effectiveness of the code of conduct and market share limitation.

B. Horizontal Market Power: New England

Horizontal market power is the ability of a single dominant firm or group of firms to profit by raising prices above competitive levels. An indicator of the extent to which a market is subject to horizontal market power is the size of individual market shares, and the overall level of market concentration.

Southern and central Maine form part of a regional New England wholesale electricity market, whose geographic boundaries are coextensive with the NEPOOL grid. Occasionally, smaller geographic markets, known as load pockets, may arise within the grid as a result of transmission constraints or outages. Northern Maine, a separate market, is analysed in a subsequent section of this report.

We use the Herfindahl-Hirschman Index (HHI) to estimate the level of concentration in New England electricity markets. The HHI is an indicator rather than an absolute measure of horizontal market power. Accordingly, we also review additional factors in our assessment. Specifically, we look at the responsiveness of the New England market to competitive forces, and the effect of new entry. The related tasks of estimating levels of concentration and analysing market power are complicated by the rapid pace of change in the New England electric industry in recent years.

The HHI for New England's wholesale energy market for summer 2000, allowing for new entry and out-of-region imports, shows a moderate level of concentration by federal standards, indicating a corresponding degree of market power. With two participants holding 50% of the market, and four over 60%, the market is subject to oligopoly control.

Computer simulations suggest that oligopoly control may pose a special danger in the context of New England's electricity spot market, which will function as the principal price-setting mechanism in the region. The market may be vulnerable to unilateral strategic behavior, or gaming, as well as collusive practices. Simulation results show that if market leaders engage in such manipulative behavior, wholesale clearing prices could rise by as much as an average of 10%.

Over the next decade, planned new entry is likely to increase competition in the New England market. In the short to medium term, market power is likely to remain problematic. However, New England's interstate wholesale markets are subject to federal jurisdiction. Maine's ability to address horizontal market power in this context through legislation is limited to the margin. We recommend a limited legislative measure focused on market power within a load pocket, i.e., an area within Maine temporarily isolated from the grid (and federal jurisdiction) by a transmission outage. Beyond this, the Commission and the Department have been, and will continue to be, active in representing the State's interest in promoting competitive regional markets before FERC.

C. Horizontal Market Power: Northern Maine

Northern Maine (Aroostook and parts of Penobscot and Washington Counties) is isolated from the New England grid, and functions electrically as part of the Canadian Maritime control area. It constitutes a separate geographic market for purposes of market power analysis.

The northern Maine wholesale energy market is highly concentrated, and subject to a corresponding degree of market power. The market is dominated by New Brunswick Power Corporation ("NBP"), which controls transmission access to northern Maine. NBP transmission is unsupervised by any regulatory authority, and NBP has set discriminatory rates, with the result that it has preferential access to the market. This transmission regime effectively excludes Hydro-Quebec from the market, as well as participants from New England and Nova Scotia.

In addition, there exists a transmission constraint which prevents firm power from flowing to northern Maine from New England. Moreover, the problem of market power is probably aggravated by the lack of access to a well-designed spot market. Finally, the prospect that new entry will increase competition in northern Maine is minimal.

Under these circumstances, the question whether retail choice in northern Maine should be postponed must be confronted. However, postponement should be a last resort. Other, less drastic remedies, which offer some promise of success, should be implemented in the first instance.

It now appears that the south-to-north constraint can be effectively eliminated by means of a contractual arrangement whereby NBP would supply back-up power and needed ancillary services to the four northern Maine t&d companies. NBP has stated its willingness to enter into such undertakings with the t&ds for a five-year term. We recommend legislation authorizing northern Maine t&ds to contract with NBP, and empowering the Commission to require that the purchased services be passed through to retail marketers at cost.

NBP and provincial New Brunswick authorities indicate that the current transmission regime is likely to be subjected to a legislative overhaul prior to the inauguration of retail choice in northern Maine. However, the timing of New Brunswick's restructuring remains uncertain. In the interim, it has been proposed that, as with the tie-line interruption and ancillary services, NBP should enter into contracts with northern Maine t&d companies to supply transmission services. It would be preferable if these services were supplied at NBP's lower "out" rate, rather than its higher "through" rate. Again, legislation is recommended. A meeting among the Commission, the Department, NBP and other parties has been scheduled to discuss these issues and arrangements.

The possible creation of a bulk power system administrator ("BPSA"), with or without a spot market, is also under discussion among the Commission, the Department and stakeholders. No consensus yet exists with regard to a workable concept in this area. Accordingly, legislation would be premature. The Commission and the Department will continue to monitor the development of a BPSA, and may offer additional recommendations later.

While transmission enhancements do not appear to be immediately essential to the competitive health of the northern Maine market, such enhancements would certainly be in the long-term interest of northern Maine consumers. The Commission and the Department will continue to monitor projects currently under study, will keep the Legislature informed, and may offer legislative recommendations in due course.

Finally, we recommend that, in view of the high level of market power in northern Maine, and the uncertain efficacy of available remedies, the Commission should be legislatively empowered to impose wholesale rate regulation to the full extent of the State's jurisdiction. We believe that the State possesses jurisdiction to regulate wholesale rates charged in northern Maine by generators located in Canada. Such regulatory power should be used only as a last resort to protect against market power, short of suspending retail choice. Even if never used, this option could provide a useful deterrent to market power abuse.

D. Market Power in Renewables

Maine's restructuring statute requires energy marketers to demonstrate, as a condition of licensing, that at least 30% of their supply portfolio for sales in Maine consists of renewable resources (as defined in the statute). This so-called Renewable Portfolio Standard ("RPS") creates a product market distinct from generic energy. Two geographic markets are analysed here for the presence of market power in renewables: New England and northern Maine.

The northern Maine market is highly concentrated; the New England market moderately so. In each case, a current condition of oversupply operates to negate market power. However, there is a potential for increased demand for renewables in the region, and the current oversupply may prove transitory.

If the supply picture tightens, market power could become problematic in both markets. The principal threat is that of vertical retail exclusion: participants holding high market shares in renewables would become the gatekeepers to Maine's retail energy markets, selecting or vetoing their retail competitors, and determining the prices at which they could compete. This threat is accentuated by a lack of flexible mechanisms for trading renewables, such as tradable credits, or a power exchange.

We recommend that the Commission be legislatively empowered to suspend or reduce the RPS in any section of the State on market power grounds.

III. VERTICAL MARKET POWER ISSUES

A. Summary

Vertical market power may be brought to bear in the electric power industry when a utility operates a monopoly interstate transmission system and also engages in business as a generator of energy (transmission-derived vertical market power); or when a local transmission and distribution company (t&d) is also a retail marketer of energy (distribution-related vertical market power). Such an integrated enterprise can exercise vertical market power in two principal ways: by affording preferential treatment to the competitive affiliate; and by shifting costs to the regulated entity. Vertical market power threatens the ultimate success of restructuring efforts by raising the barriers to entering newly competitive markets.

Maine has addressed transmission-derived vertical market power in the restructuring statute by requiring utilities to divest generation assets, thereby severing the link between generation and transmission. However, New England's electric grid spans six states, and its wholesale markets are therefore subject to federal jurisdiction. Although some voluntary divestitures have occurred, no other state in the region has mandated divestiture. Accordingly, Maine must to a large extent rely on federal remedies to combat vertical market power in these markets. The FERC has implemented open access transmission rules, and has approved the establishment of an independent system operator (ISO) to operate the New England grid. The Commission and the Department are actively engaged in proceedings at FERC in which vertical market power issues have arisen.

In contrast, Maine possesses plenary legislative jurisdiction to address distribution-related vertical market power, which affects retail markets. In the restructuring statute, the Legislature adopted a dual approach, enacting a code of conduct to police the relationship between the t&d and its marketing affiliate, and a provision limiting the market share attainable by the affiliate in the t&d service territory. This solution represented a compromise between the contending positions of the utilities, which opposed the market share limitation and aspects of the code of conduct, and the Commission, which advocated a complete ban on affiliate marketing in the t&d service territory.

A ban would have effectively eliminated the problem of vertical market power. The Commission and the Department continue to believe that a ban would be in the best interest of Maine’s consumers. We recognize, however, that the balance arrived at in the statute remains untested, and do not here advocate any fundamental change. Rather, we recommend limited modifications to tighten and enhance the effectiveness of the code of conduct and market share limitation.

B. Introduction

When an enterprise is active at more than one level of production, it is said to be vertically integrated. Vertical integration is often accompanied by gains in economic efficiency. The integrated firm can reduce transaction costs and supply or input costs, and realize economies of scale and scope, enabling it to offer lower prices to customers. Where the firm already faces healthy competition in both vertically-related markets in which it is active, therefore, vertical integration is likely to have a beneficial, procompetitive effect.

In other circumstances, however, vertical integration can give rise to vertical market power, conferring an ability to exact supracompetitive prices or profits. In particular, vertical market power can be brought to bear when an enterprise combines a regulated monopoly activity at one level of production with a competitive activity at another level. In the electric power industry, this situation may occur when (a) a utility operates a monopoly interstate transmission system and also engages in the business of generation and wholesale marketing of energy; or (b) a local transmission and distribution (t&d) company is also a retail marketer of energy.[9]

Vertical integration of a regulated transmission or distribution monopoly with a competitive marketer may enable the integrated enterprise to exercise market power in two ways: first, by affording the competitive affiliate preferential treatment; and second, by shifting costs from the competitive affiliate to the regulated entity.[10] Examples of such conduct range from blatant to subtle, and include, without limitation:

- tying purchases of competitive and regulated products

[9] Another instance of vertical market power in electricity arises from the conglomeration of a gas pipeline or coal production enterprise with electric generation facilities. For a discussion of vertical market power generally, see R. Binz & M. Frankena, Addressing Market Power: The Next Step In Electric Restructuring (1998) ("Binz & Frankena") at 27 -34.

[10] This analysis relies in part on the work of S. Morse & D. Howarth, MRW & Associates, reflected in their report, Vertical Market Power Issues and Electric Restructuring in Maine, July 31, 1998, compiled at the request of the Commission and the Department.

- provision of discriminatory prices or discounts to the affiliate
- according the affiliate preferential access to transmission or distribution facilities
- provision of lower quality or slower services to the affiliate's competitors
- sharing personnel, equipment and assets between regulated entity and affiliate at below market rates
- providing the affiliate preferential access to information
- using the regulated name and logo to benefit the affiliate
- understating the price of goods and services supplied to the affiliate
- inflating the price of goods and services supplied by the affiliate
- cross subsidies from regulated entity to affiliate.[11]

To the extent that the affiliate is permitted to benefit from preferential treatment, rivals can be disadvantaged, or even as a practical matter excluded. To the extent that a vertically integrated enterprise can successfully shift costs to the regulated entity, its affiliate may be enabled to compete unfairly on price at the expense of more efficient rivals. These affiliate abuses distort the competitive market, and could have the effect of enabling a less efficient, higher cost supplier to achieve dominance.[12] For customers, the result is higher prices on both counts: higher regulated prices as a result of improper cost allocation, and higher prices in the competitive market as a result of discriminatory practices, increased concentration and decreased competition.

In retail markets newly opened to competition, vertical market power has a further dimension. The affiliates of vertically integrated incumbent utilities are likely to enjoy additional significant advantages which could discourage competitive entry by other firms. Regardless of

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[11] The risk of cross-subsidization is to some degree reduced, though not eliminated, by performance-based regulation.

[12] Comment of the Staff of the Bureau of Economics of the Federal Trade Commission, May 29, 1998 ("FTC Maine Comment"), Maine PUC Docket No. 97 -877, 12.

name and logo use, the utility affiliate is likely to benefit, perhaps substantially, from goodwill developed over the years by the incumbent utility, as well as from customer inertia. The affiliate will also derive significant benefit from the free transfer of valuable employee expertise from the utility.[13]

In the aggregate, these manifestations of vertical market power constitute a formidable disincentive to entry by firms seeking to compete with the unregulated affiliate. If prospective retail competitors perceive that the utility affiliate can seize the lion's share of the market on the basis of incumbent advantages and abusive practices, they may well decline to enter the market at all. This risk may be especially serious in Maine, a small, largely rural state which offers only a modest return to prospective entrants. Vertical market power constitutes a significant threat to the success of Maine's restructuring efforts.

C. <u>Vertical Market Power In Practice</u>

Vertical market power is more than a theoretical construct. The historical record clearly demonstrates that vertically integrated enterprises possessing market power have used it to their advantage, often in spite of codes of conduct designed to prevent such abuses.

Vertical market power was the crux of the historic monopolization case brought by the U.S. Department of Justice ("DOJ") against AT&T. In that case, which resulted in a settlement under which AT&T was required to divest its local exchange operations, DOJ alleged that AT&T had inflated prices paid by regulated local telephone companies to competitive affiliates, engaged in cross-subsidization, and discriminated against competitors. Today, as it seeks to reenter local telephone markets, AT&T is itself the victim of alleged preferential practices engaged in by its

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[13] Competitors, on the other hand, would expect to pay finding or headhunting fees to recruit comparable expertise.

divested offspring.[14] In at least some cases, those incumbent local companies, despite federal requirements that they open their markets to competition, apparently have persisted in obstructing equal access to computer facilities essential to the ability of AT&T and other competitors to enter local telephone markets.[15]

In another instance drawn from the telecommunications industry, a 1990 FCC audit found that an unregulated NYNEX affiliate had inflated prices paid by the regulated entity for telephone equipment, resulting in overcharges totaling $118.5 million over a four-year period (1984 -88). Of this sum, $33.5 million had been passed on to customers under the FCC's interstate jurisdiction. The agency was able to secure a consent decree requiring NYNEX to refund this amount, and to pay a $1.4 million penalty. Years later, in 1997, the New York Public Service Commission ("NYPSC") finally concluded a long-running proceeding focused on the same transactions with an order requiring NYNEX to refund $53 million plus interest to New York customers. This order also found that NYNEX had underpriced subscriber lists provided to an unregulated affiliate, and required a further $30 million refund and other relief in that regard.[16]

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[14] E.g., Implementation of the Local Competition Provisions in the Telecommunications Act of 1996, Petition for Expedited Rulemaking by LCI International Telecom Corp. and Competitive Telecommunications Association, FCC Docket No. 96-98, dated May 30, 1997, 32-38 (discriminatory processing and support of orders by Ameritech). That AT&T may now have become the victim of its offspring is a graphic illustration of the fact that the size of the would-be entrant does not guarantee entry. Even Goliath can be deterred from entry where David possesses vertical market power.

[15] Known as operations support systems ("OSS"), these computer facilities are a key element which allow for preordering, ordering, provisioning and many other service functions, including maintenance and repair, billing, network control and forecasting. As a bottleneck facility essential to entry into the market, the OSS may be analogized to electric transmission or distribution systems. Local incumbents are required to open their markets to competition under section 251 (c) of the Telecommunications Act of 1996, 47 U.S.C. §§151 et seq. Their alleged reluctance to comply is described in Implementation of the Local Competition Provisions in the Telecommunications Act of 1996, Petition for Expedited Rulemaking by LCI International Telecom Corp. and Competitive Telecommunications Association, FCC Docket No. 96-98, dated May 30, 1997. Under an order issued by the Federal Communications Commission ("FCC"), local incumbents are now required to provide competitors with access to their OSS equal to that which they afford to themselves. First Report & Order, FCC Docket No. 96-98 (Implementation of the Local Competition Provisions of the Telecommunications Act of 1996) (noting "anecdotal evidence suggesting that incumbent LECs may not be providing nondiscriminatory access to OSS functions . . . consistent with statutory requirements").

[16] Binz & Frankena, App. B, 86.

There is also a history of vertical market power abuse in the electric industry, beginning with the classic bottleneck case, Otter Tail Power Company v. U.S. 411 U.S. 910 (1973). In Otter Tail, a vertically integrated utility's outright refusal to wheel competing power to a neighboring municipal system over the utility's transmission lines was found to constitute a monopolization offense under section 2 of the Sherman Act.

Typically, however, affiliate abuses are more subtle, and less amenable to antitrust enforcement, than an outright denial of access to the market.[17] A marathon California case provides one example. In 1990 the California Public Utilities Commission ("CPUC") disallowed $37.5 million in overpayments made by SoCal Edison ("SCE") to an unregulated "qualifying facility" affiliate during the 1980s, ruling that SCE had paid for firm capacity, while receiving only as-available capacity. The California Attorney General commented: "The fact that this proceeding took two years to get to an ALJ decision illustrates the limits of regulation in detecting and correcting abusive self-dealing practices."[18]

But the 1990 proceeding proved to be only the tip of the iceberg. In 1993, the CPUC rolled the 1990 disallowance into a global settlement with SCE amounting to $250 million, a sum characterized by the agency as "at the low end of reasonableness," resolving years of litigation stemming from charges that SCE had engaged in self-dealing in connection with the regulated utility's purchases of power from a total of thirteen unregulated affiliate qualifying facility generators.[19]

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[17] Not all denials of access are actionable under the antitrust laws. See R. Bolze & J. Ostoyich, Open Access & the Sherman Act: A Guide to the Essential Facilities Doctrine, CCH Power & Telecom Law, Sep. -Oct. 1998, 10, 15.

[18] 73 Op. Att'y Gen. Cal. 366, 1991-1 Trade Cas. ¶69,427

[19] Binz & Frankena, App. B, 86 -88.

Nor is the record purely historical. Allegations in recent cases, some proven or admitted, others pending, testify to the current persistence and intractability of vertical market power abuses. In California, an audit performed for the CPUC Office of Ratepayer Advocates reported in 1997 that Pacific Gas & Electric Company ("PG&E"), an incumbent utility with a regulated t&d monopoly, applied $33.7 million of ratepayers' money to subsidize competitive affiliates. In their 1000-page report, the auditors found a catalog of vertical abuses, including overbilling of the regulated t&d by an affiliate and underbilling and provision of free information by the t&d to other affiliates. The auditors concluded that a "significant percentage of PG&E's costs attributable to non-utility affiliates was funded by PG&E's ratepayers."[20]

In Massachusetts, Boston Edison Company is alleged to have misappropriated cost advantages and investment belonging to ratepayers in funding unregulated subsidiaries;[21] while in Connecticut, a Department of Public Utility Control audit uncovered attempts by Northeast Utilities to recover from monopoly ratepayers marketing and other expenses incurred by a competitive affiliate.[22] Meanwhile, at FERC, Washington Water Power Company was recently found to have favored its affiliate, Avista, by providing discounted transmission service unavailable to others, in violation of open access rules.[23]

A recent complaint to the New York Public Service Commission with regard to joint marketing illustrates utility confidence that trading on incumbent goodwill works to affiliates'

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[20] Overland Consulting, Audit of Affiliate Transactions of the Pacific Gas & Electric Company (Redacted), (Oct. 1997), Executive Summary at 2; see San Jose Mercury News, Dec. 4, 1997. In a recent telephone conversation with the Department, the California Office of Ratepayer Advocates indicated that hearing in this case has been completed; briefing is ongoing, and a decision is expected within a few months.

[21] DPU/DTE Order No. 97 -63, April 17, 1998 at 58; Affidavit of Gary C. Harpster, February 24, 1998.

[22] Department of Public Utility Control, Financial & Operations Review of the Connecticut Light & Power Company, Docket No. 97 -05, Dec. 31, 1997 at 30 -31.

[23] Washington Water Power Co., 83 FERC ¶61282 (1998).

advantage. In an October 9, 1997 advertisement in the Wall Street Journal and the New York Times, Con Edison proclaimed:

> With so many unfamiliar names out there, it's nice to know that one thing stays the same. Con Ed Solutions and Con Ed Development will still offer the unrivaled reliability of Con Edison itself. After 117 years of energizing New York, we bring proof, not promises, to the table. CON EDISON: THE COMPANY YOU KNOW. THE PEOPLE YOU TRUST.[24]

On June 26, 1998, PECO Energy was found to have violated applicable affiliate rules by maintaining a cyberlink between its own internet page and that of its marketing affiliate, Excelon, creating an environment which blurred the distinction between the companies, and channeled retail customers to the affiliate. PECO admitted the violation, commenting that "it was an oversight on our part."[25]

The pattern of affiliate abuse apparent in these cases reflects a simple fact: management has an obligation to shareholders to explore every lawful avenue in search of the market advantages and profits which can be gleaned from vertical integration. It must be expected that corporate management will seek creatively and conscientiously to discharge that obligation.

D. <u>Transmission-Derived Vertical Market Power</u>

Vertical market power in the electric industry may derive from integrated ownership of (a) generation and interstate transmission facilities; or (b) a retail marketing business and local transmission and distribution (t&d) facilities. In this section, we consider the former.

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24 <u>See</u> Letter, H. Fromer <u>et al</u>. to NYPSC Chair J. O'Mara dated Oct. 20, 1997.

25 <u>Pennsylvania Commission Orders PECO to Remove Links on Web to Unregulated Affiliates</u>, Electric Utility Week's Energy Services and Telecom Report, July 16, 1998; Electric Power Alert, July 15, 1998.

Maine has sought to address vertical market power derived from transmission ownership in part through legislation requiring incumbent utilities to divest most generation assets. This divestiture process is already well under way.[26] If the wholesale market were geographically limited to Maine, divestiture, which severs the vertical link between transmission and generation, would have constituted a complete and effective remedy.[27]

However, because the wholesale market of which Maine[28] forms a part stretches across the six New England states, transmission-derived vertical market power is a regional problem, subject to federal jurisdiction. At the federal level, the Federal Energy Regulatory Commission ("FERC") has prohibited discriminatory and exclusionary transmission practices through its Open Access Rules.[29] Further, FERC has strongly encouraged the formation of Independent System Operators ("ISO"). ISOs are special-purpose entities to which utilities delegate control over pricing, scheduling, operation, maintenance and expansion of a regional transmission system. With the active support of the Commission, the New England Power Pool ("NEPOOL") (the regional utilities consortium) proposed and FERC in June 1997 approved the establishment of ISO-New England, Inc. ("ISO-NE"), a regional ISO for New England.[30]

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26 All three of Maine's investor-owned utilities are in the process of divesting generation assets. As we note below, CMP's pending divestiture to FPL Group has recently become the subject of litigation.

27 The remedy would be equally effective and complete, of course, if every other state in the region mandated divestiture. However, although some divestiture has occurred (in Massachusetts, Boston Edison Company and New England Electric System have both sold substantial generation assets), no other state in the region has required it. Indeed, we are not aware of any state in the country other than Maine which has mandated divestiture through legislation. Some states have provided incentives for voluntary divestitures.

28 Excluding a tricounty section of northern Maine.

29 Orders 888 & 889 mandate that public utilities unbundle generation and transmission and provide the same types of transmission service to others as they use themselves, with comparable terms, conditions, information and prices for all.

30 New England Power Pool, 79 FERC ¶61,374 (1997). The FTC has expressed the view that states involved in the formation of ISOs should exercise vigilance to ensure that the ISO remains sufficiently independent. Comment of the Staff of the Bureau of Economics of the Federal Trade Commission, May 15, 1998, La. PSC

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The principal risk from transmission-derived vertical market power is that vertically-integrated transmission owners will discriminate against new entrants to wholesale markets and seek to raise the barriers to entry, stifling competition. FERC's reliance on open access rules and ISOs to protect against this risk has not been uniformly successful. Open access behavioral rules have not been fully effective to prevent discriminatory conduct by transmission owners.[31] Moreover, in July 1998, NEPOOL petitioned FERC for approval of a complex system for interconnecting newly constructed merchant plants to the grid which assigned steep charges for unneeded transmission upgrades to new entrants.[32]

The interconnection system reflected in the NEPOOL proposal constituted an attempted exercise of vertical market power which would have raised significant barriers to entry in New

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Docket No. U-21453, 33. The Department and the Commission will continue to encourage ISO-NE to chart a course independent of NEPOOL. For the longer term, some commentators predict that ISOs will turn out to be "a transitional device, a stop on the way to a 'TransCo' or 'Gridco,' where not only operation but ownership of transmission is divorced from generation and marketing activities." F. Norton & G. Bernstein, ISOs -- In Search of Competitive Electricity Markets, CCH Power & Telecom Law, Nov. -Dec. 1997, 18, 23. Others strongly advocate fully independent transmission networks. H. Trebing, Market Concentration and the Sustainability of Market Power In Public Utility Industries, Quarterly Bulletin Vol. 19 No. 1, 66; R. Pierce, The Advantages of Deintegrating the Electricity Industry, Electricity Journal, Nov. 1994, 16.

[31] E.g., Petition for a Rulemaking on Electric Power Industry Structure and Commercial Practices and Motion to Clarify or Reconsider Certain Open Access Commercial Practices, dated March 25, 1998, FERC Docket No. 95 -8 -000, at 2. See also Illinois Power to Recompute ATC, Wheeling & Transmission Monthly, June 1998 (FERC has directed Illinois Power to recompute available alternative transmission capacity following a complaint by Morgan Stanley that Illinois Power was discriminating in favor of its own bulk power marketing arm at Morgan Stanley's expense); and see Professor Tells FERC ATC Posting Is Bunk, Restructuring Today, Sept. 25, 1998 (quoting R. Pierce, "if I have the means to benefit myself and hurt a competitor I'm always going to do it").

[32] The NEPOOL proposal required that every generator connected to the grid have access to an unconstrained transmission path to any other point on the grid, assuming that all other generation was in operation. Because planned new entry is likely to result in a power surplus in New England, this system would have resulted in an overbuilding of transmission, raising unnecessary barriers to entry. Moreover, by assigning a disproportionate share of the cost of upgrades to new entrants, NEPOOL would have accorded preferential rights to existing transmission to incumbents.

England, and was therefore a matter of significant concern to the Department and the Commission.[33] However, FERC has recently rejected NEPOOL's proposed system, requiring it to formulate a new interconnection plan.[34] When a revised NEPOOL proposal is forthcoming, it will merit careful scrutiny to ensure fair treatment of new entrants. Accordingly, the Department and the Commission will continue to exercise vigilance in the context of ongoing proceedings at FERC, while working with ISO-NE and NEPOOL to achieve consensus wherever possible.

E. Distribution-Derived Vertical Market Power

In contrast to interstate transmission facilities and the regional wholesale market, the relationship of local t&d companies to their retail marketing affiliates is squarely within Maine's legislative jurisdiction. In its restructuring statute, Maine has enacted a package of remedies designed to address this aspect of the problem of vertical market power. The statute adopts a two-pronged strategy, comprising first, a code of conduct designed to police the relationship between t&ds and marketing affiliates, and second, an innovative provision setting an upper limit on the market share which may be attained by the affiliate in the t&d service territory.

1. Statutory code of conduct. The statutory code,[35] as developed in the Commission's proposed rule,[36] governs and restricts the conduct of t&d companies and their affiliated retail marketers in the following areas.

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[33] See Comments of the Maine Attorney General On the NEPOOL Report of Compliance, August 10, 1998, FERC Docket No. ER98-3853-000; Comments of the Maine Public Utilities Commission, ISO-NE's Assessment of the Competition & Efficiency of the NEPOOL Markets, October 13, 1998, in FERC Docket Nos. OA97-237-000, ER97-1079-000, ER97-3574-000, OA97-608-000, ER97-4421-000 & ER98-499-000..

[34] New England Power Pool, FERC Docket No. ER98-3853-000, Draft Order Conditionally Accepting Compliance Filing, As Modified, And Accepting, In Part, And Rejecting, In Part, Proposed Tariff Changes, As Modified. This decision and a companion decision has led FPL Group to file litigation in which FPL seeks to escape from its contract to purchase CMP generation assets.

[35] 35-A M.R.S.A. §3205(3).

[36] The rule is authorized under 35-A M.R.S.A. §§3205(4) (large utilities, viz., CMP and BHE) and 3206 (2) (small utilities, viz., MPS), and applies the same provisions to both categories.

- **Favoritism**. A t&d may not accord to its affiliate preferential access to regulated products or services, or information.

- **Tying.** A t&d may not condition the provision of a regulated product or service on the purchase of products or services furnished by an affiliate**.**

- **Information restrictions.** A t&d may not share with any retail marketer (including its affiliate) market information acquired from other marketers or developed by the t&d in the course of providing service; or proprietary customer information without the authorization of the customer.

- **Representations.** A t&d may not: give the appearance of speaking on behalf of an affiliate; represent that any advantage in terms of t&d service accrues to customers of the affiliate; engage in joint marketing with the affiliate or permit affiliate use of the t&d name and logo; provide any opinion concerning the relative merits of competing retail marketers.

- **Separation.** T&d employees may not be shared with and must be physically separated from those of an affiliate (separate buildings, telecommunications and computer systems); records and books of account must be separately maintained.

- **Penalties.** The code provides for two levels of sanctions for violations. Any violation may be punished with an administrative penalty in the amount of $10,000 per day; knowing violations which result or have the potential to result in substantial injury to consumers or competition may be penalized with an order requiring the t&d to divest its retail affiliate.

Numerous states have adopted or are considering codes of conduct. Measured against provisions in place in other jurisdictions, the code reflected in Maine's statute and proposed rule represents a comprehensive effort to address the problem of vertical market power.[37] Nevertheless, as we discuss below, there are limited areas in which the statutory code should be tightened and improved.

2. Statutory market share limitation. The second prong of the statutory strategy for dealing with vertical market power is the market share limitation.[38] This provision

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[37] Among states which have adopted or are considering codes of conduct governing retail marketing of electricity by t&d affiliates are California, Illinois, Massachusetts, Oregon and Texas. A number of other states have in place rules governing affiliate marketing of gas (Delaware, Georgia, Indiana, Kansas, Maryland, Missouri, New Jersey, New Mexico, New York, Ohio, Rhode Island, Pennsylvania and Wisconsin).

[38] 35-A M.R.S.A. §3205 (2) (B).

limits the retail affiliate of a t&d to an overall 33% market share within the service territory of the t&d. In addition, a limit of 20% is imposed on the share of standard offer (default service) business which may be awarded to the affiliate in the t&d service territory. The market share limitation applies to Central Maine Power ("CMP") and Bangor Hydro-Electric Company ("BHE"), but does not apply to Maine Public Service Company ("MPS"), the sole "small utility" within the statute.

The purpose of the market share limitation is twofold: to prevent a t&d affiliate from actually amassing a dominant market share within its service territory, and to ensure that its perceived ability to exert dominance does not chill potential new entry. No other state has enacted or adopted a market share limitation.[39]

3. Legislative compromise. Maine's two-pronged statutory approach was developed as a compromise between contending opposites. Utilities strongly disagreed with the market share limitation, and took issue with aspects of the code of conduct as well. In particular, the joint marketing ban, interpreted in the proposed Commission rule as a bar on use of the same name and logo by the t&d and its marketing affiliate, has been controversial.

On the other hand, the Commission and the Department continue to subscribe to the view that a structural solution, i.e., enactment of a complete or partial ban on retail marketing by affiliates in the t&d territory, would have been preferable to the regulatory approach selected by the Legislature.[40] Nevertheless, we recognize that experience may be the best guide to whether the rules established by the statute should be relaxed or reinforced. We therefore recommend only

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[39] However, the California Public Utilities Commission ("CPUC") has considered and rejected a similar measure. Opinion Adopting Standards of Conduct Governing Relationships Between Utilities and Their Affiliates, CPUC Decision 97 -12 -088, Dec. 16, 1998, Conlon, Comm'r, dissenting, 4 (hereinafter "Conlon, dissenting"). Conlon proposed a market share limitation fixed at 20% of each market segment (industrial, commercial, residential). It would have remained in effect for two years.

[40] A partial ban would apply to the competitive retail market, but not the standard offer bid process.

relatively minor (though in our view important) proposed enhancements to the statutory code and market share limitation provisions.

In the paragraphs following, we review (a) the importance of retaining the ban on shared name and logo use; (b) recommended code enhancements; (c) the value of the market share limitation, and recommended modifications; and (d) the merits of a prophylactic ban as a residual option.

4. The name & logo issue. Maine's statutory code bars joint advertising or marketing by the incumbent utility and its marketing affiliate.[41] In its proposed rule, the Commission has interpreted this prohibition to include use of the same or a substantially similar name or logo.[42] Discussing the proposed rule in a recent decision, the Commission held that the name "MainePower" is not substantially similar to "Central Maine Power," and authorized its use. The Commission noted that while the rule bans joint advertising or marketing, CMP and MainePower may nevertheless disclose their affiliation in response to inquiry, or in nonmarketing contexts such as shareholder communications or regulatory filings.[43]

Other states have addressed the joint marketing issue in various ways. California, for example, rejected a prohibition on shared name and logo use, requiring instead an accompanying affirmative disclosure that the affiliate is a separate, nonregulated entity, and that the customer does not have to purchase the affiliate's product in order to continue to receive regulated service from the t&d.[44] However, a recent scholarly analysis concludes that a ban on joint use of an

[41] 35-A M.R.S.A. §3205 (3) (J).

[42] Rule ¶3 (J) (2).

[43] Order dated July 6, 1998, Maine PUC Docket No. 97 -930.

[44] California Affiliate Transaction Rules, ¶V.F. Texas and Massachusetts are considering similar rules. Such provisions may not always have the desired effect. Shortly before the inauguration of retail competition in California, PG&E ran a nationwide ad campaign in which the required disclaimer was virtually illegible due

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incumbent brand is warranted, at least during the initial development phase of a newly deregulated market.[45]

There are compelling reasons for retaining the prohibition on shared name and logo use without modification. As long as the utility and its marketing affiliate share the same name and logo, it will be difficult to dissociate the two entities in the marketplace or for purposes of regulation. As a result, to permit shared name and logo use would represent an open invitation to the incumbent utility (a) to engage in cross-subsidization (promoting its name at ratepayer expense for the benefit of the unregulated affiliate);[46] (b) to capitalize on the familiarity of its name to seize a high market share in the initial phase of market development, discouraging entry by others;[47] and (c) to deceive consumers by suggesting that affiliation with the t&d results in greater quality or reliability of service.[48]

5. Code enhancements. Maine's code is reasonably comprehensive, but should be improved and tightened by means of legislation in limited areas.

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to small font size, dark background and its placement on the vertical margin. The CPUC immediately determined that a violation had occurred; it has since levied a $1.68 million penalty. CPUC Fines PG&E For Misuse Of Name And Logo In Promotions By Electricity Affiliate, November 5, 1998, http://www.cpuc.ca.gov/news/981105_PG&E_Fined.htm.

45 J. Abel & M. Clements, Should Utility Incumbents Be Able To Extend Their Brand Name to Competitive Retail Markets? An Economic Perspective, Electricity Journal, June 1998, 49, 56 (hereinafter "Abel & Clements") ("allowing unrestricted brand name extension from an incumbent utility to an affiliate in the emerging competitive retail market could seriously cripple viable market entry and, therefore, the early phases of retail competition").

46 See Comment of the Staff of the Bureau of Economics of the Federal Trade Commission, June 19, 1998 Before the Public Utilities Commission of Texas, Project No. 17549, 4 -5 ("FTC Texas Comment") ("a regulated parent utility may have an incentive to overinvest in reputation building" if it is able to include investments in its reputation in its rate base while realizing gains in the unregulated market; "[h]arm to both competition and consumers may occur from overinvestment and cross-subsidization").

47 Abel & Clements 56; Conlon, dissenting, 3.

48 Binz & Frankena 71; FTC Texas Comment 5 (if substantial minority of consumers takes a particular message from advertisement, and that message is likely to mislead consumers to their detriment, advertisement is deceptive under Federal Trade Commission Act §5; affiliate use of incumbent name and logo may violate this standard, if it implies to consumers "that the relationship between the utility and the affiliate is different from what it really is").

- **Cross-subsidization**. No provision of the current statutory code directly addresses the problem of cross-subsidization. Cross-subsidization is addressed in the proposed rule by means of a provision to the effect that "[a] distribution utility and its affiliated competitive provider must comply with all applicable provisions of Chapter 820", a reference to the Commission's so-called Cochrane rule, which is authorized by 35-A M.R.S.A §§ 713 -715. Nevertheless, because it is an expression of vertical market power which could damage competition, cross-subsidization should be explicitly prohibited and penalized in the statutory code of conduct.[49]

- **Log.** The code currently requires the t&d to maintain a log of all requests for information made by the marketing affiliate and its competitors.[50] As an aid to detection and enforcement, the Commission should be empowered to extend this requirement to other categories of transactions by rule.

- **Penalties.** The statutory code provides for two types of sanctions, as noted above. The divestiture remedy for knowing violations substantially injurious to consumers or competition is a draconian measure valuable as a deterrent, but likely to be employed only as a last resort. The only other option available is a financial penalty of up to $10,000 per day for any code violation.[51] However, it is possible to conceive of one-time violations, for example an advertising violation or an exchange of information, serious enough to render a $10,000 penalty entirely inadequate.[52] In order to give the rule additional force as a deterrent, and to afford the Commission more flexibility in crafting appropriate remedies, provision should be made for an intermediate penalty, e.g., suspension of the right to engage in retail marketing for up to three years, and a much more substantial maximum financial penalty for certain one-time offenses (up to $100,000). In addition, disgorgement of profits or benefits should be available as a sanction. Finally, the statute should be amended to make clear that the penalty provisions of the code of conduct are applicable to small t&ds (i.e. MPS) as well as large ones.

6. Market share limitation issue. Foreclosing shared name and logo use reduces, but does not eliminate, the risk of market dominance. We anticipate that by March 1,

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[49] It is far from clear that a violation of the Cochrane rule would be subject to the sanctions provided in the code of conduct section of the restructuring statute, including divestiture, unless that section is amended.

[50] 35-A M.R.S.A. §3205 (3) (H).

[51] 35-A M.R.S.A. §3205 (5).

[52] The CPUC recently fined PG&E $1.68 million for an advertising violation. See fn. 35 above.

2000, the implementation date for retail choice, many consumers in the CMP service territory will know that MainePower is a CMP affiliate.[53]

In markets where an incumbent utility has long held a monopoly, incumbent goodwill and customer inertia can exert a powerful drag on competition. For example, in 1984, the year of its breakup, AT&T was able to retain a 90% share of the long-distance market. It took a dozen years before that share dropped below 50%.[54] Absent a market share limitation, it could well "take years [for incumbent market shares] to decline to where there would be general agreement that market dominance was not a problem."[55]

The market share limitation serves an important purpose -- that of permitting "entry of enough additional marketers to ensure a competitive market."[56] Its removal would therefore be ill-advised, unless affiliate marketing in the t&d territory is banned altogether. Rather, it represents an essential element of the balance struck by the Legislature in Maine's restructuring statute. However, we recommend that the Commission's ability to penalize violations of the market share limitation be enhanced and clarified.

The statutory penalty provisions may be inadequate to remedy violations of the market share limitation. As written, it is not clear whether the penalty provision, 35-A M.R.S.A. §

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[53] In recent press releases, CMP draws attention to its affiliation with MainePower. E/PRO Wins Contract for Edwards Dam Removal, Sept. 15, 1998 (MainePower listed as a subsidiary in article unrelated to its activities); Clarifying CTP Stock Listing, CMP Group, Sept. 3, 1998 (MainePower listed as subsidiary in article relating to listing of parent company stock). Further, a visit to CMP's webpage readily yields information concerning "MainePower, a unit preparing to operate as a competitive electricity marketer." www.cmpco.com.

[54] It is sobering to note that in California's retail electric market, only 33,000 of 10 million retail customers initially chose an alternative provider, despite an $89 million consumer education campaign.

[55] K. Costello & K. Rose, Some Fundamental Questions on Market Power: No Easy Answers for State Utility Regulators, Electricity Journal, July 1998, 73. See also W. Shepherd, Monopoly and Antitrust Policies In Network-Based Markets Such as Electricity, 14 (Paper delivered at Symposium on Virtual Utility, Rensselaer Polytechnic Institute, March 31, 1996) (dominance and tight oligopoly usually fade slowly, if at all).

[56] Conlon, dissenting 4.

3205 (5), would cap penalties for market share limitation violations at $10,000 -- surely an inadequate sanction. The statute should be amended to provide for greater flexibility, and a much more significant maximum penalty. Disgorgement of profits for minor infractions, and surrender of revenues for more serious breaches, should be provided as options.[57]

7. Ban on marketing by affiliates. In the restructuring statute, the Legislature has chosen a regulatory or behavioral approach to address the problem of vertical market power, combining a code of conduct and a market share limitation. In making this policy choice, the Legislature rejected an alternative, structural remedy, namely, enactment of a complete ban on marketing by t&d affiliates.[58] Maine's selection of a regulatory rather than a structural remedy is consistent with restructuring policies adopted across the country. While numerous states have enacted or promulgated codes of conduct, to our knowledge no state has imposed a ban on marketing by affiliates. Two states, California and New Hampshire, have explicitly considered and rejected such a ban.[59]

We are not here advocating that the untested compromise approach reflected in the statute be abrogated. Even if it is not ideal from our perspective, it may prove a workable solution.

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[57] Note that the statute requires the Commission to reevaluate the need for the market share limitation, and report on its findings to the Legislature, no later than January 1, 2005. 35-A M.R.S.A. § 32121 (2).

[58] The Commission recommended a ban on affiliate marketing in its Restructuring Plan. See Final Restructuring Plan, December 1, 1996, 32. This recommendation was discussed further in a letter from the Commission to the Chairs of the Joint Standing Committee on Utilities & Energy dated April 28, 1997.

[59] In California, The Utility Reform Network (TURN) moved for a two-year ban on affiliate marketing. In denying the motion in favor of a code of conduct approach, the CPUC explained its view that dominance by an affiliate marketer was less likely because California's implementation of retail choice did not involve a phase-in. Opinion Adopting Standards of Conduct Governing Relationships Between Utilities and Their Affiliates, CPUC Decision No. 97 -12 -088, Dec. 16, 1998, 15 -17. In New Hampshire, the Public Utilities Commission initially approved a restructuring plan which included a ban on affiliate marketing in the t&d service territory. In Re Restructuring New Hampshire's Electric Utility Industry, 175 PUR4th 193, 222 (1997). Subsequently, the PUC vacated this prohibition, deferring a final determination on the issue until a later time. Electric Utility Restructuring, Order On Requests for Rehearing, Reconsideration and Clarification, Order No. 22,875 (NH PUC, Mar. 20, 1998), 23. For a discussion of this issue, see K. Jaffe, Emerging State Rules For Retail Marketing By Electric Utilities After Restructuring, CCH Power & Telecom Law, May-June 1998, 34, 35 -36.

However, a ban on affiliate marketing in the t&d service territory remains an important residual option, should experience show that permitting any marketing by t&d affiliates is inimical to the public interest. Accordingly, we review the merits of a ban below.

Enactment of a ban would not be unprecedented. To cite one important analogy, local Bell telephone monopolies are barred by law from providing long distance service within their regions until they show that they have opened their local networks to competition.[60] Moreover, there is a compelling logic to the structural approach: a ban would constitute a totally effective solution which would eliminate, once and for all, the problem of vertical market power. It would appear that even if it proves workable, the regulatory solution selected in Maine necessarily falls short, measured against this standard.

It is a consistent theme of both the U.S. Department of Justice ("DOJ") and the Federal Trade Commission ("FTC") (in contrast to the states) that structural remedies for market power are invariably more effective than behavioral monitoring and enforcement. The reasons for this conviction are well stated by William Baer, FTC Bureau of Competition Director, in a recent speech:

> A behavioral approach ... has several drawbacks. First, it does not eliminate the incentive and opportunity to engage in exclusionary behavior. Rules can try to limit the opportunity, but few rules are invulnerable to evasion. Second, detection of violations can be very difficult. For example, discrimination in access could take the form of a subtle reduction in the quality of service, whose effects

[60] 47 U.S.C. §271 (a) & (b). Significantly, these provisions were recently upheld over a constitutional challenge. SBC Communications, Inc. v. FCC, No. 98 -10140, September 4, 1998 (5th Cir.); may be found at http://www.ca5.uscourts.gov/opinions/pub/98/98-10140-CV0.HTM. See also Commonwealth Edison Company v. Illinois Commerce Commission, 692 N.E.2d 1350 (Ill. App. 1998) (upholding regulatory agency's denial of utility petition for approval to provide energy support services to energy users).

> could be difficult to identify and measure. Third, behavioral rules can require long-term monitoring of compliance, which can be a costly process .... Fourth, it may be difficult to know whether we have selected the right rules.[61]

There are two other important reasons for rejecting the regulatory, behavioral approach to vertical market power. The first is that restructuring should be conceived as far as possible as a process of deregulation: opening markets to unfettered competition, for the benefit of consumers. Reregulation designed to accommodate the participation of t&d affiliates in retail markets is inconsistent with the fundamental goals of restructuring, and appears calculated to benefit t&d shareholders rather than consumers. A second reason is that, just as there is a need for a regional ISO to be an independent grid administrator, so it is essential that the t&d responsible for local distribution of electricity be neutral and independent. Permitting a t&d affiliate to engage in retail marketing runs the risk of compromising its neutrality.

Experience underscores the limitations of the regulatory approach.[62] In the course of the AT&T divestiture litigation, officials of the Federal Communications Commission ("FCC") testified to the ineffectiveness of regulation in preventing vertical market power abuses. In advocating divestiture rather than a court-ordered code of conduct, DOJ made clear its view that "[n]either of these problems [favoritism and cross-subsidization] has thus far proven amenable to

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[61] W. Baer, FTC Perspectives on Competition Policy & Enforcement Initiatives in Electric Power, Washington D.C. Dec. 4, 1997.; see J. Klein, Making the Transition From Regulation To Competition: Thinking About Merger Policy During the Process of Electric Power Restructuring, Washington DC, Jan. 21, 1998 ("the regulatory agency often ends up playing catch-up, while the market forces move forward and the underlying competitive problems escape real detection and remediation").

[62] Most of the examples of vertical market power in action cited above occurred in spite of regulatory code of conduct provisions.

successful regulatory solution .... [T]he anticompetitive problems inherent in the joint provision of regulated monopoly and competitive services are ... insoluble."[63] In approving the proposed settlement, the court agreed:

> AT&T's pattern during the last thirty years has been to shift from one anticompetitive action to another, as various alternatives were foreclosed through the action of regulators or the courts or as a result of technological development. In view of this background, it is unlikely that, realistically, any injunction [i.e. code of conduct] could be crafted that would be both sufficiently detailed to ban specific anticompetitive conduct yet sufficiently broad to prevent the various conceivable kinds of anti-competitive conduct that AT&T might employ in the future.

Thus, the court preferred the "surer, cleaner remedy" of divestiture adopted in the proposed settlement.[64]

A ban on affiliate marketing represents a readily attainable and fully effective solution to the problem of vertical market power.[65] Experience of the regulatory approach in other jurisdictions suggests that, by contrast (1) it does not prevent the exercise of vertical market power; (2) detection, prosecution and proof of violations can be difficult, uncertain, costly and time-consuming; and (3) successful abuses can net very substantial gains to the utility at consumer expense. In addition, it requires little insight to predict that for every meritorious allegation of a regulatory violation, there will be numerous groundless complaints which must nevertheless be investigated and in some cases litigated.[66] Ultimately, the high cost of regulation and its apparent

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[63] DOJ, Response to Public Comments on the Proposed Modification of Final Judgment, 47 Fed. Reg. 23, 320 -336 (1982).

[64] U.S. v. AT&T, 552 F.Supp. 131, 167, 168 fn. 155 (D.DC 1982).

[65] There are less draconian options which could be considered. A partial ban on affiliate marketing, in the competitive segment of the market only, would leave the affiliate free to compete for standard offer business.

[66] For example, in the event of another ice storm, it is easy to imagine an avalanche of complaints with regard to any t&d affiliate customer who happened to be reconnected before any customer of another competitive provider.

inability to solve the problem of market power could jeopardize the success of the fundamental goals of restructuring: open and robust competition, and lower prices.

Accordingly, if the legislative compromise reflected in the statute proves unworkable, the Commission and the Department respectfully counsel that a ban on affiliate marketing in the t&d territory should be reconsidered.[67]

F. Costs of Regulation

Precision in estimating the costs of regulating affiliate marketing is elusive. However, the costs of regulation may be high.

The purpose of regulation is to protect the retail market from the damage to competition which could be wrought by the exercise of vertical market power. The need for regulation arises from the participation of the t&d affiliate in the retail market. The motive for such participation, of course, is profit. Regulation, then, is a necessary condition of the t&d affiliate's license to profit from energy sales in the retail market. It can be argued, on this basis, that all the costs of such regulation should be borne by affiliate marketers and their stockholders.

Under the present legislative scheme, however, it appears that the costs of the regulatory effort required to police the vertical boundary between the t&d and its affiliate will be borne entirely by ratepayers.[68] At a minimum, we recommend legislation to adjust this burden by

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[67] Note that it can be plausibly argued (although we are not necessarily persuaded) that allowing the participation of t&d marketing affiliates benefits consumers by increasing consumer choice. It can also be argued (and we are persuaded) that t&d affiliates should be given the opportunity to demonstrate that they can play by the rules.

[68] The restructuring statute requires the Commission to report to the Legislature annually regarding its "actual and estimated future costs of enforcing and implementing the provision of this chapter governing the relationship between a [t&d] utility and an affiliated competitive electricity provider and the costs incurred by [t&d] utilities in complying with those provisions." 35-A M.R.S.A. §3217 (1). At the outset, however, the Commission's costs appear to be chargeable to its general budget funded by utility assessments, and ultimately to ratepayers.

imposing the cost of meritorious enforcement proceedings under the code of conduct or market share limitation on shareholders rather than ratepayers.

G. Recommendations

1. There is a need for an enhanced statutory penalty provision for exceeding market share limitations.

2. The statutory code of conduct should be tightened as follows:

(a) Cross-subsidization should be explicitly prohibited.

(b) The Commission should be empowered to expand the requirement that a log of information requests be maintained to include other categories of transactions.

(c) More flexible provision for penalties should be made in order to enhance deterrence and enforcement. This should include provision for intermediate penalties for code infractions, e.g., a three-year maximum license suspension, and a $100,000 maximum for certain one-time violations; and provision for disgorgement of profits.

3. It should be provided that all costs of enforcement which result from violations of the code of conduct and the market share limitation may be assessed against the t&d and its affiliate.

IV. HORIZONTAL MARKET POWER: NEW ENGLAND

A. Summary

Horizontal market power is the ability of a single dominant firm or group of firms to profit by raising prices above competitive levels. An indicator of the extent to which a market is subject to horizontal market power is the size of individual market shares, and the overall level of market concentration.

Southern and central Maine form part of a regional New England wholesale electricity market, whose geographic boundaries are coextensive with the NEPOOL grid. Occasionally, smaller geographic markets, known as load pockets, may arise within the grid as a result of transmission constraints or outages. Northern Maine, a separate market, is analysed in a subsequent section of this report.

We use the Herfindahl-Hirschman Index (HHI) to estimate the level of concentration in New England electricity markets. The HHI is an indicator rather than an absolute measure of horizontal market power. Accordingly, we also review additional factors in our assessment. Specifically, we look at the responsiveness of the New England market to competitive forces, and the effect of new entry. The related tasks of estimating levels of concentration and analysing market power are complicated by the rapid pace of change in the New England electric industry in recent years.

The HHI for New England's wholesale energy market for summer 2000, allowing for new entry and out-of-region imports, shows a moderate level of concentration by federal standards, indicating a corresponding degree of market power. With two participants holding 50% of the market, and four over 60%, the market is subject to oligopoly control.

Computer simulations suggest that oligopoly control may pose a special danger in the context of New England's electricity spot market, which will function as the principal price-setting mechanism in the region. The market may be vulnerable to unilateral strategic behavior, or gaming, as well as collusive practices. Simulation results show that if market leaders engage in such manipulative behavior, wholesale clearing prices could rise by as much as an average of 10%.

Over the next decade, planned new entry is likely to increase competition in the New England market. In the short to medium term, market power is likely to remain problematic. However, New England's interstate wholesale markets are subject to federal jurisdiction. Maine's ability to address horizontal market power in this context through legislation is limited to the margin. We recommend a limited legislative measure focused on market power within a load pocket, i.e., an area within Maine temporarily isolated from the grid (and federal jurisdiction) by a transmission outage. Beyond this, the Commission and the Department have been, and will continue to be, active in representing the State's interest in promoting competitive regional markets before FERC.

B. Introduction

Horizontal market power is the ability of a single dominant firm or group of dominant firms to profit by raising prices above competitive levels. As single firm market shares increase, and the number of competing firms declines, markets become more vulnerable to market power. As an initial matter, therefore, the extent to which a market is subject to horizontal market power can be gauged by reference to the market shares of individual firms, as well as overall market concentration.

An assessment of market concentration in wholesale electricity must begin by defining the market in terms of products and geography.

C. Product Markets

The most important product for analysis in this report is electric energy. The most straightforward measure of market share for this product is capacity, which is currently traded separately. In addition to energy and capacity, competitive wholesale markets in New England will also trade in ancillary services.[69] Further, there may be circumstances in which it is useful to consider energy generated in a particular period, e.g., peaking energy, as a distinct product.[70] Similarly, energy required at a particular time, in a particular quantity, such as Maine's standard offer service, which will go out to bid pursuant to the restructuring statute in the summer of 1999, may merit consideration as a separate product market.

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[69] Ancillary services include Ten-Minute Spinning Reserve ("TMSR"); Ten-Minute Nonspinning Reserve ("TMNS"); Thirty-Minute Operating Reserve ("TMOR"); Operable Capability; and Automatic Generation Control ("AGC"), also known as load following.

[70] This is because electricity demand cannot easily be shifted from one period to another; nor can electricity be stored easily in large quantities.

Usually, however, because of the interplay among these markets, energy is likely to serve as a good proxy for other electricity products in the context of a competitive assessment.[71] In this section, accordingly, the primary focus is the electric energy product market. At the same time, we attempt to assess whether market power problems peculiar to any related product market may give special grounds for concern.[72]

D. Geographic Markets

In the electric power industry, the geographic market depends on the configuration of the grid. The extent to which power can be transmitted from point to point free of constraints or bottlenecks, which could interfere with open competition, defines the boundaries of the market. In most hours, under normal operating conditions, transmission is relatively unconstrained throughout the NEPOOL grid, which covers all of the six New England states except northern Maine (a tricounty area comprising Aroostook and parts of Penobscot and Washington Counties). Accordingly, it seems fair to accept, as a working hypothesis, that in most hours, southern and central Maine (i.e., all sections except the tricounty area) form a part of a regional New England wholesale electricity market.[73]

However, in a small number of hours, southern and central Maine may experience a peak load which exceeds the capacity of transmission ties to import competing supplies from

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[71] Joint Application Under Section 203 of the Federal Power Act For the Sale and Purchase of Generation Facilities and Related Properties, On Behalf of CMP et al., FPL et al.; Testimony and Workpapers of Joe D. Pace ("Pace") 13 -14 (natural interplay between energy and reserve and load following markets; and between capacity and operable capability markets).

[72] Maine's restructuring statute requires that, as a condition of licensing, competitive electricity providers demonstrate that no less than 30% of their portfolio of supply sources for retail electricity sales in the State are accounted for by renewable resources as defined in the statute. This requirement results in the creation of a separate product market, which is the subject of a subsequent section of this report. 35-A M.R.S.A. § 3210.

[73] New England Power Pool, FERC Docket Nos. OA97-237-000, ER97-1079-000, NEPOOL Market Power Analysis, Feb. 28, 1997, Prepared Direct Testimony of William H. Hieronymus ("Hieronymus") 19 (principal relevant geographic market is NEPOOL region); New England Power Co., FERC Docket Nos. ER-98-6-000, EC-98-1-000, Market Power Analysis: Affidavit & Workpapers of Dr. Joe D. Pace, e.g. at ¶ 34 (to same effect).

out-of-state. Under these circumstances, southern and central Maine would become a "load pocket." Within the load pocket, some generation facilities would be required to run in some hours in order to meet demand.[74] The owners of these "must-run" facilities would possess market power in affected peak hours. In addition, temporary load pockets may arise from time to time in unusual conditions[75] in more narrowly defined sections of the State. Finally, load pockets may also arise in some circumstances as a result of strategic or manipulative actions by market participants.[76]

E. Concentration Analysis

1. Herfindahl-Hirschman Index. Federal and state antitrust agencies (including the Department) employ the Herfindahl-Hirschman Index (HHI) to measure market concentration.[77] The HHI is arrived at by adding the squared market shares of all the competitors in a given market. This simple mathematical device expresses the insight that market power increases exponentially in proportion to market share. Federal antitrust guidelines used by the Department in merger enforcement indicate that a market with an HHI of 1000 or less should be viewed as unconcentrated (and therefore likely to function competitively).[78] A market with an

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74 Hieronymus 23 (Maine experiences transmission constraints in less than 0.5% of hours); CMP Request for Approval of Sale of Generation Assets, February 20, 1998, Maine PUC Docket No. 98-058, Prefiled Testimony and Exhibits of David M. Conroy, 5-6 (must-run generation may operate for periods of limited duration if outage occurs).

75 E.g., transmission outages caused by meteorological events, such as ice storms.

76 Hieronymus 25 (entity with considerable share of generation within a potentially constrainable interface could increase bid substantially, causing ISO to dispatch enough out-of-area generation to exhaust transmission capacity). We have not determined whether such manipulative actions could be brought to bear in any section of Maine.

77 Horizontal Merger Guidelines, 57 Fed. Reg. 41552 (1992) ("Guidelines") ¶1.5.

78 Id. ¶1.51 (a). For example, ten firms with market shares of 10% each would yield an HHI of 1000 (10 squared x 10).

HHI between 1000 and 1800 is described as moderately concentrated; while any HHI over 1800 is termed highly concentrated.[79] Federal authorities consider that a merger increasing the HHI by more than 100 points to a total in the 1000 to 1800 range "potentially raise[s] significant competitive concerns."[80] It is presumed that a merger which elevates the HHI by 100 or more points to a postacquisition total exceeding 1800 is "likely to create or enhance market power or facilitate its exercise."[81] A market in the moderately to highly concentrated range may therefore be viewed as likely to be subject to an increasingly significant degree of market power.

The theoretical basis for using an HHI calculation to judge the level of competition likely to be found in a market is long experience indicating that a high level of concentration tends to facilitate collusive and other anticompetitive behavior. Oligopolies (such as price cartels) are most effective when there are few members. When there are many sellers, and no dominant ones, vigorous price competition is more likely to emerge. The HHI analysis is an attempt to measure and predict the level of concentration at which oligopolistic behavior contrary to consumer interest is likely to occur.

2. NEPOOL grid. The NEPOOL grid represents a distinct electrical control area, i.e., an integrated electrical system with centralized dispatch. It is interconnected to the west with the New York Power Pool ("NYPP"), to the northwest with the Hydro Quebec system ("HQ"), and to the northeast with New Brunswick Power Corporation ("NBP"). Like other control areas in North America, the NEPOOL grid initially developed as a patchwork of isolated, vertically integrated utility systems, each generating and distributing to customers in a discrete

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79 A market comprising five firms with market shares of 20% each would result in an HHI of 2000 (20 squared x 5).

80 For example, an acquisition of a competitor with a 2% market share by a rival with a 25% share would increase the HHI by 100 points. Any merger where (acquired share) x (acquirer share) x 2 = 100 would have the same effect.

81 Guidelines ¶1.51 (c)

service territory. The grid took shape as regional connections were forged to enhance reliability and economy of service. The NEPOOL consortium, formed in 1971 in response to a massive electrical blackout affecting the entire northeast, was conceived as a means of more effectively assuring reliability and economy through coordinated operation. The consortium is made up of a large number of disparate public and investor owned utilities, and other generators.

3. A moving target. Over the past two years, NEPOOL has undergone a period of rapid evolution in preparation for the inauguration of competitive wholesale and, eventually, retail markets. As a means of addressing vertical market power concerns, FERC has authorized the transfer of control of NEPOOL transmission facilities to an independent system operator, ISO New England, Inc. ("ISO-NE").[82] ISO-NE now handles dispatch, and administers NEPOOL's open access transmission system. Once FERC authorization is received, it will also operate competitive auction markets. When implementation of these markets is authorized, dispatch will shift from a cost-based to a bid-based system.[83]

Moreover, several important investor owned utilities in the region have taken steps to divest generation facilities. In particular, New England Electric System ("NEES"), a large Massachusetts-based utility, has completed the sale of all of its nonnuclear generation assets to USGen New England, Inc. ("USGen"), a subsidiary of PG&E; while Boston Edison Co. ("BECO") has divested substantial assets to Sithe Energies, Inc. ("Sithe"). Central Maine Power's ("CMP") proposed sale of generation to FPL Group ("FPL") and Bangor Hydro-Electric's ("BHE") proposed divestiture to PP&L are currently pending. Most recently, the giant Connecticut-based Northeast Utilities ("NU") has announced its intent to divest generation assets.

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82 New England Power Pool, 79 FERC ¶ 61,374 (1997).

83 NEPOOL and ISO-NE have petitioned FERC for market implementation as of December 1, 1998.

In some cases, these divestitures, to the extent they are approved and consummated, may significantly affect concentration and competition in New England electricity markets.

At the same time, technological advances which have reduced the size and cost of gas-fired generation, together with the expected arrival of natural gas through a pipeline from Nova Scotia, have prompted an unprecedented level of interest in the construction of new generation capacity, in many cases by new entrants to the market. To the extent that it is realized, such new entry would also have significant positive implications for concentration and competition in New England.

Yet another factor which can have a significant influence on levels of concentration is the extent to which utilities retain obligations to serve "native load" pursuant to regulatory requirements[84], as a result of contractual buybacks following divestiture,[85] or as default provider after the inauguration of retail choice.[86] If a utility's capacity is committed to serving native load, it is obviously unavailable to other customers in competitive markets. In Maine, native load obligations will cease to exist concurrently with the inauguration of retail choice on March 1, 2000. It is reasonable to assume that in due time, native load obligations will disappear throughout the region. However, they will disappear on different, and in many cases, unknown schedules in different jurisdictions. This complicates the task of assessing regional concentration levels at particular points in time.

These issues are described in greater detail below. We allude to them here for the purpose of pointing out that in light of the rapid evolution of the New England market, the task of

[84] Most U.S. jurisdictions still require utilities to provide retail services in a specific franchise territory. As restructuring moves ahead, these native load obligations will disappear.

[85] For example, USGen has entered open-ended buyback contracts with NEES.

[86] In some jurisdictions, the utility remains the default provider after the inauguration of retail choice.

assessing levels of concentration and their competitive implications becomes a highly contingent and problematic exercise.

4. New England HHI. In focusing the HHI lens on the New England market, we have reviewed studies prepared by Bruce Biewald and Timothy Woolf of Synapse Energy Economics, Inc., as well as the workpapers of experts retained over the past two years variously by NEPOOL, USGen, CMP and FPL. Figure 1 below, which depicts an HHI for the New England market for summer 2000, is based on Synapse's work, with limited adjustments.[87] This analysis reflects the following assumptions:

- all proposed NEES, CMP and BECO divestitures are consummated and approved
- no NU divestitures are consummated or approved
- no utility retains an obligation to serve native load
- 50% of announced new entry scheduled for service by summer 2000 actually occurs[88]
- 1800 mw of HQ imports are allocated to parties currently receiving them under contract [89]
- moderate NYPP imports (500 mw) are included
- NBP imports are capped at tie capacity (700 mw).

To the extent that the above assumptions turn out to be invalid, major adjustments in the estimated HHI may prove warranted. For example, if NU were to move forward with significant piecemeal divestitures of its generation assets, the HHI could decline markedly. Conversely, the HHI would increase somewhat if less than the assumed amount of new entry actually occurred.

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87 Synapse examines several scenarios with regard to new entry; we employ a relatively conservative assumption in this regard (including 50% of new entry scheduled to be in service by summer 2000). In addition, we include NYPP imports at 500 mw and NBP imports at 700 mw.

88 It is unlikely that sufficient gas will be available to support more than 50% of announced new entry.

89 As of 2001, as a result of contract expirations, HQ will be free to enter the market in its own right.

Figure 1: Summer 2000 New England HHI

Gen.	Mw	%	HHI
BECO	1363	5	25
BHE	249	1	1
CMP	522	2	4
Commonw.	502	2	4
Eastern Util.	518	2	4
FPL	1080	4	16
NBP	700	3	9
NEES	555	2	4
NU	8465	32	1024
Sithe	1983	7	49
Southern Co.	820	3	9
USGen	5119	19	361
Utd. Illum.	1484	6	36
Vt. Group	1181	4	16
Other	2245	8	10
TOTAL	**26786**		**1572**

The total HHI of 1572 places the New England market in the moderately concentrated range, suggesting that there are correspondingly significant grounds for concern with regard to market power as the process of restructuring moves forward.

5. Standard offer HHI. With the beginning of retail access, the Commission is charged with the responsibility of ensuring the availability of standard offer service for customers who prefer not to select their own competitive provider. Pursuant to the restructuring statute, prior to July 1, 1999, the Commission must devise and complete a bid process to select providers for each t&d service territory.[90] The operative date on which the selected standard offer providers would commence service is the date set for implementation of retail choice, viz., March 1, 2000. Thus, in addition to assessing general levels of concentration in the New England market, there is a specific need for assurance that the market will be configured in such a way as to support a competitive bid process conducted in the summer of 1999, for

[90] 35-A M.R.S.A. §3212.

delivery of a significant quantity of power (Commission staff estimates a maximum of 1400 mw), beginning March 1, 2000. Again, Figure 2 below, with minor adjustments, is based on Synapse's analysis. In an effort to arrive at an estimate of the minimum level of competition likely to obtain in this market, we adopt the following conservative assumptions:

- providers must be able to offer a minimum of 100 mw
- all utilities in the region outside Maine are subject to 100% native load obligations
- no scheduled new entry participates[91]
- no NYPP imports are included
- NBP's market share is capped at 700 mw to reflect intertie capacity.[92]

Figure 2: Standard Offer HHI

Gen.	Mw	%	HHI
BHE	249	7	49
CMP	522	16	256
FPL	1064	32	1024
Great Bay	141	4	16
Milford Pwr	149	4	16
NBP	700	21	441
NU	507	15	225
TOTAL	**3332**		**2027**

In this instance, the HHI point total indicates a highly concentrated market. The significance of this figure, however, must be evaluated in light of the purpose of the assessment in this instance: to gauge the level of competition for purposes of a one-time bid process rather than an ongoing market.

The market is configured in a way that may facilitate market power in a bid process. Relatively few players may be able to vie for a significant portion of the State's standard offer

[91] Although four new facilities with total capacity in excess of 1000 mw are scheduled to come on line by the end of 1999, we prefer to assume that none of them will be ready to participate in a bid process by the summer of 1999.

[92] NBP has expressed interest in participating in the standard offer bid process.

business. Furthermore, we have not yet collected available information concerning the production costs of available capacity. This level of competition, therefore, may not be sufficient to enable the Commission to meet the statutory goal of selecting at least three providers of standard offer service for each service territory, without an adverse impact on consumer prices.[93] Of course, the statute permits the Commission to select only one provider in any given territory, if this result will best serve consumer interests. Even so, there is some degree of uncertainty as to whether competition will be adequate to assure a healthy outcome.

Accordingly, the standard offer bid process will bear close watching. Careful reassessment of available uncommitted capacity in the spring of 1999, with attention to its production costs, would be advisable.[94] At this time, however, legislative action does not appear to be warranted. The Commission retains the ability to advise the Legislature of any needed corrective action after the results of the bid are in, pursuant to the statute.[95]

6. Ancillary services HHIs. We have not engaged in an independent assessment of levels of concentration in New England markets for ancillary services. However, we have reviewed the HHI analyses of these markets put forward variously by Dr. William Hieronymus (on behalf of NEPOOL) and Dr. Joe Pace (on behalf of CMP and FPL). The differing results arrived at by these experts are compared in Figure 3 below. The markets analysed include Ten-Minute Spinning Reserve ("TMSR"); Ten-Minute Nonspinning Reserve ("TMNS"); Thirty-Minute Operating Reserve ("TMOR"); Operable Capability; and Automatic Generation Control ("AGC"), also known as load following.

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[93] 35-A M.R.S.A. §3212.

[94] We have not as yet developed the information necessary to review the estimated production costs of the uncommitted capacity which we expect to be available to compete for Maine's standard offer service.

[95] 35-A M.R.S.A. §§3212, 3217.

Figure 3: New England Ancillary Services HHIs

	Hieronymus (1999)	**Pace** (2000)
TMSR	872	2676
TMNS	928	2217
TMOR	1010	1907
Op. Cap.	843	1483
AGC	1447	1962

At first glance, the obvious discrepancy between these results might appear problematic, particularly since Pace's HHIs almost uniformly suggest that ancillary services markets are subject to a high degree of market power. Moreover, an examination of the underlying figures reveals some apparent disagreement between the two experts concerning the precise amounts of capacity likely to be available in New England to provide these services. However, the primary reason why Hieronymus' results are in every case sharply lower than Pace's is methodological. Hieronymus followed a practice of truncating market shares by capping them at the total amount of estimated demand in the relevant market, while Pace did not. As Hieronymus argues:

> Given [a] pattern of excess supply, the true competitiveness of the market is better reflected by a concentration measure that does not artificially overstate the market share of the large suppliers whose potential supply exceeds the total demand in the market. This 'truncated HHI' ensures that the measure of concentration does not reflect redundant capacity and imply market power that does not actually exist, simply because the HHI calculation has been performed mechanically. By truncating the capacity of any supplier at the total market demand (and thus calculating the truncated HHI) the measure of concentration can be made more rational.[96]

Because we agree with the truncation methodology employed by Hieronymus in this instance,[97] we are inclined to accept his assessment to this extent: it seems fair to conclude that the New

96 Hieronymus 29.

97 Truncation may not always be appropriate. If demand levels are fluid and uncertain, as in the renewables market discussed below, this factor should be referenced in the analysis, rather than incorporated into the HHI.

England markets for ancillary services will be no less competitive, and subject to no greater degree of market power, than the energy and capacity markets.[98]

F. Market Power in New England

Our Herfindahl summary of the New England energy market arrives at an HHI result of 1572, indicating a moderate level of concentration. Federal merger guidelines provide that an acquisition which increases an HHI in the moderate 1000-1800 point range by an additional 100 points "potentially raises significant competitive concerns."[99] Similarly, our New England HHI result should be interpreted as justifying potentially significant market power concerns.

However, "market share and concentration data provide only the starting point" for a competitive analysis.[100] The HHI is a screening device, not an absolute indicator of the presence or absence of market power. In this section, therefore, we assess the importance of other factors affecting competition in the New England market which may argue that a greater or lesser degree of market power concern is appropriate. In particular, an analysis of the responsiveness of the New England market to competitive forces, and the impact of anticipated new entry, is offered in the paragraphs following.

1. Responsiveness of the market to competitive forces. Three fundamental facts hold broad implications for the competitive success of the regional wholesale electricity market. First, the persistence of a culture of coordination during the transition to open markets is likely. Second, the oligopoly structure of the New England electricity industry, as currently configured, enhances the risk of coordination and collusion. Third, the New England

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98 Note, moreover, that Hieronymus and Pace agree that entry into ancillary services markets is substantially easier than entry into energy and capacity markets. Hieronymus 39; Pace 15.

99 Guidelines ¶ 1.51 (b).

100 Id. ¶ 2.0

spot market, under proposed rules, may be susceptible to unilateral, as well as coordinated or collusive manipulation to drive up prices. These points are discussed briefly below.

Shaped by a century of regulation and a common commitment to system reliability, the electric industry harbors a culture of coordination and cooperation. In a newly competitive environment, perspectives and motivations formed by regulation may lead to actions which are inappropriate, anticompetitive and in some cases illegal. As FTC Chair Robert Pitofsky recently explained to a Congressional committee:

> because industry participants have become used to a regulated environment, some may attempt to protect or duplicate many of the comfortable aspects of that environment. Where they are accustomed to coordinated interaction and the use of the regulatory process to bar or disadvantage new entry, industry members may attempt to use monopolistic or cartel behavior to protect their entrenched positions after deregulation. A monopolist will not ordinarily welcome new entry, and issues of access or structural realignment to promote access will have to be considered ....[101]

The tactics of coordination and collusion can be employed not only to bar or disadvantage new entry, but also to exercise market power to drive wholesale prices up. In the electric industry, the coordinated or collusive exercise of market power is facilitated by the ready availability of historical and (depending on market design) current data which permit market participants to "draw accurate inferences with respect to each other's pricing strategies and cost structures."[102]

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[101] Prepared Statement of the Federal Trade Commission, Presented by Robert Pitofsky, Chairman, Before the Committee on the Judiciary, U.S. House of Representatives, June 4, 1997, http://www.ftc.gov/os/1997/9706/ electric.htm

[102] R. Pierce, Antitrust Policy in the New Electric Industry (Draft Paper), 44 ("Pierce").

With two players holding an aggregate market share of 50% and four holding well over 60%, it is clear that the New England wholesale electricity market is characterized by oligopoly control.[103] The resulting risk of coordination and collusion is aggravated by a pattern of joint ownership of facilities. Taking account of this pattern of joint ownership, it has been estimated that together, market leaders NU and USGen possess the ability to control or influence the wholesale bids for 65% of the capacity in the market.[104]

Oligopoly control poses a special danger in the context of an electricity spot market, where daily interaction offers ample opportunities for dominant groups to police and enforce collusive arrangements.[105] The principal price-setting mechanism in the New England market will be the spot market be operated by ISO-NE. An oligopolistic industry structure renders this market vulnerable not only to coordination and collusion, but also to unilateral "strategic behavior," or "gaming," designed to maximize profits. Such behavior can take a variety of forms, including "economic withholding," withholding capacity within a constrainable interface, and more complicated strategies, as briefly outlined below.

Under proposed rules, sellers will bid power into the spot market twenty-four hours in advance for each hour of the succeeding day. Currently, no mechanism exists for buyers to place demand-side bids.[106] The market will clear for each hour at the price bid for the last block of power required to meet demand in that hour. All buyers will pay, and all sellers receive, the market-clearing price. In this system, participants with high market share will possess the ability

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[103] W. Shepherd, Monopoly and Antitrust Policies in Network-Based Markets Such as Electricity, 12 (tight oligopoly exists when four firms hold more than 60% of the market).

[104] P. Cramton & R. Wilson, A Review of ISO New England's Proposed Market Rules, September 9, 1998, 8, 23 ("Cramton & Wilson").

[105] Cramton & Wilson, 39.

[106] The ISO has proposed instituting a demand-side bidding mechanism; however, the timing of this needed reform remains doubtful. See discussion below.

to bid so high on a particular facility or block of power as to effectively withhold its capacity from the market, thereby driving up the market-clearing price for all power sold in that hour. This practice, referred to as "economic withholding," could give rise to considerable price volatility. Computerized simulation modeling performed by Synapse Energy Economics demonstrates that if NU unilaterally engages in such economic withholding, the result would be a significant increase in average wholesale clearing prices, perhaps by as much as 10% on an annualized basis. Of course, all sellers would benefit, since all receive the market-clearing price. If two or more market leaders adopted economic withholding strategies, it is likely that sellers would collectively secure an even greater benefit, with a correspondingly greater price impact.[107] These results indicate that in the context of the electricity spot market, where two market leaders control an aggregate 50% of a market with a 1500-point HHI, the market power risks are substantial.

Finally, as NEPOOL acknowledges, an entity which possesses capacity concentrated within a potentially constrainable interface can engage in economic withholding of capacity to create a load pocket and exercise market power within it.[108] Indeed, as a result of the strong "interaction effects" felt across transmission grids, even more complicated strategies may be

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[107] B. Biewald, D. White & W. Steinhurst, Horizontal Market Power in New England Electricity Markets: Simulation Results & a Review of NEPOOL's Analysis, June 11, 1997, 15, Table 1 (computer simulation modeling shows a 29.7% price impact based on strategic withholding by NU; and a 32.1% price impact based on strategic withholding by four market leaders); New England Power Pool, FERC Docket Nos. OA97-237-000 & ER97-1079-000, Testimony of Bruce Edward Biewald on Behalf of the Maine Attorney General, January 23, 1998 (with extreme conservative sensitivity adjustments to the model, strategic withholding by NU and USGen results in a 5.9% price impact); T. Woolf, B. Biewald & D. White, Memorandum: Market Power Analysis of New England Using the ELMO Model, October 29, 1998 (based on updated market share data, modeling shows that NU economic withholding would cause 9.6% price impact; this could be dramatically higher if anticipated new entry fails to materialize).

[108] Hieronymus, 24 -25.

available. For example, a firm might in some circumstances be in a position to exercise market power by increasing production for the purpose of “bottling up” a disproportionate amount of competing generation.[109] At the present time, we simply do not know the extent to which such Machiavellian strategies may be available to dominant players in New England, or to which they could affect wholesale and, ultimately, retail prices in Maine.

2. Impact of new entry. As the Federal Trade Commission correctly emphasizes, “timely, likely and sufficient entry may alter the competitive implications of market structure,” and provide an antidote to market power.[110] Certainly, it is likely that new entry in the New England generation industry will reduce concentration over the next decade. The extent to which such new entry will be sufficient to remedy market power on a timely basis, however, remains in doubt. Federal guidelines consider entry sufficiently easy to constrain the exercise of market power only if entry could be accomplished within two years.[111]

A number of factors have emerged to enhance the prospect that new entry could occur on a significant scale in the region over the next several years. The advent of new combined-cycle gas-turbine technology has reduced both the cost and the time required to effect entry into generation markets. Deregulation of natural gas prices has lowered fuel costs; and the ready

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[109] W. Hogan, A Market Power Model with Strategic Interaction in Electricity Networks, Energy Journal Vol. 18 No. 4, 107 at 109 (firm could exercise market power by increasing production to “bottle up” disproportionate amount of competing generation), 111 (electrons choose their own path in transmission grid, producing “strong interaction effects”), 127 (citing possibility of “cases where with a well-placed combination of plants and constraints, a generation company with market power could act to both raise critical prices and increase its volume by blocking competitive production that amounts to more than its own increase in output”), 130 (adverting to “the ability of 1 mw of incremental generation at one location to block production of more than 1 mw elsewhere”).

[110] Comment of the Staff of the Bureau of Economics of the Federal Trade Commission, May 29, 1998, Maine PUC Docket No. 97 -877 at 3.

[111] Guidelines ¶ 3.2. See EPRI, Technical Assessment Guide, Vol. 1: Electricity supply -1993 (Revision 7), June 1993, Exhibit 23 (preconstruction, license and design time for new generation is two years; construction time is an additional two years).

availability of Canadian gas with the addition of pipeline capacity transiting the region is now a near-certainty.

The result has been an explosion of enthusiasm for the construction of new capacity. Projects totaling nearly 30,000 mw of new, largely gas-fired capacity have been announced on varying schedules throughout the region.[112] If all of these new projects were developed, regional capacity would more than double, resulting in a significant surplus. Much of the announced new capacity would be constructed by new entrants.[113] Moreover, of the roughly 30,000 mw total, as much as 10,000 mw is planned for completion within the next two years.[114] Of this 10,000 mw regional total, it is noteworthy that approximately 2500 mw would be built by new entrants within the State of Maine.

No one expects that all of the announced new capacity will actually be built. The prospect of a significant surplus by itself will surely serve to dampen the ardor of some developers and their financiers. As more new capacity comes on line, late-starting projects will suffer an increasing rate of attrition.[115] Moreover, it is unlikely that there would be enough gas available to support more than half of the announced projects.

Further, the established utilities within NEPOOL have supported policies which, whether by design or otherwise, have impeded the entry of new competitors. In particular, NEPOOL devised an expensive and time-consuming process for considering applications to interconnect with the existing grid, and planned to levy substantial charges against new entrants for arguably

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[112] Interconnection Study Status, http://www.iso.ne.com/transmission_services_and_generation_interconnected /documents/New10/13/98nnections.

[113] Some on the other hand, would be built by participants which already possess significant market share, such as USGen.

[114] I.e., before the end of calendar 2000.

[115] W. Short, Competitive Retail Markets: Tenuous Ground for Renewable Energy (Draft Paper 1998) 5.

unnecessary transmission upgrades purportedly required by their projects.[116] FERC has recently rejected many of these policies, requiring NEPOOL to come forward with new interconnection proposals.[117] When revised NEPOOL proposals are forthcoming, they will merit careful scrutiny to ensure fair treatment of new entrants.

Despite promising signs, therefore, new entry remains something of an imponderable. If (as we assumed for purposes of the above HHI calculations) half of the new capacity scheduled to be in service by the end of 2000 is completed on time, and if this success-rate is maintained in the years ahead, new entry will exert a gradually increasing procompetitive influence in the New England wholesale market. Moreover, if half of the new capacity planned within the State of Maine (i.e., 1250 mw) is constructed within the next two years, the possibility of a southern and central Maine load pocket will all but disappear. However, our HHI and modeling results suggest that, given the current oligopoly structure of the electricity industry in New England, new entry alone cannot be relied upon to provide a sufficient remedy to market power in the short to medium term.

G. Remedies for Market Power in New England

The ability of the Maine Legislature to take remedial action to protect competition in the New England market is limited to the margin. The operation of wholesale electric power markets in interstate commerce and the wholesale rates which prevail in such markets are within the

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[116] See Comments of the Maine Attorney General On the NEPOOL Report of Compliance, August 10, 1998, FERC Docket No. ER98-3853-000.

[117] New England Power Pool, FERC Docket No. ER98-3853-000, Draft Order Conditionally Accepting Compliance Filing, As Modified, And Accepting, In Part, And Rejecting, In Part, Proposed Tariff Changes, As Modified, 8 (NEPOOL evaluation criteria unrealistic and unreasonable), 9 (existing SIS procedures cumbersome and ineffective), 11 (NEPOOL queuing process to be addressed in the context of an upcoming filing) 13 (expansion cost pricing to be addressed in the context of a future NEPOOL filing relating to congestion pricing). As an intervenor in this proceeding, the Department, as well as the Maine Public Advocate, had protested aspects of the NEPOOL compliance filing which unnecessarily raised barriers to entry.

exclusive jurisdiction of FERC.[118] Accordingly, in order to avail itself of appropriate remedies to market power in the regional market, the State of Maine must in most cases pursue and champion those remedies before FERC and, if necessary, in the federal courts. Indeed, to a large extent, such remedies must be sought in the context of a single ongoing proceeding, which will broadly determine the future course of wholesale restructuring in New England. That proceeding is NEPOOL's application to FERC for market-based rate authority, and related dockets.[119]

1. NEPOOL market-based rate application. In the context of federal restructuring of wholesale electric power markets, FERC possesses the power to grant or deny market participants' applications to charge market-based, as opposed to regulated, cost-based rates. To obtain such authorization, market participants must show that they do not possess market power in the relevant market, or that market power has been adequately mitigated.[120]

Initially filed on December 31, 1996, NEPOOL's long-running application for market-based rate authority on behalf of its members, including NU, USGen and others, is still pending. While arguing that none of its participants possessed market power except to a limited extent in potential load pockets, NEPOOL in December 1997 proposed a comprehensive market power mitigation plan ostensibly designed to remedy precisely the type of strategic behavior modeled by Synapse. The NEPOOL mitigation plan would empower the ISO to respond to economic withholding tactics by various means, including imposition of default pricing or limitations on a participant's bid flexibility.[121]

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[118] E.g. Maine Yankee Atomic Power Company v. Public Utilities Commission, 581 A.2d 799, 804 (Me. 1990) (Commission had no authority to require reduction in generator's wholesale rate, set exclusively by FERC; attempt to do so preempted).

[119] New England Power Pool, Market Power Analysis, February 28, 1997, FERC Docket Nos. OA97-237-000 & ER97-1079-000.

[120] E.g. New York State Gas & Electric Corporation, 78 FERC ¶ 61309 at 62326 (1997).

[121] New England Power Pool, Market Monitoring, Reporting, and Market Power Mitigation Proposal, December 19, 1997, FERC Docket Nos. OA97-237-000 & ER97-1079-000.

NEPOOL has also filed a regional transmission tariff and a package of proposed market rules to govern the spot market.[122] In June, 1997, FERC authorized the creation of ISO-NE to manage transmission and dispatch functions.[123] The ISO will also administer the spot market, when its implementation is authorized. However, neither bid-based dispatch nor the spot market can be implemented until FERC rules on NEPOOL's market-based rate application.

Among its other duties, ISO-NE is required to independently assess the competitiveness of the markets it administers.[124] In a recent development, ISO-NE in September 1998 filed a study of the competitiveness of the spot market under NEPOOL's proposed rules.[125] The study finds that significant flaws in the market design advanced by NEPOOL are likely to accentuate market power, and proposes a series of wide-ranging reforms. In particular, the study recommends installation of a multi-settlement system, a location-based pricing congestion management system, and demand-side bidding. It also counsels abolition of capacity trading markets, as well as significant adjustments to ancillary services markets. While endorsing most (but not all) of the study's recommendations, ISO-NE nevertheless advocates full implementation of competitive wholesale markets by December 1, 1998, and apparently continues to support a full grant of NEPOOL's application for market-based rate authority on that schedule.[126]

The Department, the Commission and the Public Advocate have all been active as intervenors in this and related FERC dockets. While committed to the same objective, viz., to protect and promote competition in New England electricity markets, we have adopted somewhat

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[122] New England Power Pool, Restructured Arrangements, December 31, 1996, FERC Docket Nos. OA97-237-000 & ER97-1079-000. There has been a series of supplements to this initial filing.

[123] New England Power Pool, 79 FERC ¶ 61,374 (1997).

[124] Interim Independent System Operator Agreement ¶ 6.4.

[125] Cramton & Wilson.

[126] Motion of ISO-NE To Include Its Market Assessment In Docket and Requesting Order Permitting Market Implementation On December 1, 1998, FERC Docket Nos. OA97-237-000, ER97-1079-000, ER97-3574-000, OA97-608-000, ER97-4421-000 & ER98-499-000.

divergent positions. In general, the Department and the Public Advocate have advocated structural remedies to market power, i.e, appropriate divestitures; the Commission favors a regulatory approach.

More specifically, the Department and the Public Advocate oppose granting NEPOOL or its members market-based rate authority, and oppose market implementation, until (1) NU, USGen and perhaps Sithe divest capacity to reduce market concentration; and (2) critical market reforms proposed by ISO-NE's experts can be put in place.[127] The Department and the Public Advocate lack confidence in the ISO's ability to detect and remedy the exercise of market power under NEPOOL's proposed mitigation plan.[128]

The Commission, joining with other New England commissions, through filings by the New England Conference of Public Utilities Commissioners ("NECPUC"), opposed NEPOOL's initial application on the ground that market power was present, arguing that a mitigation plan was required; NECPUC then played a role in negotiating the plan ultimately adopted and filed by NEPOOL. NECPUC now takes the position that NEPOOL's mitigation plan is generally adequate, and supports market implementation on the schedule proposed by ISO-NE, but asks that FERC require adoption of the market reforms proposed by the ISO's experts by September

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[127] As an alternative, the Department and Public Advocate have submitted that FERC could grant NEPOOL's application in part, and implement markets, while confining NU, USGen and perhaps Sithe to cost-based bids.

[128] Comments of the Maine Attorney General on the NEPOOL Market Monitoring, Reporting & Market Power Mitigation Proposal, January 23, 1998, FERC Docket Nos. OA97-237-000 & ER97-1079-000; Comments of the Maine Attorney General on the NEPOOL Sanctions Rule (Market Rule 13), July 17, 1998, FERC Docket No. ER98-3568-000; Memorandum of the Maine Attorney General & the Maine Public Advocate In Opposition to Motion of ISO-NE To Implement Markets, October 9, 1998, FERC Docket Nos. OA97-237-000, ER97-1079-000, ER97-3574-000, OA97-608-000, ER97-4421-000 & ER98-499-000.

1, 1999. In a separate comment, the Commission has requested that FERC accelerate development of a congestion management system.[129]

At this juncture, several options are open to FERC, ranging from a full grant of NEPOOL's application, and unconditional implementation of the spot market by December 1, 1998, to a denial of the ISO's implementation request, and an order for a full hearing on NEPOOL's application. We cannot predict how FERC will resolve these matters. However, it is certain that market power issues will persist as wholesale restructuring moves forward. The Department and the Commission will continue their efforts to represent the State's interest in these proceedings.

2. Other remedies. Because of federal preemption, the State in most cases lacks jurisdiction to legislatively address market power within a load pocket on the New England grid. It is hoped that the likelihood that a load pocket could arise in southern and central Maine will recede as new entrants within Maine come on line. However, localized load pockets could arise or be created; other strategic actions could be taken which might affect wholesale prices within the State. The Commission and the Department intend to monitor developments, using computerized simulation modeling where appropriate, to ensure as far as possible that anticompetitive activity with a wholesale price impact is detected. To the extent that such price effects are felt, it may be that (as the Federal Trade Commission has pointed out) specific

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[129] Comments of NECPUC On NEPOOL Market Monitoring, Reporting & Market Power Mitigation Proposal, December 22, 1997, FERC Docket Nos. OA97-237-000 & ER97-1079-000; Letter, NECPUC President S. Geiger to FERC Commissioners, October 15, 1998; Answer of NECPUC In Support of Motion of ISO-NE To Include Its Market Assessment In Docket and Requesting Order Permitting Market Implementation, October 13, 1998; Comments of the Maine Public Utilities Commission, ISO-NE's Assessment of the Competition & Efficiency of the NEPOOL Markets, October 13, 1998, all in FERC Docket Nos. OA97-237-000, ER97-1079-000, ER97-3574-000, OA97-608-000, ER97-4421-000 & ER98-499-000.

transmission enhancements or new generation projects can be proposed and encouraged as a practical remedy.[130]

However, where a load pocket arises in all hours for any significant duration, for example as a result of a meteorological event or other emergency, we believe that, for the period during which the connection to the regional grid is severed, interstate commerce and federal jurisdiction are also cut off.[131] It is to be hoped, of course, that such events will be rare. However, recent experience suggests that a month-long load pocket in an isolated section of the State could give rise to serious (even if relatively short-lived) market power concerns. Specifically, a situation could arise where the only generation available within the load pocket would sell only at exorbitant rates.

Accordingly, we recommend that the Commission be empowered to assert jurisdiction over wholesale rates on market power grounds in any section of the State in which a load pocket arises for all hours for more than forty-eight hours.[132]

H. Recommendation

The Commission should be empowered to assert jurisdiction over wholesale rates on market power grounds in any section of the State in which a load pocket arises for all hours for more than forty-eight hours.

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[130] Comment of the Staff of the Bureau of Economics of the Federal Trade Commission, May 29, 1998, Maine PUC Docket No. 97-877 at 8 (using computer simulation modeling of the grid and generation, the Department and the Commission may be able to identify a small, focused list of transmission or generation projects which could alleviate the most significant market power concerns).

[131] See Federal Power Commission v. Florida Power & Light Co., 404 U.S. 453, 463 (1972) (jurisdiction premised on commingling of energy transmitted in interstate commerce, as determined by engineering or scientific test). There could of course be no such commingling when transmission lines are severed.

[132] In addition, we plan further study with regard to the advisability of legislation to provide for civil remedies for an exercise of market power in a load pocket.

V. HORIZONTAL MARKET POWER: NORTHERN MAINE

A. Summary

Northern Maine (Aroostook and parts of Penobscot and Washington Counties) is isolated from the New England grid, and functions electrically as part of the Canadian Maritime control area. It constitutes a separate geographic market for purposes of market power analysis.

The northern Maine wholesale energy market is highly concentrated, and subject to a corresponding degree of market power. The market is dominated by New Brunswick Power Corporation ("NBP"), which controls transmission access to northern Maine. NBP transmission is unsupervised by any regulatory authority, and NBP has set discriminatory rates, with the result that it has preferential access to the market. This transmission regime effectively excludes Hydro-Quebec from the market, as well as participants from New England and Nova Scotia.

In addition, there exists a transmission constraint which prevents firm power from flowing to northern Maine from New England. Moreover, the problem of market power is probably aggravated by the lack of access to a well-designed spot market. Finally, the prospect that new entry will increase competition in northern Maine is minimal.

Under these circumstances, the question whether retail choice in northern Maine should be postponed must be confronted. However, postponement should be a last resort. Other, less drastic remedies, which offer some promise of success, should be implemented in the first instance.

It now appears that the south-to-north constraint can be effectively eliminated by means of a contractual arrangement whereby NBP would supply back-up power and needed ancillary services to the four northern Maine t&d companies. NBP has stated its willingness to enter into such undertakings with the t&ds for a five-year term. We recommend legislation authorizing northern Maine t&ds to contract with NBP, and empowering the Commission to require that the purchased services be passed through to retail marketers at cost.

NBP and provincial New Brunswick authorities indicate that the current transmission regime is likely to be subjected to a legislative overhaul prior to the inauguration of retail choice in northern Maine. However, the timing of New Brunswick’s restructuring remains uncertain. In the interim, it has been proposed that, as with the tie-line interruption and ancillary services, NBP should enter into contracts with northern Maine t&d companies to supply transmission services. It would be preferable if these services were supplied at NBP's lower "out" rate, rather than its higher "through" rate. Again, legislation is recommended. A meeting among the Commission, the Department, NBP and other parties has been scheduled to discuss these issues and arrangements.

The possible creation of a bulk power system administrator (“BPSA”), with or without a spot market, is also under discussion among the Commission, the Department and stakeholders. No consensus yet exists with regard to a workable concept in this area. Accordingly, legislation would be premature. The Commission and the Department will continue to monitor the development of a BPSA, and may offer additional recommendations later.

While transmission enhancements do not appear to be immediately essential to the competitive health of the northern Maine market, such enhancements would certainly be in the long-term interest of northern Maine consumers. The Commission and the Department will continue to monitor projects currently under study, will keep the Legislature informed, and may offer legislative recommendations in due course.

Finally, we recommend that, in view of the high level of market power in northern Maine, and the uncertain efficacy of available remedies, the Commission should be legislatively empowered to impose wholesale rate regulation to the full extent of the State's jurisdiction. We believe that the State possesses jurisdiction to regulate wholesale rates charged in northern Maine by generators located in Canada. Such regulatory power should be used only as a last resort to protect against market power, short of suspending retail choice. Even if never used, this option could provide a useful deterrent to market power abuse.

B. The Geographic Market

Remote from the remainder of New England, northern Maine is characterized by significant special features which demand a separate assessment of market power in energy and ancillary services. The first task in performing such an analysis is to define the geographic market.

The northern Maine electrical grid, which powers Aroostook as well as portions of Penobscot and Washington Counties, is unique.[133] While the remainder of the State is fully integrated into the NEPOOL control area, this tricounty grid functions electrically as a part of the Canadian province of New Brunswick. Moreover, conditions in the northern Maine market contrast sharply with those in the rest of New England. In particular:

- Northern Maine is connected only to New Brunswick; the only existing transmission link to New England (or anywhere else) is through New Brunswick.
- Northern Maine can draw on firm power imports only from Canada, since under current conditions the transmission tie through New Brunswick to New England cannot carry firm power south to north.

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[133] We refer to the Aroostook-Penobscot-Washington County grid below as “the tricounty grid,” “the tricounty area”, or simply as “northern Maine.”

- New Brunswick, which governs much of the control area of which northern Maine forms a part, has no current plan to develop competitive wholesale or retail markets.[134]

- New Brunswick transmission is currently governed by discriminatory policies determined unilaterally by the utility, New Brunswick Power Corporation ("NBP"), an instrumentality of the provincial government which operates free of regulatory oversight by any Canadian or U.S. agency.[135]

- The Maritime control area has no ISO, and no spot market.

New England, by way of comparison, is interconnected to, and can draw on imports of firm power from three other regions, viz., New York, Quebec and New Brunswick. A competitive wholesale market already exists in New England; most states in the region are moving, albeit on different schedules and with varying policies, toward retail choice. Moreover, the NEPOOL control area is governed by FERC's nondiscriminatory, open access transmission regime. New England utilities have transferred control of their transmission systems to ISO-NE, which will operate a spot market for energy and ancillary services, and will be empowered to apply measures designed to prevent or mitigate the exercise of market power.

Northern Maine, then, presents an electrical anomaly. Politically linked to New England, and governed by Maine's restructuring initiative, it is nevertheless isolated from the region by the configuration of existing transmission ties. Electrically connected to New Brunswick, the tricounty area is separated from the province not only by the international frontier, but by contrasting energy policies which make a unified market impossible. There is no escaping the

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[134] The provincial government, however, has initiated a policy discussion concerning restructuring options. D. Savoie & D. Hay, Electricity in New Brunswick and Options for its Future, July 1998 ("Savoie & Hay"), http://www.gov.nb. ca/legis/reports/energ-98/index.htm

[135] Specifically, NBP levies a rate for "through" transmission (for power transiting the province) which is 40% higher than the "out" rate which it charges itself. The NBP "out" rate is 60% higher than rates which apply in New England.

conclusion that northern Maine must be viewed as a geographic market unto itself, separate from both New England and neighboring sections of Canada for purposes of a market power analysis.[136]

Indeed, strictly speaking, northern Maine may constitute not one but two separate geographic markets. This is because the greater part of the territory served by Eastern Maine Electric Cooperative is not connected to the remainder of the tricounty grid except through New Brunswick. Because the market power problems afflicting the two markets are identical, however, they may be treated as one for purposes of this analysis.

C. Concentration Analysis

Having delineated the geographic contours of the northern Maine market, we turn in this section to an assessment of the levels of concentration and competition within it. As in the analysis of the New England market above, we employ the Herfindahl-Hirschman Index ("HHI"), a screening device used by federal antitrust enforcement authorities (as well as FERC) as an indicator of market power. The HHI is the sum of the squared market share percentages of each market participant. The next step, then, is to identify the participants, and determine their market shares.[137] Generating capacity is used as a gauge of the market shares in energy of in-market participants, while tie-line capacity sets an upper limit on the market shares of importers.

In contrast to the larger new England market, which includes a large number of entities possessing varying amounts of generation capacity, northern Maine counts only three or four

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136 The electrical geography of northern Maine is well-described in T.Woolf & B.Biewald, Competition & Market Power in the Northern Maine Market, October 1998, ("Woolf & Biewald") a study prepared for the Commission in response to the legislative mandate of 35-A M.R.S.A. §3206 (3) ("to determine the most efficient and effective means of ensuring that the portions of this State that are currently connected to the New England grid through transmission lines that pass through Canada are connected to the grid in a manner that ensures that customers in those portions of the State are able to take full advantage of retail access"). This section relies in part on Woolf & Biewald's analysis.

137 U.S. Department of Justice & Federal Trade Commission, Horizontal Merger Guidelines, 57 Fed. Reg. 41522 (1992), ¶¶1.3 -1.4 ("Guidelines").

generation companies.[138] Generation capacity in northern Maine is currently divided among MPS, Aroostook Valley Electric Cooperative ("AVEC"),[139] and Alternative Energy, Inc. ("AEI"), approximately as follows:

MPS	--	66 mw
AVEC	--	32 mw
AEI	--	37 mw

In fulfillment of its divestiture obligations under the restructuring statute, MPS has proposed to sell most of its generation assets, including its 33 mw hydropower facility at Tinker Station, to WPS Power Development, Inc. ("WPS"), a Wisconsin company.[140] This proposed acquisition is the subject of a pending proceeding at the Commission. However, MPS also holds a "qualifying facility" contract which entitles it to approximately 18 mw of the capacity of the Wheelabrator-Sherman ("WS") cogeneration facility. This asset will be the subject of a separate sale process. Accordingly, for purposes of a Herfindahl-Hirschman analysis, in-market generation capacity may also be broken out as follows:

WPS	--	48 mw
WS	--	18 mw
AVEC	--	32 mw
AEI	--	37 mw

In addition to in-market generation, of course, a concentration analysis must take account of the ability of competitors outside northern Maine to import power into the region. The transmission capacity of the interties to New Brunswick is 200 mw; however, MPS assumes for planning purposes (taking possible outages into account) that these ties are able to carry only 90

[138] Perhaps the most striking contrast between the tricounty geographic market and the New England market to the south is in terms of size. The peak load in northern Maine, approximately 138 megawatts, represents a tiny fraction (approximately 0.6%) of the corresponding figure for New England.

[139] The proposed acquisition of AVEC by FPL from CMP is currently pending before the Commission.

[140] In fact, the statute does not require divestiture of Tinker Station, which is physically located in New Brunswick. 35-A M.R.S.A. §3204 (1) (C). The proposed sale of the Tinker assets, however, remains subject to Commission approval pursuant to 35-A M.R.S.A. §3508. Maine Public Service Company, Petition for Authorization for Sale of Generating Assets, MPUC Docket No. 98- 584 ("MPS Petition").

mw of power on a firm basis. Accordingly, NBP, which consistently produces a large surplus above provincial needs, would be in a position to import at least 90 mw of firm power into northern Maine.[141]

Under normal circumstances, it might be expected that Hydro-Quebec ("HQ"), which also has a large surplus available for export and is active as a marketer elsewhere in the United States, would also be a significant competitor in the northern Maine market. HQ can gain physical access to northern Maine through New Brunswick. The capacity of interties linking Quebec to New Brunswick is ample, easily exceeding those connecting New Brunswick to northern Maine.[142] This suggests that HQ should be considered a competitor equal to NBP, capable of importing 90 mw into the northern Maine market.[143]

However, there is a serious obstacle to the full participation of HQ in the market. Although it labels its tariff "open access," NBP charges HQ (and others) a rate for "through" transmission service (transiting the province) 40% higher than the rate it charges itself for "out" service (exiting the province). In addition, the through tariff is significantly (120%) higher than those which obtain in NEPOOL. Unlike HQ, NBP conducts no marketing activities in the United States. NBP believes that, in these circumstances, it has no obligation to bring its transmission tariff into conformity with FERC open access standards.[144] Moreover, NBP's transmission fees and policies are not subject to the oversight of any Canadian regulatory body. NBP's transmission

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[141] Woolf & Biewald 8, App. B; see also MPS Petition, Prefiled Direct Testimony & Exhibits of Dr. Richard C. Tabors, Aug. 7, 1998, Exhibits RDT- 2 -3 ("Tabors").

[142] Woolf & Biewald App. A.

[143] It can be debated whether in this scenario, HQ and NBP should be assigned 90 mw or 45 mw each. We adopt the former because it reflects the fact that both entities are able to compete for sales up to the 90 mw limit.

[144] It is not clear that NBP's interpretation is correct in this regard. NBP also argues that, in any event, its tariff is FERC-compliant.

tariff is thus unregulated, discriminatory and subject to unilateral change at the sole discretion of the utility.

HQ refuses to transmit energy across New Brunswick for its own account because, as a condition of such transmission, NBP requires reciprocal access to HQ transmission facilities. Under its own transmission tariff, approved by Quebec's Regie de l'Energie,[145] HQ may not accord such reciprocal access as long as the NBP tariff is unregulated and discriminatory. Accordingly, HQ has no current plans to market power in northern Maine.

Despite its inability to make use of NBP transmission, HQ considers itself free to, and does, enter "buy-sell" contracts with other entities at the Quebec-New Brunswick border. Such indirect sales offer at least the prospect that a marketer other than HQ could use HQ capacity to compete in northern Maine. As long as NBP retains the unilateral ability to set discriminatory transmission rates, however, neither HQ nor a proxy using its capacity can be considered a full competitor in northern Maine for purposes of an HHI analysis.

This same conclusion applies, of course, to any other generator located in Canada, since the only transmission path available to such participants is through New Brunswick. Nova Scotia Power Incorporated ("NSP"), for example, might be considered a potential competitor, although historically it has shown little interest in exporting power, and does not appear to enjoy a consistent surplus. In our view, NSP in any event should be excluded from the concentration analysis for the same reasons as HQ.

Indeed, the same conclusion also applies to all U.S. generators outside northern Maine, since they too must rely on NBP transmission services to reach the market. However, New England generators suffer from an additional handicap. Although the MEPCO line linking New

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[145] The Regie de l'Energie is the provincial regulatory authority in Quebec.

England to New Brunswick is capable of carrying approximately 700 mw, it cannot deliver any firm power south to north.[146] This is because, in the event that NBP's 650 mw nuclear generator at Point Lepreau suffered an unscheduled outage, virtually all the power on the MEPCO line which had been contractually earmarked for the northern Maine market would be siphoned off to serve New Brunswick load. Thus, as a practical matter, NBP holds a call option on most of the south to north capacity of the MEPCO line to protect against the consequences of a Point Lepreau outage. As a result, although they can furnish nonfirm power to northern Maine, New England generators cannot bind themselves contractually to supply firm power to tricounty purchasers, and accordingly, would have to be excluded from the HHI analysis even if New Brunswick adopted a regulated, nondiscriminatory transmission regime.[147]

Against this background, we offer the following HHI data.[148]

Figure 4: Current HHI for Northern Maine

Gen.	Mw	%	HHI
MPS	66	29	841
AVEC	32	14	196
AEI	37	16	256
NBP	90	40	1600
TOTAL			**2893**

Figure 4 above depicts the current market, prior to any MPS divestiture; it would also accurately describe the market after approved sale to WPS of all MPS assets, including the WS entitlements. Figure 5 below (which also provides the basis for Figure 6 below), assumes approval

[146] Woolf & Biewald 9; Central Maine Power, Request for Approval of Sale of Generation Assets, Prefiled Testimony and Exhibits of David M. Conroy, Feb. 20, 1998, 6, Maine PUC Docket No. 98 -058.

[147] For this description of the south-north stability constraint on the MEPCO line, we are indebted to Commission staffer Norman Leonard.

[148] These HHI results are very close to those arrived at in Woolf & Biewald App. B. Table B.1, scenarios 1 & 2; slight discrepancies appear to result from different methodology for rounding. In his testimony on behalf of MPS, Dr. Tabors arrived at much lower HHIs for the current market because he erroneously included HQ and NSP (in one scenario) as well as Westcoast Power and Tractebel (in another). Tabors, Exhibit RDT-2. Our reasons for excluding HQ and NSP from the analysis are addressed above; we discuss the entry prospects of Westcoast and Tractebel below.

of the proposed sale to WPS, with sale of the WS entitlements to a different purchaser. In each of Figures 4 and 5, the total HHI indicates an extremely high level of concentration, giving cause for serious concern with regard to market power.

Figure 5: Base HHI for Northern Maine

Gen.	Mw	%	HHI
WPS	48	21	441
WS	18	8	64
AVEC	32	14	196
AEI	37	16	256
NBP	90	40	1600
TOTAL			**2557**

Although the Commission could achieve a reduction in this elevated HHI on the order of 150 points by ordering WPS to spin off certain assets acquired from MPS in the context of the pending divestiture, it is clear that this would be insufficient to allay market power concerns. Only if a means can be found to effectively include both HQ and NEPOOL in the market will the HHI decline significantly, as illustrated in Figure 6 below.

Figure 6: Northern Maine with HQ & NEPOOL Participation

Gen.	Mw	%	HHI
WPS	48	12	144
WS	18	4	16
AVEC	32	8	64
AEI	37	9	81
NBP	90	22	484
HQ	90	22	484
NEPOOL	90	22	484
TOTAL			**1757**[149]

Even with the participation of HQ and NEPOOL, the HHI remains disquietingly high. Although significantly abated, market power concerns will persist until neighboring Canadian markets are effectively restructured and opened to competition. Bearing in mind that, in any case,

[149] Compare Woolf & Biewald, App. B, Table B.1, scenarios 4 & 5; Tabors, Exhibit RDT-2, Scenario 1998: Present Market.

the HHI serves as a screening device rather than an absolute indicator, we turn in the section following to an analytical assessment of the seriousness of the market power problem in northern Maine.

D. Market Power in Northern Maine

Analysis of concentration based on current conditions in the northern Maine market yields an HHI result in excess of 2500. This indicates a high degree of market power. Moreover, it is not difficult to discern that this market power resides principally in NBP. NBP's market dominance is both horizontal, deriving from its ability to offer a large block of surplus power to the northern Maine market; and vertical, based on its ability to effectively exclude other potential competitors through its unilateral, unregulated control of transmission through the province.

Federal antitrust authorities describe markets with an HHI above 1800 as "highly concentrated." In such markets, a merger which produces an increase in the HHI of 100 points or more is presumed "likely to create or enhance market power or facilitate its exercise."[150] This presumption may be overcome by a showing that other factors render the creation, enhancement or facilitation of market power unlikely. There are two primary factors to be considered: first, the relative risk that the market may be unresponsive to normal competitive forces as a result of coordination, collusion or for other reasons; and second, the countervailing prospect that new entry could undermine market power and increase competition.[151]

In this report, our focus is not on the competitive effects of a particular proposed acquisition or merger, but rather on the northern Maine's readiness for competitive markets, based on current conditions. The analysis, however, is the same. In the paragraphs below, therefore, we examine the likelihood that market power in northern Maine could be enhanced by

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[150] Guidelines ¶1.51 (c).
[151] Id. ¶¶2 -3.

coordinated interaction among market participants or other factors; and the extent to which new entry may be relied upon to counteract market power.

1. Responsiveness of the market to competitive forces. Hitherto subject to comprehensive regulation, the electric industry is a relative newcomer to competition. The need to ensure system reliability, among other factors, has accustomed the industry to a high degree of coordination among firms. Old habits often die hard. It is likely that there is a substantially increased risk of habitual coordination, and perhaps an augmented tendency to illegal collusion as well, in a previously regulated, newly competitive industry.[152]

In northern Maine, the risk of coordination and collusion is likely to be greater in inverse proportion to the small number of market participants. An additional factor to be considered is NBP's current policy determination that it will not market electricity for its own account within the United States.[153] Open access rules may well require NBP to alter its discriminatory transmission rate structure, eliminating most or all of the discrepancy between its "through" and "out" tariffs.[154] As a result, while it remains willing to sell power to U.S. marketers at the frontier, NBP will not itself deliver power within the United States. If NBP were to contract to deliver power at the border to an entity which was already a participant in the northern Maine market as a generator, competition in the wholesale market could be significantly reduced. Under these

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[152] Prepared Statement of Robert Pitofsky, Chairman, Federal Trade Commission, Hearing Before the Committee on the Judiciary, U.S. House of Representatives, 105th Congress, First Session, June 4, 1997 (some industry participants, accustomed to coordination, may attempt to conserve comfortable aspects of a regulated environment; would not discount the possibility of cartel behavior to protect entrenched positions); see also, R. Pierce, Antitrust Policy in the New Electricity Industry, 44 (increased risk of collusion, since electric wholesalers know all about each other's price strategies and cost structures).

[153] In a conversation with the Department on July 29, 1998, Darrell Bishop, NBP Director of Bulk Power Marketing, stated that "reciprocity is a concern" and that as a result, NBP has no current plans to market power at retail in Maine.

[154] Federal Energy Regulatory Commission, Order No. 888.

circumstances, the already high concentration index reported above might represent a serious understatement.[155]

Equally significant, perhaps, is the risk that the market could suffer from rigidity, and might lack the ability to respond to competitive signals. Currently, northern Maine lacks access to an auction market. The primary trading mechanism is likely to be bilateral contracts. These may be supplemented by spot transactions if northern Maine gains ready access to the spot market to be administered by ISO-NE, or develops its own. Although not a panacea,[156] access to a well-designed spot market would probably increase the responsiveness of the northern Maine market to competitive forces.[157]

2. New entry. Significant difficulties confront the developers of the many projects to construct new generation facilities now on the drawing board in New England. There is a real probability, however, that some fraction of these projects will be built, and that some new entry will occur. Whether this prospect is likely to be realized on a sufficiently accelerated schedule to mitigate market power in the short or medium term remains an open question.[158]

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[155] Such a contract would merit careful analysis to determine whether it violated the prohibition against contracts or combinations in unreasonable restraint of trade. 10 M.R.S.A. §1101. Accordingly, NBP may wish to seek the informal approval of the Department before entering into a contract of this nature.

[156] As we discuss in the section relating to horizontal market power in New England above, spot markets may also fall prey to market power. There is even greater reason for concern with regard to strategic behavior (economic withholding) in a northern Maine spot market than there is in the much less concentrated New England market. See Petition of Maine Public Service Company for Authorization for Sale of Generating Assets, Maine PUC Docket No. 98 -584, Testimony of Dr. Aleksandr Rudkevich On Behalf of the Maine Public Advocate, Part II ("Rudkevich").

[157] See Woolf & Biewald, 14 ("spot market provides greater opportunities ... to participate in the market, and to reach a large number of customers easily and quickly. A spot market provides electricity buyers greater opportunities for purchasing the lowest-cost electricity at all times. A spot market also provides real-time, consistent, reliable and transparent information about market prices and conditions, thereby promoting efficient market behavior [citation omitted]").

[158] See discussion above.

In northern Maine, by contrast, the issue is whether there is likely to be any new entry at all. No new projects are currently on the drawing boards.[159] Northern Maine will not have access to the natural gas pipelines which will provide fuel to new entrants elsewhere in New England. Moreover, northern Maine is an unattractive venue for the construction of new generation capacity because of its remote geography and its dependence on NBP's high-priced transmission services and unilaterally-determined, discriminatory rates. In addition, the lack of access to a spot market may make it more difficult for new entrants to contemplate participating in the northern Maine market.[160]

The prospect of new entry from New Brunswick is also discouraging. Under New Brunswick's Electric Power Act, NBP enjoys the exclusive right to generate power in the province. Private developers must obtain special authorization from the Lieutentant-Governor in Council to construct or operate any generation facility with a capacity greater than 500 horsepower.[161] In the recent past, for example, Fraser Paper Company received such authorization to construct a 38 mw cogeneration plant, whose output is fully contracted to NBP.

More recently, and more significantly for present purposes, Westcoast Power has obtained the requisite gubernatorial authorization to move ahead with a project to repower a 250 mw unit at NBP's oil-fired Courtenay Bay facility (near St. John) to accommodate natural gas. An optimistic schedule would bring this facility on line by late 2000. With NBP as minority partner, Westcoast will hold an 80% controlling equity stake in the project, and plans to market electricity in New England. This could include sales into northern Maine. However, the project's output is

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[159] Although the Loring Development Authority is currently attempting to auction a mothballed 40 mw coal-fired generator (capable of conversion to oil) at the former air base, it remains to be seen whether there will be any takers.

[160] Woolf & Biewald, 14.

[161] New Brunswick Electric Power Act §§ 32 (1) through 32 (4).

already fully contracted to NBP for five winter months each year.[162] Accordingly, the ability of this project to alleviate market power pressure on northern Maine is limited, even if Westcoast's Courtenay Bay operations are kept strictly independent of NBP.[163]

While another gas-fired project, in northern New Brunswick, is in the early stages of discussion and preparation, this project has not yet received gubernatorial authorization, and appears to be subject to significantly greater contingencies, including the construction of a 150-mile lateral gas pipeline. It is unclear whether NBP would have an equity position in this project, which is planned for a site adjacent to NBP's existing coal-fired facility at Belledune. In any event, the developer, Tractebel Power Inc., expects to market all of its planned 350 mw in New England, and has no present intention to compete for sales in northern Maine.[164]

In sum, the prospects for new entry into the northern Maine market are poor. In light of this assessment, it becomes critical that effective remedies for market power be found before the inauguration of retail choice in northern Maine.

E. Remedies for Market Power in Northern Maine

Under current conditions, the wholesale electricity market in northern Maine is extremely concentrated, indicating a high degree of market power. In the microcosmic tricounty environment, there is a danger that coordination, collusion and, not least, a lack of market flexibility will further undermine competition. The prospect of new entry is limited and unreliable. A lack of competition at the wholesale level is likely to have an adverse impact on retail prices.

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[162] Maine Public Service Company, Response to Houlton Water Company's Data Request No. 1, Maine PUC Docket No. 98 -584, Sept. 16, 1998 , Question HWC-01-06.

[163] Westcoast may have difficulty obtaining FERC authorization to charge market-based rates, in view of the 20% NBP stake, and NBP's discriminatory transmission regime.

[164] Based on a conversation between the Department and Robert Dubois of Tractebel, September 29, 1998.

Under these inauspicious circumstances, it may be questioned whether Maine should act legislatively to postpone retail choice in the northern section of the State.

Before embracing this course of action, however, the Legislature should give due consideration to the feasibility and efficacy of other available remedial measures. Accordingly, in the paragraphs below, we review Maine's jurisdictional ability to promote: (a) an emerging solution which offers the prospect of moving firm power north from New England along the MEPCO line; (b) the transition to a regulated transmission regime in New Brunswick; (c) access to a spot market for tricounty purchasers; (d) construction of alternative transmission connecting northern Maine to New England and Quebec; and (e) interim wholesale price regulation as a last resort short of suspending retail choice.

1. How northern Maine can obtain firm power from New England. On September 11, 1998, NBP signed a contract to supply MPS with "tie line interruption service," or back-up power. The power will be supplied on an as-needed basis, without the need to reserve capacity, at a price equal to 120% of cost. The contract expires on February 28, 2005. Access to this back-up power will ostensibly enable MPS to enter contracts to sell firm power in northern Maine on the basis of nonfirm imports from New England over the MEPCO line.[165]

In a subsequent meeting with the Commission and representatives of the Executive Branch, NBP made known its willingness to enter into similar contracts, for a similar term, with any party.[166] NBP has since confirmed this offer in separate conversations with Woolf & Biewald,

165 Administration Committee Agreement, Maine Public Service Company-NB Power, Tie Line Interruption Service, dated August 25, 1998.

166 The meeting took place in Bangor, September 17, 1998, and was attended by Gregory Nadeau, Assistant to the Governor, Thomas Welch, Commission Chair, Stephen Ward, Public Advocate, Gordon Weil, consultant to the Public Advocate as well as Houlton Water Company and Van Buren Light & Power District, Laurie Lachance, State Economist, and Peter Louridas, MPS. Attending from New Brunswick were Don Barnett, Assistant Deputy Minister for Energy, Jocelyne Mills, Department of Intergovernmental & Aboriginal Affairs; and for NBP, Archie Gillis, Senior Vice President, Stewart MacPherson, Vice President Corporate Affairs, Bill Marshall, Director, Strategic Planning, and Darrell Bishop, Director, Bulk Marketing.

and with the Department.[167] Further, NBP has indicated its willingness to similarly contract to supply needed ancillary services, viz., Automatic Generation Control ("AGC", or "load following"), Ten-Minute Spinning Reserve ("TMSR"), Ten-Minute Nonspinning Reserve ("TMNS") and Thirty-Minute Operating Reserve ("TMOR") to all comers.[168] If NBP follows through on this offer, the effect will be to give any party interested in marketing power in northern Maine the ability to do so on the basis of nonfirm imports from New England over the MEPCO line, backed by NBP's "tie-line interruption service" together with needed ancillary services. This prospect, if realized, would effectively remove the south-to-north constraint on the MEPCO line, and significantly improve northern Maine's access to generators in New England.

NBP's offer is obviously a very significant development, and clearly indicative of very considerable goodwill on the part of our Canadian neighbors. However, by itself, NBP's offer remains insufficient to provide a reliable link to New England. Except insofar as it is now contractually committed to provide back-up power (though apparently not ancillary services) to MPS, NBP has as yet placed itself under no obligation to follow through on its offer. While we are confident that NBP means what it says, we submit that the State of Maine cannot make fundamental policy decisions with regard to restructuring in northern Maine on the basis of mere representations.

NBP's offer provides a valuable opportunity, which should be welcomed and acted upon. The State should seek a way to respond positively to NBP, and to devise a mutually acceptable means to transform its nonbinding offer into something more solid. For example, the State might,

[167] Woolf & Biewald 26. In a conversation with the Department on September 24, 1998, Darrell Bishop of NBP reiterated NBP's offer to contract to supply back-up power to any entity.

[168] Specifically, in response to a question from consultant Gordon Weil at the September 17 meeting, Darrell Bishop stated that NBP would provide load following and all ancillary services needed. Because of the south to north constraint, AGC, TMSR and TMNS from New England are unavailable to northern Maine on a firm basis. NBP's market power in these products is, accordingly, extremely elevated; the proposed contracts would, however, adequately mitigate that market power.

through legislation, authorize all northern Maine t&ds to enter into contracts with NBP for "tie-line interruption services" and needed ancillary services for a five-year period.[169] The legislation could further empower the Commission to require the t&ds to provide the back-up power and ancillary services supplied by NBP pursuant to these contracts to any marketer seeking to import power into northern Maine from New England, at the t&d's cost. It would then remain for NBP to actually enter into such contracts with the t&ds.[170] The contracts could then be presented for the Commission's approval.

This mechanism would limit NBP's costs by requiring only four contracts, instead of a multiplicity of transactions. In addition, requiring contracts with the t&ds rather than marketers brings the back-up power and ancillary services within Maine's regulatory jurisdiction. If NBP (or MPS) retained the ability to select which marketers would receive these essential commodities, and to determine their price, the problem of market power would remain unsolved. Adoption of the legislative measures described above is therefore strongly recommended.

2. The prospect of a regulated transmission regime in New Brunswick.

With these contracts and the related legislation in place, a significant link to New England would have been forged. Nevertheless, the prospect of NBP wielding market power in northern Maine will remain as long as NBP retains the unregulated, unilateral ability to set discriminatory transmission rates.

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[169] The northern Maine t&ds include MPS, Houlton Water Company, Eastern Maine Electric Cooperative, and Van Buren Power & Light District. Note that the legislative changes needed for the latter three, which are consumer-owned utilities, may differ somewhat from those relating to MPS. It may be questioned whether NBP should expect to profit from these transactions to the extent of the 20% markup reflected in the MPS contract. It can be argued that NBP derives an uncompensated benefit from the its ability to draw on MEPCO in the event of an outage at Point Lepreau. It is this benefit to NBP which causes the constraint on the MEPCO line, and prevents firm power from reaching northern Maine from New England. By providing back-up power and ancillary services to northern Maine, the argument runs, NBP is merely balancing the account.

[170] NBP Director of Strategic Planning Bill Marshall indicated at a meeting at the Commission on November 12, 1998 that NBP had no conceptual difficulty with this proposal.

The problem is straightforward: NBP, and jurisdictionally, the province of New Brunswick, control the only existing transmission route linking northern Maine to New England, Quebec, Nova Scotia, and more distant points. NBP's strategic control of this transmission route is not tempered by regulation of any kind, U.S. or Canadian, federal or provincial. Currently, NBP is exercising that control to impose discriminatory rates. Specifically, the "through" transmission service offered to marketers transiting the province is approximately 40% higher than the "out" rate which NBP charges itself for transmission exiting the province.[171] Theoretically, there is nothing to prevent NBP from acting unilaterally to further increase its "through" transmission tariff to any level it wishes. In sum, NBP possesses the ability, should it so desire, to exclude competing New England, Quebec or Nova Scotia generation from the northern Maine market.

In practical terms, the situation is more complex. There are signs that NBP, and provincial authorities, are moving toward a regulated regime. It is significant, for example, that (a) NBP has posted its transmission tariff on the Internet using FERC's OASIS information system; (b) NBP represents publicly that its through and out rates are cost-based;[172] and (c) in response to "concerns expressed by potential transmission customers," NBP has publicly pledged that any increase in its tariffed rates "shall not be greater than the rate of inflation as measured by the Consumer Price Index in New Brunswick until such time [as] an independent regulatory body having jurisdiction over the tariff is put in place."[173] Finally, NBP and provincial government

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[171] We doubt that this discriminatory regime would pass muster under FERC open access rules.

[172] In conversations with the Department on June 5, June 8, and July 29, 1998, Darrell Bishop and Arden Trenholm of NBP stated that the wheeling tariffs were cost-based. NBP apparently justifies its discriminatory rate structure by asserting that only importers derive benefit from the tie lines connecting New Brunswick to New England and other regions. NBP denies that it also derives benefit, despite the undeniable fact that, in the event of a Point Lepreau outage, the New Brunswick system would draw heavily on the MEPCO tie.

[173] Tariff Clarification, February 27, 1998, http://oasis.nbpower.com/WhatsNew. Of course, the pledge remains unilateral, and could be withdrawn, but is unlikely to be withdrawn lightly. Indeed, NBP has reportedly indicated (per consultant Gordon Weil) that it will waive the escalator and freeze transmission rates.

officials have indicated to the Commission and representatives of the Executive Branch their belief that provincial legislation subjecting NBP transmission rates to independent regulatory oversight is likely to be in place by the summer of 1999.[174]

These are encouraging signs. In addition, the Commission and the Department will continue to explore whether there is any prospect that NBP would subject itself to FERC open access standards by applying to that agency for market-based rate authority. This step would offer a dual benefit for Maine: in addition to nondiscriminatory transmission rates through the province, it would also permit NBP to enter retail markets in northern Maine (and other sections of the State as well) as a marketer in its own right. The Commission and the Department in any event will continue to carefully monitor, and inform the Legislature concerning, further developments in this area.

In the meantime, pending either an NBP FERC filing or provincial legislation or both, an interim solution to the problem of NBP's unregulated, discriminatory transmission regime has been proposed. The proposal is straightforward: in addition to contracting with northern Maine t&d companies to provide tie-line interruption and needed ancillary services, NBP should also offer to contract with the t&ds to provide transmission services at a fixed price. Preferably, the agreed price should be a rate equal to NBP's lower "out" rate, rather than its higher "through" rate.[175] In effect, NBP could elect to treat northern Maine as if it were a part of New Brunswick for transmission purposes. Again therefore, there is a need for legislation authorizing the t&ds to enter into these transmission services contracts subject to Commission approval, and empowering

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[174] This representation was made at the September 17 meeting. In a conversation with the Department on September 24, 1998, Darrell Bishop confirmed this, and indicated that June, 1999 was the target date for the passage of legislation in this regard.

[175] It is not clear whether this change would satisfy the conditions imposed on HQ by its own tariff, thereby permitting it to serve northern Maine directly.

the Commission to require the t&ds to pass the transmission services on to marketers at cost. Adoption of these measures is strongly recommended.[176]

3. Access to a spot market. Northern Maine has no ISO, and no spot market. Development of an ISO to govern transmission in the New Brunswick and northern Maine and Maritime region would certainly represent a desirable antidote to NBP's vertical market power astride regional transmission routes. An ISO could also function, as in New England, as the administrator of a regional spot market. However, an ISO for the Maritime region is not likely to be developed in the immediate future. If such an institution does eventually come into being, it will be as an element of a regional restructuring process. The policy discussion which could lead to that process has only just begun in New Brunswick.[177]

During the summer of 1998, a "Northern Maine Working Group" ("NMWG"), comprising NBP and the northern Maine t&ds, was formed to study options for northern Maine pending creation of a regional Maritime ISO. In this context, NBP has indicated that although it is not yet prepared to discuss formation of an ISO, it would consider cooperating with MPS and other utilities in northern Maine to set up a "bulk power system administrator" ("BPSA") which, among other functions, might operate a day-ahead spot market.[178]

Most recently, MPS offered that it would function as the BPSA, and would operate a spot market modeled as closely as possible on the New England market.[179] However, both the

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[176] The proposal originated with consultant Gordon Weil; NBP is aware of it. A meeting among NBP, the Commission, the Department and other stakeholders to discuss the overall contractual approach to tie-line interruption services, ancillary services and transmission services has been scheduled for December 16 -17, 1998.

[177] See Savoie & Hay.

[178] See Memorandum, W. Gerow to Northern Maine Working Group on Settlement, August 17, 1998 (at working group telephone conference on August 13, 1998, NBP "took exception [to] use of the term ISO", and to "the notion that we were talking about the Maritime Control Area as a whole").

[179] See Northern Maine BPSA Draft Framework Document (undated, without attribution). This was presented by Fred Bustard of MPS at a meeting between representatives of NMWG, the Commission and the Department on November 12, 1998.

Department and Houlton Water Company ("HWC") have voiced concerns with respect to this concept.[180] In particular, both the Department and HWC expressed the view that a BPSA operated by MPS might not be sufficiently independent; both were also concerned that emulation of the NEPOOL market system may not be appropriate in the northern Maine context.

Computer simulation modeling suggests that strategic behavior, or gaming, may drive up wholesale prices in the New England spot market. Recent testimony before the Commission on behalf of the Maine Public Advocate indicates that such behavior will pose an even greater problem in the more concentrated, microcosmic northern Maine environment.[181] It may be that northern Maine is too small to support its own spot market, and that this should await regional restructuring which includes New Brunswick and Nova Scotia, or enhanced transmission connecting northern Maine to New England.[182]

It is our understanding that the NMWG has engaged expert consultants to advise it with regard to available BPSA options. The Commission and the Department look forward to working further with NMWG to develop a settlement system appropriate to northern Maine's special circumstances. In due course, when a workable concept has been developed and agreed upon, there may be a need for legislation. The Commission and the Department will keep the Legislature informed in this regard.

In the meantime, what is essential is that northern Maine have access to a spot market capable of receiving and transmitting price signals, and lending flexibility to the market. If NBP binds itself to provide back-up power, ancillary services and reasonably-priced transmission

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[180] Letter, J. Clark to F. Bustard dated November 13, 1998; Letter, F. Ackerman to F. Bustard dated November 13, 1998.

[181] Rudkevich, 2 (generation owners could achieve very significant market power by capacity withholding).

[182] See FTC Attorney Warns Of Single State ISO, Restructuring Today, Oct. 8, 1998 (J. Hilke quoted to the effect that a single state ISO is too small -- with very few, if any exceptions -- because “it may not encompass enough generating firms to mitigate generator market dominance problems and enhance reliability”).

services to all northern Maine t&ds, the beneficial influence of New England spot market pricing will be felt in northern Maine.

4. Alternative transmission. The benefits of retail choice in northern Maine cannot be assured unless more reliable access to New England generators, as well as to HQ generation and the New England spot market, can be provided. As we conclude above, the requirement of access to New England, and perhaps Quebec as well, can be adequately fulfilled if NBP commits itself: (a) contractually to supply back-up power and needed ancillary services to all northern Maine t&ds, thereby effectively eliminating the south to north constraint on the MEPCO line; and (b) to fair, nondiscriminatory transmission rates.[183] If NBP and the provincial government take both of these actions (as they have indicated they will), there will be good grounds for optimism with regard to the competitive health of northern Maine markets.

Another way to provide northern Maine with access to Quebec and New England generation sources would be through the construction of new transmission lines. Alternative transmission which would remove the MEPCO constraint, or bypass New Brunswick, would clearly offer long term benefits. If events unfold positively, there should be no <u>immediate</u> need to construct alternative transmission lines linking northern Maine to Quebec and New England. However, alternate transmission remains an important long-term option. Moreover, if NBP's cooperation cannot be secured, or experience demonstrates the persistence of market power problems despite such cooperation, it may become necessary to focus more intensively on this option.

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[183] Whether contractually, or by means of a filing with FERC or appropriate provincial legislation establishing an independent, regulated, nondiscriminatory transmission regime.

The Commission and the Department will therefore monitor and continue to inform the Legislature concerning (a) feasibility studies being conducted by Transenergie[184] with regard to a proposed transmission line which would connect HQ directly to MPS through Madawaska; and (b) BHE plans for a new line connecting NEPOOL to NBP as an alternative to MEPCO.[185] Although not immediately essential, it is clear that the construction of each of the proposed new lines would enhance the competitiveness of northern Maine markets. In due course, if necessary, the Department and the Commission may recommend legislation to promote the completion of these or other transmission projects.

5. Wholesale price regulation. We currently expect that it will prove possible, with the anticipated cooperation of NBP, to overcome the south-to-north constraint on the MEPCO line, thereby permitting NEPOOL participants to effectively enter the northern Maine market. In addition, the prospect for transition to a regulated, nondiscriminatory transmission regime in New Brunswick in the near to medium term appears promising. However, these developments are largely outside Maine's jurisdictional control, and cannot be assured.

If neither of these hoped-for developments is realized, northern Maine's wholesale market will remain extremely concentrated, and subject to a high degree of market power. As we have noted, it may be questioned whether, in these circumstances, retail choice should proceed as scheduled in the tricounty area. If wholesale prices rise in a concentrated market, there would almost certainly be an adverse price impact on retail prices as well. To guard against this eventuality, as a final remedial measure short of postponing retail choice, we submit that the Legislature should authorize the Commission to impose wholesale price regulation on the northern Maine market, if warranted, to the full extent of the State's jurisdiction.

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[184] Transenergie is HQ's transmission subsidiary.

[185] BHE proposes to sell its rights in this regard as part of the proposed divestiture to PP&L.

The precise extent of Maine's jurisdiction to regulate wholesale rates in northern Maine is less than crystal clear. Certainly, FERC possesses plenary and exclusive authority to regulate wholesale rates with respect to transactions entered upon by public utilities (i.e., the owners of jurisdictional facilities) in interstate commerce.[186] See, e.g. Nantahala Power & Light Co. v. Thornburg, 476 U.S. 956, 966 (1986); Maine Yankee Power Company v. Maine Public Utilities Commission, 581 A.2d 799, 803 (Me. 1990).

The Supreme Court has held that the Federal Power Act "grants [FERC] jurisdiction of all sales of electric energy at wholesale in interstate commerce not expressly exempted by the act itself." Federal Power Commission v. Southern California Edison Company, 376 U.S. 205, 210 (1964). Strikingly, there is an express exemption which would appear to be tailor-made for northern Maine's special circumstances. A subsection added to the Federal Power Act by a 1953 amendment provides:

> The ownership or operation of facilities for the ... sale at wholesale of electric energy which is ... generated in a foreign country and transmitted across an international boundary into a State and not thereafter transmitted into any other State, shall not make a person a public utility subject to regulation as such .... The State within which any such facilities are located may regulate any such transaction insofar as such State regulation does not conflict with the exercise of the Commission's powers under or relating to subsection 202 (e).[187]

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[186] The Federal Power Act, 16 U.S.C. §824d, requires that all rates received by a public utility for the sale of energy subject to FERC jurisdiction be just and reasonable. Under a coordinate provision, 16 U.S.C. §824 (b), FERC possesses jurisdiction over all facilities for transmission or wholesale sale of energy in interstate commerce, but not over facilities for generation, local distribution or transmission in intrastate commerce. A public utility is defined as any person owning such jurisdictional facilities. 16 U.S.C. § 824 (e). Transmission in interstate commerce occurs when energy is transmitted from a state and consumed outside that state, but only to the extent the transmission occurs in the United States. 16 U.S.C. § 824 (c).

[187] 16 U.S.C. § 824a (f). The subsection referred to as section 202 (e), 16 U.S.C. § 824a (e), requires that a permit be obtained from FERC prior to any export transmission.

This language explicitly exempts a category of energy producers from FERC wholesale rate jurisdiction, viz., those who generate power in a foreign country, transmit it into a state "and not thereafter ... into another State." There may be entities -- for example NBP and WPS[188] -- which generate power in Canada, and transmit it across the frontier into northern Maine for wholesale and ultimately retail disposition there, with no prospect that it will ever reach New Hampshire or any other U.S. jurisdiction. It would appear that the Federal Power Act expressly places such transactions within Maine's regulatory jurisdiction.[189]

As a practical matter, the ability of the Commission to impose effective price regulation would be constrained not only by production costs, but also by prevailing prices in southern New England markets. However, wholesale regulation tempered by reference to New England pricing would be appropriate in any case in that it would mimic the price effect on northern Maine of effective access to the New England market.

Wholesale rate regulation would be available to the Commission only as a last resort, to combat market power. Such residual regulatory authority should not in any way discourage new wholesalers or generators from participation in the region. If exercised, its practical effect would be no more than to limit market participants in northern Maine to the profit levels they might expect to realize in New England. Yet even if it is never exercised, its availability can operate as an important deterrent to market power abuse in northern Maine.

F. Recommendations

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[188] Tinker Station, currently the subject of a proposed divestiture by MPS to WPS, is located in New Brunswick.

[189] We are investigating whether certain intrastate wholesale transactions within northern Maine may also be subject to state regulation. Specifically, where an intrastate sale for resale made by an entity without interstate facilities involves no amount of energy from out-of-state sources, the transaction may be subject to Maine's jurisdiction. See California Edison, 376 U.S. at 209 fn. 5 (if any amount of out-of-state power reaches the wholesale buyer, the sale is subject to FERC jurisdiction, using an "engineering and scientific rather than a legalistic or governmental test").

1. The Legislature should authorize northern Maine t&d companies to enter contracts with NBP for at least a five-year term for the purchase of back-up power, needed ancillary services and transmission services; and empower the Commission to require northern Maine t&d companies to pass such back-up power, ancillary services and transmission services through at cost to retail marketers and other customers.

2. The Legislature should empower the Commission to impose wholesale price regulation in northern Maine, if warranted by market power concerns.

VI. MARKET POWER IN RENEWABLES

A. Summary

Maine's restructuring statute requires energy marketers to demonstrate, as a condition of licensing, that at least 30% of their supply portfolio for sales in Maine consists of renewable resources (as defined in the statute). This so-called Renewable Portfolio Standard ("RPS") creates a product market distinct from generic energy. Two geographic markets are analysed here for the presence of market power in renewables: New England and northern Maine.

The northern Maine market is highly concentrated; the New England market moderately so. In each case, a current condition of oversupply operates to negate market power. However, there is a potential for increased demand for renewables in the region, and the current oversupply may prove transitory.

If the supply picture tightens, market power could become problematic in both markets. The principal threat is that of vertical retail exclusion: participants holding high market shares in renewables would become the gatekeepers to Maine's retail energy markets, selecting or vetoing their retail competitors, and determining the prices at which they could compete. This threat is accentuated by a lack of flexible mechanisms for trading renewables, such as tradable credits, or a power exchange.

We recommend that the Commission be legislatively empowered to suspend or reduce the RPS in any section of the State on market power grounds.

B. Product and Geographic Markets

Maine’s restructuring statute requires that, as a condition of licensing, competitive electricity providers demonstrate that no less than 30% of their portfolio of supply sources for retail electricity sales in the State are accounted for by renewable resources as defined in the statute. The statute defines the term “renewable resource” as

> a source of electrical generation that generates power that can be physically delivered to the control region in which [ISO-NE] has authority over transmission and that ... qualifies as a small power production facility under [applicable FERC rules] ... [or] qualifies as a qualifying cogeneration facility under [applicable FERC rules] and was constructed prior to January 1, 1997; or ... [w]hose total power production capacity does not exceed 100 megawatts and that relies on one or more of the following: (1) Fuel cells; (2) Tidal power; (3) Solar arrays and installations;

> (4) Wind power installations; (5) Geothermal installations;
> (6) Hydroelectric generators; (7) Biomass generators; or
> (8) Generators fueled by municipal solid waste in conjunction with recycling.[190]

This so-called "Renewable Portfolio Standard", or "RPS," effectively results in the creation of a product market distinct from energy, capacity and ancillary services. As a result of the RPS, the wholesale market for renewable energy must be separately analysed for the presence of market power.

Under the Commission's proposed rulemaking,[191] the appropriate geographic markets in which to assess wholesale market power in renewables are New England and northern Maine.[192] If the Commission had chosen to implement a system of tradable renewable credits,[193] the effect would have been to combine the New England and northern Maine markets. However, the Commission instead selected a contract path tracking mechanism, requiring that energy used to satisfy the RPS be "physically delivered to," and "recognized as serving electricity load" within, either of two control areas, New England and the Maritimes (within which northern Maine is located).[194]

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[190] 35-A M.R.S.A. § 3210 (2).

[191] Renewable Resource Portfolio Requirement (Chapter 311), Maine PUC Docket No. 98 -619 ("Renewable Rule").

[192] In view of the fact that compliance is measured over a twelve-month period, a load pocket would have to affect a significant number of hours over a full year in order to affect the delineation of the appropriate geographic market in which to assess market power.

[193] A tradable credit system would have involved the creation of a secondary market in renewable "tags", where the renewable attribute of energy generated from a specific facility could be sold separately from the energy itself. The Commission's proposed rule rejects tradable credits primarily on the ground that such a system would be incompatible with regional efforts to implement uniform consumer disclosure requirements. See Regulatory Assistance Project Issues letter, May 1998; T. Austin, D. Moskovitz & C. Harrington, Uniform Disclosure Standards for New England: Report & Recommendation to the New England Regulatory Commissions, October 6, 1997.

[194] Since electrons are themselves untraceable within a given grid using current technology, contract path tracking follows the paper trail left by electricity sales to determine the source of the electrons. This contrasts with a tradable credits system, which would track only the separately sold renewable tag or attribute of renewable energy. See Renewable Rule ¶ 4(B).

The proposed rule does not combine the two markets, since a marketer active, for example, only in northern Maine (and not in southern and central Maine) must shop for renewable resources deliverable to northern Maine, and would be affected by the level of concentration and market power which obtained in that market. However, the rule mitigates market power to some extent by allowing a marketer active in both markets to satisfy the RPS on the basis of the statewide average of its renewable resource component. While this is beneficial from the perspective of marketers active in all sections of the State, it does not change the fact that northern Maine and New England continue to require separate analysis for market power in renewables.

C. <u>Concentration Analysis</u>

In this section, we apply a Herfindahl-Hirschman analysis to evaluate levels of concentration in relevant renewables markets.

1. Market participants. All renewable capacity in each market is included in our HHI analyses. Recent or pending divestitures in the New England market (USGen acquisition of NEES assets; FPL acquisition of CMP assets) and northern Maine (WPS acquisition of MPS assets) are reflected. However, to attempt to account for NU's recently announced intention to divest certain capacity in Connecticut and Massachusetts would be speculative.

BHE, CMP and MPS continue to hold certain NUG contracts which are the subject of a sale process separate from the pending acquisitions of generation assets by PP&L, FPL and WPS, respectively. A rulemaking with respect to that process is currently pending at the Commission. While the HHI should therefore ascribe these assets to BHE, CMP and MPS, in evaluating the results, account should be taken of the fact that the Commission retains the ability to require piecemeal sales of the NUGs on market power grounds.

We allow for a moderate level of imports from NYPP. However, there are good grounds to exclude from the HHI calculations all renewable capacity which might appear to be available from Quebec. Currently, HQ exports to the U.S. are drawn from system surplus. Although it possesses approximately 659 megawatts of hydroelectric capacity in facilities under the 100 mw statutory ceiling, HQ faces regulatory barriers which will likely prevent this power from being marketed in New England on a resource-specific basis.[195] In a telephone conference with the Department, a senior HQ executive explained that small, low-cost hydro cannot be removed from the system mix without an impact on the Quebec rate base. As a result, she stated, “HQ does system power sales, not unit contracts .... We are not going to dedicate these units to export.” Any change in this system was characterized as “highly unlikely.”[196]

NBP's ability to earmark qualifying resources for export appears doubtful for similar reasons. In any event, it appears that NBP possesses a relatively limited stock of renewable capacity.[197]

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[195] In particular, such resource-specific exports would be inconsistent with the terms of HQ's current export licenses, issued by Canada's National Energy Board. Further, dedication of particular resources to export would require a ruling by Quebec’s Regie de l'Energie, the provincial regulatory authority.

[196] The quotations are from Johane Meagher, speaking in the course of a telephone conference with the Department and its consultants on June 11, 1998. Meagher also noted that the interties connecting Quebec to New England are fully booked through 2001, with the exception of transmission through New Brunswick, which HQ eschews for policy reasons (discussed above). Following the call, HQ provided data by fax indicating that hydro qualifying under the Maine RPS represents approximately 3.3% of the HQ system mix. Although HQ system exports qualify to this extent under the Maine RPS and the proposed rule, we nevertheless exclude them from the HHI because HQ cannot market its system mix as a qualifying renewable.

[197] In telephone conversations and fax communications with the Department on June 5 and June 8, 1998, Darrel Bishop, NBP Director of Bulk Power Marketing, listed 89 mw of qualifying NBP hydropower. He also referenced certain other hydro units under contract to NBP (approximately 25 mw); and some thermal capacity. It was not clear that any of the thermal capacity would be considered renewable under the statutory definition.

Finally, the ability of New England renewable resources to gain access to northern Maine is uncertain. The MEPCO constraint presumably does not affect the ability of northern Maine marketers to obtain renewables from New England on an interruptible basis, and such imports could be counted toward the twelve-month 30% requirement. Nevertheless, New England renewables remain dependent on NBP's unregulated transmission regime for access to northern Maine. As we indicate above, however, it now appears that the prospects for opening northern Maine to sales from New England are favorable.

2. HHI data. In light of the foregoing, we offer the following HHI data.[198] Two HHIs are offered to provide perspective with regard to northern Maine, reflecting the uncertain participation of New England imports in this market.

Figure 7: Northern Maine Renewables

Gen	Mw	%	HHI
AVEC	30	25	625
AEI	37	31	961
MPS	18	15	225
WPS	33	28	784
TOTAL	**118**		**2595**

Figure 8: Northern Maine Renewables with New England Imports

Gen	Mw	%	HHI
AVEC	30	20	400
AEI	37	25	625
MPS	18	12	144

198 These are based on the workpapers of Bruce Biewald and Timothy Woolf. Note that while at least one expert suggests that HHIs should be truncated to cap market shares at the level of estimated demand, we believe this would be inappropriate, in this instance. The level of demand for renewables is fluid and uncertain. Accordingly, demand and supply dynamics should be considered in evaluating HHI results, rather than incorporated into them. See CMP Request for Approval of Sale of Generating Assets, Prefiled Testimony & Exhibits of Joe D. Pace, February 20, 1998, Maine PUC Docket No. 98 -058 at 25-27.

WPS	33	22	484
NEPOOL	30[199]	20	400
TOTAL	**148**		**2053**

[199] This table shows a single New England participant, capped at 30 mw (one-third of available tie capacity into northern Maine from New Brunswick, reflecting the 30% RPS). If a second New England importer is added, the HHI drops further, to 1769.

Figure 9: New England Renewables

Gen	Mw	%	HHI
BHE	108	3	9
BECO	361	11	121
CMP	486	14	196
Com. Energy	230	7	49
FPL	353	10	100
Indeck	52	2	4
NU	799	24	576
USGen	468	14	196
Vt. Group	220	7	49
Other[200]	299	9	13
TOTAL	**3376**		**1313**

3. Northern Maine concentration. Assuming no New England or New Brunswick participation, northern Maine counts only four generation providers in a position to compete for wholesale renewable sales. The HHI of 2595 indicates a high level of concentration, and a corresponding degree of market power. However, it now appears possible that New Brunswick will submit its transmission regime to regulatory oversight or contractual obligations prior to the inauguration of retail choice in Maine on March 1, 2000. This would give northern Maine some assurance of access to New England renewables imports. The participation of one New England provider would reduce the HHI by 500 points; the addition of a second New England competitor, or New Brunswick participation, would reduce the HHI below 1800 points. Federal authorities consider a market with an HHI below 1800 to be moderately concentrated.

4. New England concentration. The 1313-point New England HHI shown above indicates a moderate level of concentration, and a corresponding degree of market power.

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[200] This category includes an assumed 200 mw of available NYPP imports.

This may understate the actual degree of concentration, since a significant amount of the New England capacity available to meet Maine's RPS is handicapped by high production costs.[201] Such high cost capacity offers less than fully effective price competition.[202]

D. Market Power In Renewables

Under federal guidelines, HHI figures provide a basis for no more than a presumption of market power, to be confirmed or dissipated upon consideration of other factors which may render the creation, enhancement or facilitation of market power more or less likely. In an analysis of the degree to which moderate-to-high levels of market concentration in renewables in northern Maine and New England should give rise to market power concerns, four principal factors merit attention. These are:

- The relationship between demand and supply
- The risk of retail exclusion
- New entry prospects
- The effect of the Commission’s proposed rule for implementation of the RPS.

These points are discussed in the paragraphs below.

1. Demand and supply. Some experts take the view that there will be a large surplus of supply over anticipated demand for renewables. If it is sufficiently large, such a surplus could have the effect of negating horizontal market power.

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[201] See F. Cummings, Impacts of Maine Portfolio Requirement on Supply and Demand for Renewable Resources, September 21, 1998 (study commissioned by Union of Concerned Scientists) ("Cummings") 3. Cummings estimates that as much as 1200 mw of renewable capacity falls into this high-cost category. Note that the same also appears to be true (perhaps to a lesser degree) in northern Maine.

[202] On the other hand, account should also be taken of the fact that the market shares of market leaders NU and CMP will decline over time as the NUG contracts they currently hold expire. However, it is believed that the effect of such contract expirations will be minimal in the first three years of retail choice. For example, CMP NUGs will decline by only 31.77 mw in the first three years, out of a total of approximately 486. See CMP Response to IECG Data Request No. 2, Maine PUC Docket No. 97 -523.

Dr. Joe D. Pace, a consultant to CMP and FPL in proceedings relating to their proposed asset transaction, calculates that Maine demand for renewables as defined in the statute will be at the level of approximately 630-690 mw. Our own calculations agree generally with this estimate.[203] However, Pace overestimates the New England capacity available to meet this demand. Apparently counting many resources which in our view do not qualify, Pace finds between 4962 and 5723 mw of available renewable capacity.[204] Our assessment, by contrast, suggests approximately 3376 mw are available in New England. With respect to northern Maine, it appears that approximately 118 mw of supply are available to meet 44 mw of demand.

While noting that renewable portfolio requirements in other states in the region "could tighten up the supply picture," Pace does not attempt to estimate the extent of this impact, on the ground that to do so would be too speculative.[205] However, today, both Massachusetts and Connecticut have RPS provisions in place. These two provisions differ widely from each other and from Maine's RPS. One commentator estimates that the Massachusetts and Connecticut provisions together are likely to result in a level of demand equivalent to Maine's RPS; the basis for this estimate is unclear.[206] In addition, an increasing level of consumer demand for renewables will be generated by green marketing efforts; however, it is difficult to predict with any assurance how successful those efforts are likely to be.

In sum, it would appear that although there is likely to be some surplus of supply over demand for renewables in these markets, the extent and duration of that surplus is uncertain. Accordingly, although a significant initial mitigating effect appears likely, current estimates of oversupply cannot be relied upon to adequately resolve long term market power concerns.

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[203] Pace 25; see also Cummings.

[204] Pace Exhibit D.

[205] Pace 27.

[206] Cummings, Figure 1.

2. Vertical retail exclusion. In both northern Maine and New England, the principal market power threat is on the vertical, rather than the horizontal plane. This is the danger of retail exclusion.

The RPS has the effect of making participants with high renewables market shares the gatekeepers to Maine's retail market. Any marketer wishing to enter Maine's retail electricity market must obtain a 30% portfolio of renewables in the wholesale market. If a group of participants with a high aggregate market share should hoard renewable capacity, the result would be to effectively exclude would-be entrants from the Maine retail market. This could severely limit retail competition.

It is difficult to gauge the importance of this risk of retail exclusion based on the current configuration of the market. Our HHI results suggest that five New England competitors will hold an aggregate share in excess of 70% of available renewable capacity. In northern Maine, there may be no more than five competitors in all. In the short term, a significant surplus of renewable supply may be sufficient to allay concerns with regard to retail exclusion. In the longer term, in view of the potential for increased regional demand for renewables, the threat of retail exclusion cannot be ignored.

The threat is accentuated in a market lacking liquidity and flexibility. Renewables markets contrast sharply with other energy markets in one important respect: they lack flexible trading mechanisms. The Commission has rejected tradable renewable credits.[207] Moreover, ISO-NE has

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[207] Tradable credits would have added flexibility to the market, but would not necessarily have prevented hoarding. The Commission's determination to use a contract path approach, rather than tradable credits, was based in part on its conclusion that consistency across New England was important. Other New England states favor contract path tracking.

no plans to play any role in administering a regional renewables spot market. While there may be some prospect that private renewables exchanges will arise (as they have in California),[208] until they do, entrants into Maine retail markets will have to satisfy their 30% RPS requirement on the bilateral contract market. Some of these contracts are likely to be long term undertakings. A problem of availability could arise, ossifying the wholesale market.

Worse yet, exclusive reliance on bilateral contracts as a trading mechanism could cause the renewables market to evolve in an anticompetitive direction, concentrating even greater control in the hands of a few dominant players, and according participants with high market share the ability to select or veto their retail competitors, and to control the levels and prices at which they are able to compete.

3. New entry prospects. Most planned new entry in New England is gas-fired generation, which, broadly speaking, is not renewable.[209] No new entry is expected in northern Maine. Although the Massachusetts and Connecticut RPS laws contain provisions designed to encourage new renewable development, it is likely that the scale of such development in the short and medium term will be modest. The Maine statute will not have the effect of encouraging new entry in the renewables market.[210] Certainly, new entry should not be counted on to play a major role in mitigating market power in renewables markets.

4. Effect of proposed renewables rule. Conscious of the pitfalls facing renewables markets, the Commission has endeavored to craft a rule for implementation of the

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[208] See The APX Green Power Market, http://www.energy-exchange.com/html/apx_green.htm. In a telephone conversation with the Department on July 22, 1998, Jack Ellis, executive vice president of APX, indicated interest in opening a private energy exchange in New England, but expressed concern that New England may not be receptive to such an initiative. In any event, the task of private exchanges will be complicated by the divergence of state RPS requirements in the region.

[209] In fact, new gas-fired generation does not qualify in Maine (grandfathered gas-fired cogeneration does); however, gas-powered fuel cells do qualify in both Massachusetts and Maine.

[210] Cummings and Biewald agree on this point.

RPS which, as far as possible within the confines of the law as enacted, can assist in mitigating market power. Specifically, the rule measures compliance over a twelve-month period. In addition, it provides for a further one-year cure period, allowing a competitive provider additional time to make up any deficiency. As an encouragement to new entry, the cure period may be extended when the provider is able to show that it possesses an entitlement to energy from a renewable facility that will be in service within two years and whose output will allow for compliance. In addition, the Commission reserves the discretion to sanction noncompliance by means of a required "optional payment," in lieu of license revocation. The payment, based on the per-kilowatt hour cost of compliance, would go to a fund for renewable resource r&d. Finally, the Commission retains the ability to waive sanctions altogether if it finds that the "provider made good faith efforts but could not reasonably satisfy the portfolio requirement due to market conditions."[211]

These regulatory provisions allow the Commission the flexibility to address the effects of an exercise of market power that may occur in an individual case. They do not, however, represent an adequate long term solution for retail market exclusion, in the event this should become a systemic market power problem.

E. <u>Remedies for Market Power in Renewables</u>

It is probable that the moderate to high levels of concentration and market power in northern Maine and New England renewables markets are adequately mitigated by the current condition of oversupply. However, as growing demand takes up the slack of oversupply, market power may begin to pose a serious threat. The greatest risk is in the vertical dimension: the possibility that overconcentration and inflexibility in wholesale markets for renewables will have

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[211] Renewable Rule ¶ 6. In order to be eligible for the cure period, the provider must show at least 20% of sales served by renewables.

the effect of constricting entry into, and competition within, Maine retail energy markets generally. However, as supply tightens, horizontal market power could also threaten competition in northern Maine, or in New England.

In view of this analysis, we recommend a limited legislative measure which would permit the Commission to take appropriate action in the event that the market power problems which we discern begin to result in actual disruption of markets. Specifically, the Legislature should empower the Commission to suspend or reduce the percentage of the RPS in any section of the State on market power grounds. In the meantime, the Commission will explore the options for development of a publicly or privately administered renewables spot market or exchange, and will investigate the possibility of setting up a limited bulletin board or clearinghouse system to provide an interim mechanism for trading renewables as defined in the Maine RPS.

Another important remedial measure is open to the Commission without the need of legislation: to require piecemeal sales of NUGs in the context of upcoming proceedings. The analysis offered above suggests that this option merits consideration.[212]

F. Recommendation

The Legislature should empower the Commission to suspend, or reduce the percentage of, the RPS in any section of the State, on market power grounds.

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[212] Currently, the CMP NUGs represent the second largest block of renewable capacity in the market. Requiring sale in two segments would reduce the HHI by an estimated 100 points. Piecemeal sale would also reduce the risk of retail exclusion.

VII. CONCLUSION

Maine's electric industry restructuring initiative offers significant potential benefits: lower consumer prices for electricity, and the more generalized economic benefits which flow from competitive energy prices. However, vertical and horizontal market power pose a serious threat to the success of this endeavor. Unless the threat is effectively countered, the potential benefits of restructuring could be reduced or lost.

This report analyzes the nature of the market power threat, and considers available remedies. Because Maine is part of regional, and, to some extent, international, electricity markets, the jurisdictional ability of the Maine Legislature to provide adequate remedies for market power in all its aspects, and thereby ensure the success of restructuring, is limited. Where state jurisdiction exists, we recommend certain statutory adjustments to enhance protections against market power abuse. To the extent that market power problems are subject to federal or Canadian jurisdiction, the Commission and the Department are committed to, and have been active in, advocating for open, competitive markets and additional protections against market power.

In this report, we recommend adjustments to the restructuring statute as follows:

- the code of conduct and market share limitation governing marketing by transmission & distribution ("t&d") company affiliates should be reinforced as a means to provide additional protection against vertical market power

- the Commission should be empowered to assess against the t&d and its affiliate the cost of enforcement resulting from violations of the code of conduct and market share limitation

- the Commission should be empowered to impose wholesale rate regulation on market power grounds (a) in a load pocket which arises in all hours for more than 48 hours; and (b) in northern Maine

- northern Maine t&d companies should be authorized to enter contracts with New Brunswick Power Corporation ("NBP") for the purchase of back-up power, needed ancillary services and transmission services

- the Commission should be empowered to require northern Maine t&ds to pass back-up power, ancillary services and transmission services purchased from NBP through to their customers at cost

- the Commission should be empowered to suspend or reduce the Renewable Portfolio Standard in any section of the State on market power grounds.

Electricity markets in Maine, or of which Maine forms a part, are evolving rapidly. As restructuring moves forward, the Commission and the Department may have occasion to offer additional legislative recommendations. In particular, we plan to consider:

- whether experience with the statutory compromise permitting t&d affiliates to engage in retail marketing warrants further legislative adjustment

- whether specific legislative initiatives should be proposed to promote demand elasticity as a means to combat market power

- whether legislation is necessary to facilitate the emergence of an appropriate bulk power administration system for northern Maine

- whether legislation is necessary to facilitate the development of specific transmission or generation projects as a means to mitigate market power.

- whether legislation to provide for civil remedies for an exercise of market power in a load pocket is advisable.

While not without its risks and challenges, electric restructuring has the potential to bring substantial benefits to Maine consumers and the Maine economy. The Commission and the Department look forward to working with the Joint Standing Committee on Utilities and Energy, and with the Legislature as a whole, to do all that we can to make this promise a reality for the people of our State.

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