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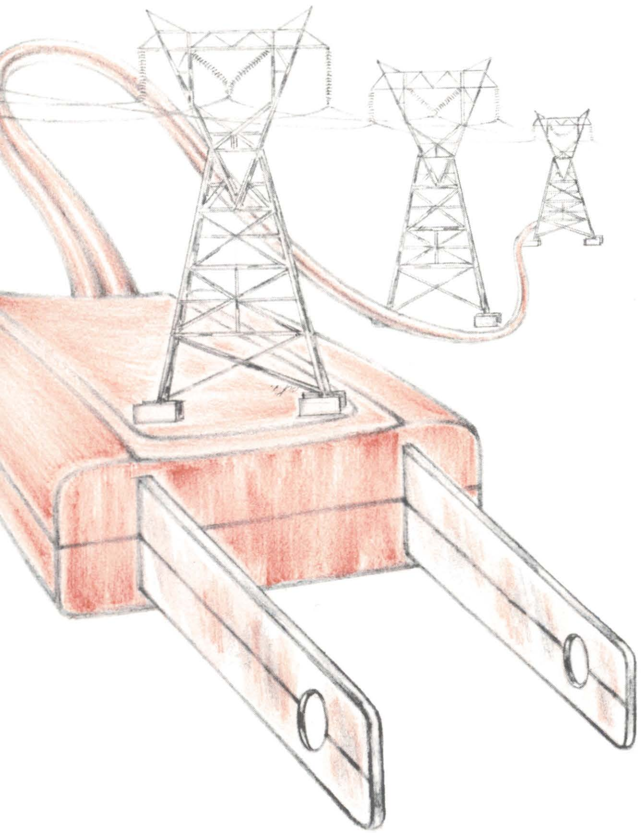

New England's Power Developments:

Part I . . . the private utility industry

The region's growing power needs and efforts to stimulate even greater growth have brought forth bold new plans and proposals from both public and private sectors of the electric utility industry. This article reviews the present utility systems and their plans for the developing market.

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The New England electric utility industry is in a period of rapid growth. Since 1945 the annual peak demand has more than tripled — to *8 million* kilowatts in 1965. The projected peak for 1985 is about *27 million* kilowatts. Such growth and the prospects ahead have caused a decided change in the industry's planning and operations, and more changes are in the making. But, while past and projected growth in demand is comparable to the United States experience as a whole, power rates in New England remain relatively high and energy consumption relatively low.

As a result, new proposals have been advanced from outside the industry's private sector to help bring rates down and increase energy use. One proposal, advanced by Vermont's Governor Hoff, as a member of the New England Governors' Conference, would tap Canada's vast hydro resources for import and area-wide distribution throughout New England. Another, the proposed Maine Power Authority, would offer large-scale atomic-electric development to Maine and neighboring states. A third, the Yankee-Dixie scheme, would bring power to New England from the coal fields of northern Appalachia. Finally, the Federal Dickey hydro project in northern Maine would make a block of energy and peaking power available to the area.

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Existing privately owned systems, now supplying 97 percent of the load, have their own plans to lower rates and increase energy consumption. Moreover, utility managements feel their plans will be carried out at lower cost and with greater reliability of service for the region than any of the new proposals. Their plans, and the current state of the systems on which they build, are analyzed in this issue. A succeeding issue will examine the new proposals as alternatives or as increments for serving the developing power needs. Some plan or combination of plans is optimal for the region. The region should do its best to seek that optimum.

Industry Structure

Dating from 1882 when Thomas Edison's 120-kilowatt Pearl Street Station in New York City began serving a one-square-mile area, early production of commercial power throughout the country was small-scale and its distribution was of necessity local. By the turn of the century, with advancing technology in steam-electric production and particularly with the development of the transformer which made transmission practical, the expansion of single-company service areas was rapid, and by the 1920's a widespread consolidation of local properties into large utility systems was underway. Here in New England, waterpower was a dominant force in early development, and hydro-electric energy production from the region's dispersed watercourses became a natural source of local power supply for early electric light companies and industry. Perhaps for other reasons unique to the Yankee community, besides its geography, small hydro and steam power systems under separate ownership and localized management persisted in New England beyond the wave of corporate integration elsewhere. To a degree, they remain a characteristic of the industry today.

This is not to say that the industry here has not been altered. From a high of nearly 400 privately and publicly owned operating companies in the twenties, the number declined steadily over the succeeding three decades. Still, we begin 1966 supplied by 39 privately owned operating companies generating power in 73 thermal and 93 hydro plants. There are 26 municipal and three rural electric cooperative systems generating all or part of their own needs in 38 small plants, and 88 municipal and rural distribution systems that purchase all requirements from other suppliers. Meanwhile, self-supply by industrial plants remains high compared to other regions, with over 100

TABLE 1

Major New England Systems and 1964 Electric Operating Revenues

New England Electric System	$185,868,000
Boston Edison Company	147,494,000
Connecticut Light and Power Company	96,928,000
Hartford Electric Light Company	63,260,000
Central Maine Power Company	53,735,000
United Illuminating Company	53,130,000
Public Service Company of New Hampshire	41,923,000
Western Massachusetts Companies	38,791,000
Eastern Utilities Associates	38,315,000
New England Gas and Electric Association	34,577,000
Central Vermont Public Service Corporation	15,835,000
Holyoke Water Power Company	10,938,000
Bangor Hydro-electric Company	10,267,000
Green Mountain Power Corporation	7,721,000
Maine Public Service Company	6,063,000

thermal and hydro plants and 777,000 kilowatts total capacity. The six-state supply, augmented by imports from New York and New Brunswick, reached a capability exceeding 9,000,000 kilowatts in 1965. In the systems supplying the public, there are some massive new boilers and some proud old tea-kettles. The average size of all stations is about 50,000 kilowatts, and many of the nearly 300 thermal units still in use are under a thousand kilowatts.

Fifteen major systems have emerged through consolidations, acquisitions, and mergers as the principal suppliers now serving about 97 percent of the regional electric load. They are ranked in Table 1 by 1964 electric operating revenues. New England Electric System (NEES), a holding company, controls four operating utilities. Similarly, Eastern Utilities Associates (EUA) and New England Gas and Electric Association (NEGEA) each control four operating subsidiaries. Yankee Atomic Electric, a separate wholesaling company not listed, is jointly owned by 10 of the major systems. Three of these — Connecticut Light and Power, Hartford Electric Light, and Western Massachusetts Electric — have agreed to form Northeast Utilities, a holding company parent to the three operating companies. Upon Federal approval under the Holding Company Act, Northeast Utilities will become the largest electric system in New England.

In recent years, power supply on a regional basis has assumed prime importance for this traditionally high power cost area, as pressures for cost and rate reduction have intensified. In the early postwar period, supply problems inherited from World War II and antecedent conditions of the 1930's found most companies in need of plant and equipment modernization. But modest technological advances, diversified ownership, avoidance of interstate commerce and attendant Federal rate regulation, and caution in the face of uncertain market growth delayed significant changes in the production pattern.

Since the mid-fifties, a pronounced change has been underway in power system planning, development and operations, stemming from intersystem coordination initiated during wartime and since greatly expanded, plus a clearly accelerating load growth. Since 1955 the average size of thermal unit *added* to the 15 major systems has been 126,200 kilowatts, 10 most recent additions averaged 190,000 kilowatts, and a 600,000-kilowatt unit is now on order. Boston Edison's 400,000-kw New-Boston Unit #1, now on the line, represents in a single machine more capacity than the total of the company's additions over a 30-year period from 1915 through 1945. One of the largest stations — NEES's 500,000-kw Brayton Point station near Fall River — achieved in 1964 a heat rate of 8776 btu per kilowatt-hour from its two machines and was the most efficient station in the entire United States, burning only 10 ounces of coal per kilowatt-hour. Today, 45 percent of thermal capacity in the 15 systems is less than 10 years old. More important, these are the units that produce baseload output, contributing an even higher percentage to energy generation than to capacity. The role of short-term peak-hour supply is relegated to the older units and the hydro plants.

New England's oldest power producer is still important. Hydro's "fuel" is the virtually free and inexhaustible runoff of the watershed, and the flexibility of hydro — quick, inexpensive startup and shutdown by the opening and closing of water gates — makes it ideally suited for short-term peaking. Hydropower also remains an asset in isolated areas of light load density. Some large plants have been installed in recent years in such areas, others are being redeveloped, and other sites remain undeveloped. Nonetheless, the old hydroplants are expensive to maintain and parts are hard to come by, so the small ones are being retired. Two companies, Public Service of New Hampshire and Central Maine Power, are putting reservoirs for small hydroplants to a higher use by selling them at a token sum to the State or to towns for continued use by another burgeoning industry — recreation. And a newer form of hydro — pumped storage — may hasten the demise of some surviving remnants of the region's earliest energy source.

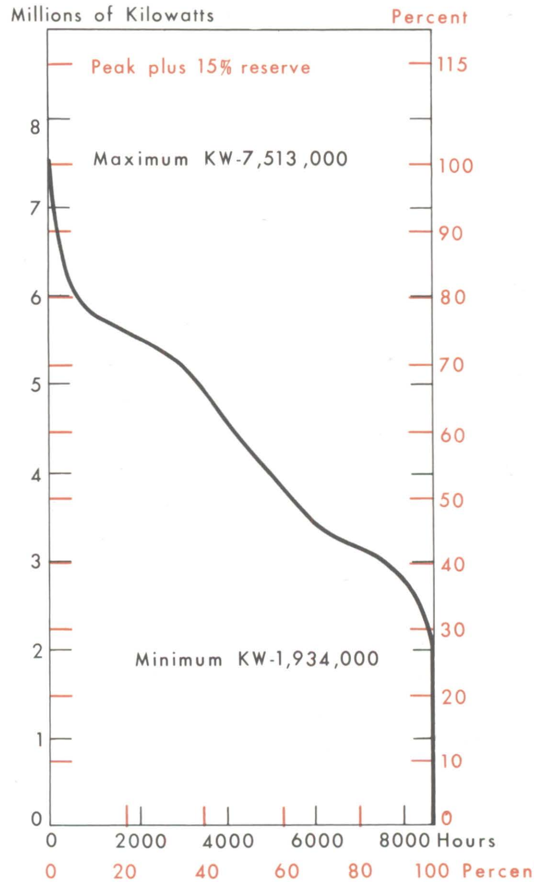
Market Structure

Three basic charateristics of the power market — load factor, load composition, and load distribution — and their underlying trends have significant implications for supply planning, system operations, production costs, and customer rates. Load factor indicates average use of demand relative to maximum use during a time period and is as important to electric utilities as fully loaded flights are to the airlines. Load building efforts of utilities are directed as much to improving load factor as to increasing total demand itself. In addition to a fixed demand or readiness-to-serve charge, most rate schedules contain successively lower energy charges tailored to promote greater use of demand. In this way, fixed capacity may be more fully utilized, unit costs lowered, and rates adjusted accordingly.

The peak demand for kilowatts in New England—the load which systems must stand ready

FIGURE 1

1964 LOAD DURATION CURVE INTERCONNECTED NEW ENGLAND SYSTEMS



to serve at all times and in all forms — is increasing at a rate of about 6.5 percent annually. The noncoincidental peak on all systems (excluding self-generated industrial load) reached a high of 8,100,000 kilowatts in the Christmas week of 1965. Energy consumption — the use over time of kilowatts of power demanded — was 40,700,000,000 kilowatt-hours in 1965. Annual load factor — the ratio of average load supplied to peak load during the year — was 57.4 percent. While the national average of other systems throughout the industry is currently about 65 percent and in a rising trend, New England's load factor on the average has remained stable for the past decade. The percentage difference seems slight, yet a 7-percent improvement in New England's annual load factor by 1980 would represent a yearly increase in sales of 12 billion kilowatt-hours.

Figure 1 shows the actual 1964 load duration curve for the interconnected utilities of this region. It is seen that almost as much capacity is required for only 20 percent or less of the time, just to meet peakload and maintain reserves, as is required nearly all of the time for baseload, continuous output. Not so apparent is the fact that, with capacity in place, incremental energy production is relatively inexpensive. It is therefore desirable to raise the curve throughout its length relative to the peak, as well as to raise the peak itself.

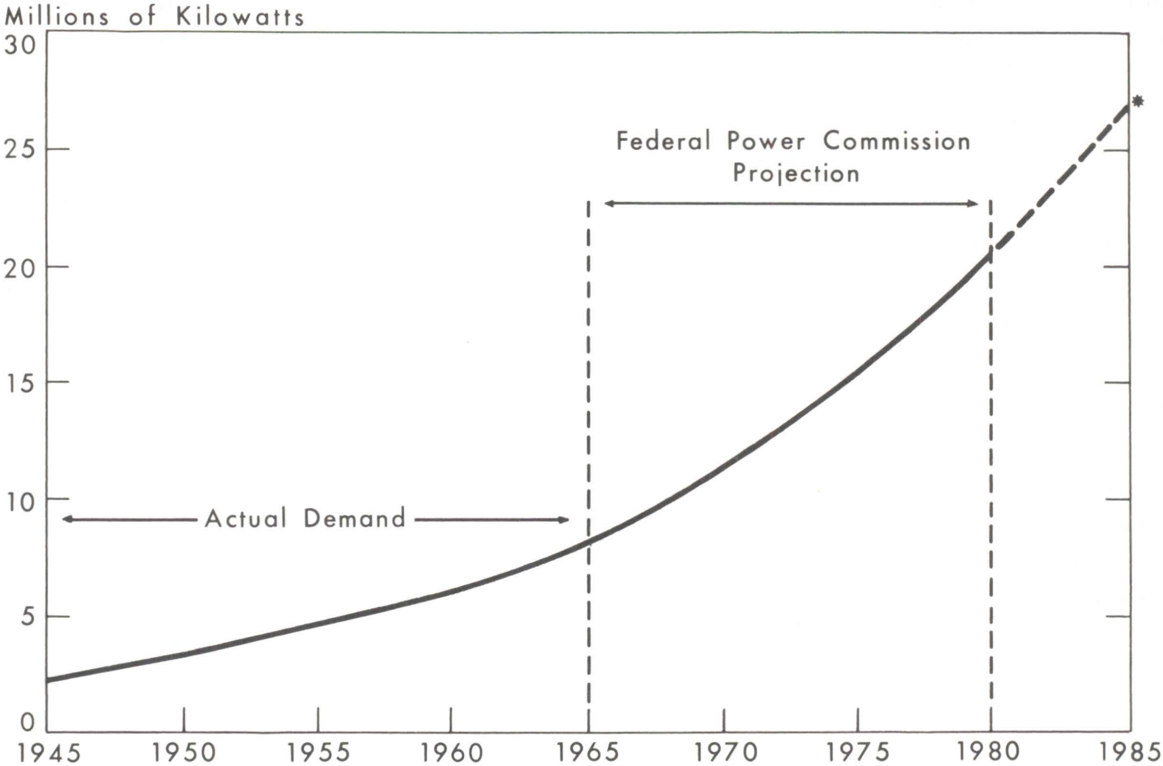
Closely associated with load factor, the composition of total load by customer type follows from the cross-currents of economic and social development within the region. Not surprisingly, with ever greater urbanization of a growing population, residential energy use has risen steadily and now accounts for about 45 percent of power sales. On the other hand, industrial use has risen by 2½ times since 1945 but is now only 25 percent of total sales, declining from 33 percent since the end of World War II. Nationally, it is almost the reverse, industrial sales being 46 percent and residential sales 29 percent. New England, of course, has nothing to compare with the massive industrial concentrations elsewhere.

As household use of electricity becomes an increasingly sensitive barometer of this area's utility growth and a frequently cited indicator of consumer response to rates, the underlying trend is of vital concern to planning and policy. The national average of residential sales per customer in 1964 was 4703 kilowatt-hours; in New England it was 3538 kilowatt-hours. Ten years ago the difference was not so great. This region's householder consumed 25 percent less electricity in 1955, but 33 percent less in 1964, than the national average. Even so, some systems are only a little below the national average and three systems have slightly exceeded it. Two of these, Green Mountain Power and Central Vermont Public Service, offer lower residential rates than other systems and receive power through a contract between the State and the New York Power Authority. Western Massachusetts Electric, on the other hand, has vigorously promoted all-electric residential heating with considerable success. Vermont also offers generally lower industrial rates but the State has not enjoyed the industrial growth rate of the three southern New England States.

Load distribution is far more difficult to "improve" in terms of economic efficiency than either load factor or load composition. In fact, it is rarely altered in the short run except by a favorable combination of factors leading to sizable new economic development. One of the striking characteristics of the New England load is its concentration near the seacoast. An estimated 90 percent of total load is within 45 miles of tidewater, along a 300-mile-long coastal band between Augusta, Maine, and Bridgeport, Connecticut. The remaining 10 percent is spread over 80 percent of the land area, a vast inland market with small concen-

FIGURE 2

PAST AND PROJECTED PEAK LOAD — NEW ENGLAND ELECTRICAL UTILITIES



*Author's extrapolation beyond 1980

trations in the upper Connecticut Valley and in upstate Vermont. The trend is toward a more highly concentrated demand in the future, due to forces independent of the power industry. In increasingly urbanized New England, this basic fact is too often ignored. It is certain to shape future development.

The Federal Power Commission's 1964 *National Power Survey* forecasts New England load growth to 1980 as shown in Figure 2. Peak demand is expected to reach 20,450,000 kilowatts with energy consumption of 104.6 billion kilowatt-hours. This forecast reflects the trend toward higher residential and commercial demand and it indicates that the present annual load factor will prevail over the next 15 years, despite efforts directed toward its improvement. In anticipation of this market, and with a watchful eye on shifting market patterns, the principal utility suppliers are preparing for a growth that will approach 650,000 kilowatts annually by the early 1970's.

Industry-Market Forces and the Cost of Power

The "high cost of power in New England" has been a popular topic of discussion for some time and remains an issue of valid public concern. Enough comparisons have been made between power rates here and in the rest of the Nation, and enough prescriptions offered for curing the high-cost malady, to keep the consumer both confused and ever hopeful. Unfortunately, oft-quoted percentages too seldom relate to comparable amounts and kinds of power, types of customers, and locational and use factors. Nevertheless, a broad differential does exist, and before examining what is planned or proposed to remedy the situation, some light may be shed by summarizing briefly what has brought it about.

Many elements of cost are involved. First and perhaps most obvious, without local coal mines and oil fields, New England pays the freight on fuel brought from distant sources, and lacking abundant waterpower resources, reliance on fossil fuels has been heavy. Second, state and local taxation is substantially higher in New England than elsewhere in the Nation. Property taxes are particularly burdensome for the capital intensive electric utility industry. Third, many systems elsewhere are either themselves exempt from Federal, state, and local taxes or purchase untaxed power from public systems. In New England, on the other hand, most power systems are privately owned. These utilities pay corporate income taxes. Their stockholders and bondholders pay a tax on both dividend and interest income. This differential taxation largely explains why the financing costs of private systems are almost twice those of publicly owned utilities. In addition, Massachusetts law limits bonded debt to 50 percent of the capital structure, thus keeping higher cost equity financing artificially high. Fourth, today's industry structure, while undergoing a transformation, is still plagued with inefficiencies inherited from earlier times, causing persistent abnormal expenses for fuel, operations, maintenance, and a multiplicity of managements. Administration and General Expenses alone were 2.2 mills per kilowatt-hour of sales in 1964, 87 percent above the national industry average. On a cost-per-customer basis — the more relevant comparison since it costs about as much to administer a 1,000-kilowatt-hour as a 10,000-kilowatt-hour load — New England systems were 26 percent above the national average. Fifth, construction costs have always been higher in New England for many reasons: higher land values for plant sites and transmission rights-of-way, higher wage scales, higher transportation costs from supply points, rough terrain for rural lines, underground cabling in highly settled areas, and more costly plant and transmission design to protect against a seasonally severe climate. Sixth, most of these same reasons impose higher operation and maintenance expenses as well.

The direct impact of these costs on power rates has the further indirect effect of discouraging energy consumption, which in itself is a factor tending to increase costs. The load duration curve clearly indicates the large amount of capacity that must be maintained for only short-time use. This unfavorable situation is accentuated by two factors not common to most systems with which New England is frequently compared. First, due to climate — some harsh winter days and lack of widespread need for summer air-conditioning — the region experiences a sharp winter peak and lower summer consumption. Many areas of the country have a summer peak which matches or exceeds their winter peak. Second, high energy consumption occurs in areas where heavy industry predominates. In New England, the industry mix is typified by small, diversified labor-intensive manufactures with low load factors, in contrast to the high load-factor industries producing steel, aluminum, and chemicals. For better or worse, depending on one's viewpoints, New England was not endowed with a combination of abundant raw materials and proximity to national markets such as is attractive to heavy power-consuming manufacturers.

This combination of supply and demand forces has kept power rates where they are. While rate reductions exceeding $22 million have been put into effect in the past 3 years, reflecting cost reductions already achieved, public pressure for more dramatic results remains strong. Two major efforts by the industry — one little publicized but highly significant, the other in large part already announced — show promise of producing such results. The first is intersystem coordination on a scale not heretofore accepted. The second is the industry plan for development.

Intersystem Coordination

Coordination among a group of neighboring utilities in system planning, development, and operations can achieve substantial economies. The essential ingredients are a willingness to negotiate agreements and a network of strong interconnecting transmission circuits. When these exist, the advantages to be gained are impressive:

- larger, more efficient baseload generators can be installed for combined load growth than can be justified for a single company

- larger, lower cost peaking installations can be justified, such as pumped storage, to carry the combined peaks of several systems than are warranted for individual system peaks

- the most economical location for new plants can be selected in terms of site, fuel sources, and combined markets, without regard to company boundaries

- the most economically routed, high-capacity, joint-use transmission lines can be installed, without regard to company boundaries

- load diversity among systems due to time zone, load type, and seasonal differences occasions a lower simultaneous peakload on interconnected systems than the sum of peaks of separate systems, thereby permitting systems which share capacity to maintain lower combined peaking capability

- unscheduled outage diversity (simultaneous breakdown) among systems occasions a lower simultaneous outage on interconnected systems than the sum of outages on separate systems, thereby permitting systems which share reserves to maintain lower combined reserve margins

- streamflow diversity throughout an area may enable two or more systems with hydro capacity to gain firm dependable hydropower if water release schedules are coordinated

- two or more systems with both hydro and thermal capacity may save fuel during high stream runoff periods and enhance firm dependable hydropower in low-flow periods by exchanging hydro and thermal energy

- scheduled maintenance capacity and spinning reserve capacity can be minimized and can be provided by more efficient standby machines, when two or more systems coordinate their maintenance programs and share their best operating reserves

- coordinated dispatching of total load of combined systems assures that load increments are met with the least costly generation and related transmission increments available

- engineering and administrative cost savings can be realized by the pooling of talent in planning and operations.

These concepts are not new to the industry; neither are they costless nor everywhere applicable. Load diversity and streamflow diversity, for example, are not as significant *within* a small region such as New England as *between* regions. Similarly, the degree and price of coordination vary together. Therefore, the industry has approached coordination, not for its own sake, but with a careful weighing of required investments and potential gains.

Accepting as fact the somewhat fragmentary industry structure, and the natural reluctance of companies to sacrifice sovereignty, what is the record of intersystem coordination in this region? Recognition that the isolated system could not hope to meet exacting modern standards of economy and service reliability led some utilities into early but limited forms of cooperation. Sharing of production, much easier to arrange and account for than sharing of transmission, has taken three forms: joint ownership, unit contracts, and firm contracts. Going back at least 44 years, three small operating companies formed Montaup Electric Company (all four now subsidiaries of Eastern Utilities Associates) to build Somerset power station in Rhode Island. Capacity of this joint-ownership venture, now grown from 38,000 to 329,000 kw, is still being shared. Its modern counterparts are Yankee Atomic Electric Company, jointly owned by 10 companies and now operating the 185,000-kw "first generation" prototype nuclear unit at Rowe, Massachusetts, Connecticut Yankee Atomic Power Company with 11 companies participating in a 500,000-kw "second-generation" nuclear unit now under construction, and Maine Yankee Atomic Power Company with 11 participants in a planned 700,000-kw station.

The more frequently employed "unit contract" is sometimes a long-term agreement among two or more systems which relates to specific generating units financed by a single system. Price to the company contracting for a portion of the output is based on performance of the unit, so the transaction is normally made at cost with risk of outages also shared. NEGEA's 550,000-kw Cape Cod Canal unit #1, for example, will be owned and operated by its subsidiary, Plymouth County Electric, but output will be shared equally with Boston Edison, New England Power (A NEES generating subsidiary), and Montaup Electric for 33 years. Actual fixed and variable plant costs (except fuel) will be divided equally among the four contracting parties, and fuel expense will be prorated on an energy-delivered basis. Similarly, Public Service of New Hampshire will sell 100,000 kw of its scheduled 350,000-kw Merrimack unit #2 to VELCO, a transmission subsidiary of three Vermont companies, for distribution in Vermont for 30 years under the same pricing policy. Neither of the owning companies nor most participants could have justified such large units for their own near-term load growth alone.

Short-term capacity-sharing contracts have also become common. They also normally take the form of unit contracts relating to specific facilities. Less frequently used two-party firm contracts not tied to unit performance provide for demand and energy charges and a minimum purchase obligation, such as in bulk supply contracts between major wholesalers and smaller distribution systems. As examples of unit contracts, in 1961 Central Maine Power arranged to buy 15,000 kw of New England Power's Brayton Point output in 1964, enabling it to defer construction of its 125,000-kw Wyman unit #3 for 1 year. In turn, Central Maine is selling a share of Wyman for 3 years to Public Service of New Hampshire and VELCO, permitting deferment of Merrimack #2 and other Vermont additions. Public Service of New Hampshire will also buy 50,000 kw for 1 year from Boston Edison, made available with completion of Boston Edison's 400,000-kw New-Boston unit in 1965. Meanwhile, Boston Edison bought 100,000 kw from New England Power during 1964, but is now selling 100,000 kw of New-Boston #1 to New England Power for 5 years. New England Power, in turn, sells to Vermont and buys from Consolidated Edison of New York and Niagara Mohawk. The Connecticut companies also have agreements with neighboring New York utilities.

These are recent examples of a long series of arrangements proving increasingly useful over the years with the advent of large generator units and higher voltage transmission. Through some 50 system interconnections of 69,000 volts or higher, and a number of lesser capacity ties, the major utilities have also developed informal bi-lateral and multi-lateral working agreements or formal contracts covering reserve sharing, emergency interchange, load frequency control, mutual support during maintenance outages, and other aspects of partial coordination over widespread service areas.

The Connecticut companies with Western Massachusetts Electric have pioneered in a more detailed concept of operational integration. As members of the Connecticut Valley Electric Exchange, or CONVEX, and predecessor pooling organizations dating from the 1920's, these companies are committed to joint-use generation and transmission capacity planning, coordinated design and development, and virtually complete one-system operational integration. The distinguishing feature of their pooling is multi-system economic load dispatching, whereby a central dispatch office is empowered to call upon least-costly increments of production from participating companies, irrespective of ownership, to meet load increments and similarly, as load declines, to call for selective unit back-off or shut-down, spinning reserve (responsive capability on the line but not generating) and cold reserve.

This procedure has been partially automated for nearly 10 years by electronic computer control. Knowing the incremental fuel efficiencies at all output levels for each of 22 thermal generators, as well as transmission losses incurred between each generator and load centers, a computer in Southington, Connecticut acts to minimize the delivered cost of power. By continuous

PRIVATELY OWNED UTILITIES EXPANSION PLANS

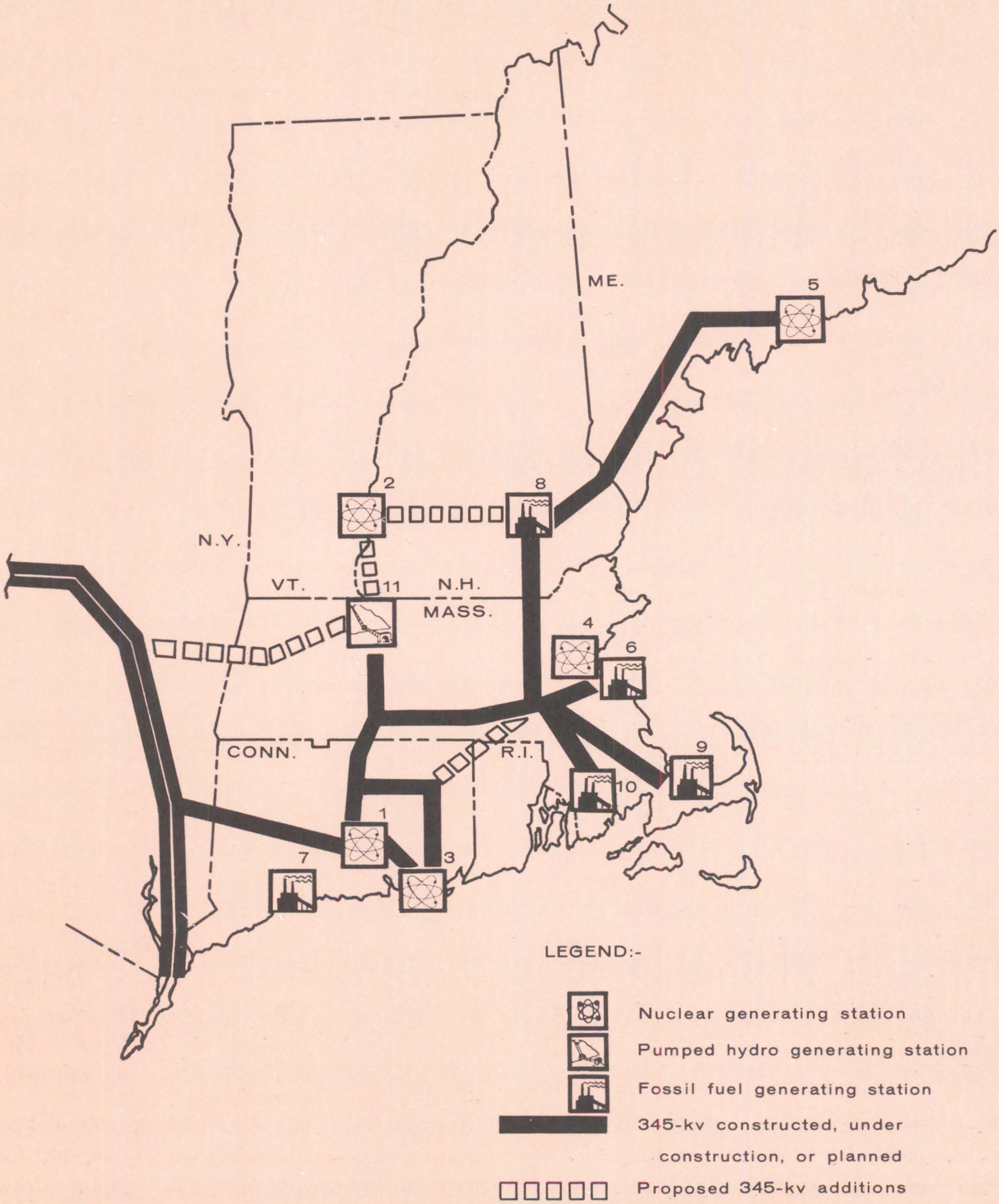


TABLE 2
Industry Plans
Generation and Transmission Additions, 1966-72

Map No.	Plant Additions	Year Completed	Capability (maximum kw)	Cost ($ millions)
	Nuclear			
1	Connecticut Yankee	1967	500,000	
2	Vermont Atomic	1969	450,000	
3	Millstone Point	1969	600,000	
4	Boston Edison	1971	650,000	
5	Maine Atomic	1972	700,000	
			2,900,000	390
	Fossil-fueled			
6	New-Boston #2	1967	400,000	
7	Bridgeport Harbor #3	1968	400,000	
8	Merrimack #2	1968	350,000	
9	Cape Cod Canal #1	1968	560,000	
10	Brayton Point #3	1969	640,000	
			2,350,000	250
	Pumped Storage			
11	Northfield Mountain	1971	1,000,000	70
	Transmission			
	345-kv lines, substations, and operating equipment	1972		90
	Total additions and costs		6,250,000	800

night-and-day calculations of the cost level of all units connected to load, and continuous scanning of other available units (or other output levels of connected units) for the next-best source of supply, adjustments are automatically signalled directly to the operating and on-call machines. On occasion, of course, service reliability takes precedence over strictly economic decisions. Present limited computer capability precludes economic dispatch of 11 additional thermal and several hydro plants on the CONVEX systems, and until a larger computer now on order is installed, manual dispatch of these units will continue. These and other system functions are performed by means of leased telephone, carrier current, telecommunications, and micro-wave. The close coordination so far achieved in CONVEX results in part from concentration of supply and load.

Elsewhere in New England, greater dispersion of supply, load, and ownership account for autonomous operations of most systems. New

England Electric, operating widespread hydro and thermal properties in a four-state area, at present dispatches its own system manually but plans for early full automation. Central Maine Power's new computer center has the capability for multi-system economic dispatch. For the past 5 years Boston Edison has dispatched 16 units within its own system on the same advanced, fully-automated basis as employed in CONVEX, and has recently taken on the manual dispatch of the NEGEA system as well. The remaining utilities operate as essentially separate entities. Nevertheless, a considerable degree of intersystem coordination is achieved by means of the contracts described and less formal procedures. Economy energy interchange (sometimes called "economy flow") is operative on a daily and hourly basis through instant communication among load dispatchers. Typically, a system experiencing increasing load, but faced with relatively high incremental energy costs in its own plants (say 5 mills), will call adjacent systems for quotations until a block of more economical (say 4 mills) energy is found for a stated time period, whereupon an exchange transaction is effected, the flow of power is metered, and the 1-mill saving is split between buyer and seller.

While substantial benefits accrue from present procedures, potential savings appear even greater, both from more inclusive system groupings and from more refined, fully-automated operating decisions. As now constituted, economic loading still relies to a considerable degree on manual calculations and experienced judgment, albeit with a high degree of accuracy. Fuel cost and plant factor comparisons among neighboring units reveal the extent to which opportunities for economy flow are foregone. With greater instrumentation, the performance of more alternative choices can be more quickly and accurately determined in response to fast changing market conditions. In terms of the 1980 energy forecast, a *1 percent* saving in energy cost will be worth $3 million annually. Studies now in progress may lead to adoption of a Master systems operations center for all of New England with perhaps four multi-system Satellite centers patterned after CONVEX on a sub-area basis. Such an integrated complex would achieve near-optimal area-wide operational coordination.

Mere size and monolithic structure are not always guarantees of efficiency. Nonetheless, it might be argued persuasively from the sole standpoint of economic efficiency, that an area the size of New England could best be served by a single utility system. Regulated in the public interest, the benefits of complete corporate, engineering, operational, maintenance, and administrative integration would indeed be considerable. Short of this, since most systems are simply not for sale, the industry has achieved a degree of coordination which, if advanced to the levels now contemplated, will approach the one-system concept. It is evident from emerging industry plans that further progress in this direction is inevitable.

Industry Plans and the Impact on Costs and Rates

In the Electric Coordinating Council's Planning Committee, the vehicle has been created for a unified approach to future development. Representing 13 utility systems, this engineering-economic group is the source of recommendations to corporate management for investment decisions. As an advisory group, it suggests; management prerogative to reject suggestions is clear. One of its several specialized sub-committees is now engaged in the task of structuring an area-wide power system to meet a moving load target to 1990 at lowest cost and with greatest service reliability. Its work, labelled a "Study of Alternative Capacity Expansion for a One-System New-England," deals with the design variables already mentioned: load characteristics; plant location and size, type and source of fuel, thermal efficiency, transmission circuits; baseload, peaking and reserve capacity; operating tools and techniques, system costs and output. Many alternative designs, or patterns of generation expansion, are being tested and compared by computer simulation, in search of the optimal combination of variables over time for meeting the objective.

Meanwhile, specific plans have been formulated for nearer-term objectives and some have already been translated into action programs. The accompanying map shows generating additions and associated 345,000 volt backbone transmission now under construction or reasonably certain of development in the next 7 years. This program reflects a blend of Planning Committee technical recommendations for the area and managerial judgment of individual company responsibilities, capabilities, and strategy. Table 2 lists generating additions keyed by number to map locations which, if brought into being, will constitute nearly 45 percent of the total New England power capability, including reserves, available to meet the predicted 13-million-kilowatt 1972 peak. Baseloaded to operate at very high plant factors, they will produce an estimated 60 percent of 1972 kilowatt-hours. Taking into account expected plant retirements, over 61 percent of 1972 capability and nearly 75 percent of generation will come from plants less than 15 years old. If retirements were based solely on unit size and age, the 11 additions would permit dismantling of over 100 old units and still meet the 1972 peak load with adequate reserves.

The $800 million estimate, large as it seems, is low by comparison to prices of the recent past. It may even be reduced as projects come under contract, unless inflation destroys the gains that are clearly in sight. Power supply technology and design are steadily improving. Keen competition prevails in the equipment and construction industries, and fossil fuel suppliers are well aware of the inroads being made by nuclear fuel. Recent "turnkey" contracts for design, equipment and construction of complete power stations, and recent completion of much EHV transmission, give evidence that costs are being lowered.

At prevailing prices and with 75-90 percent plant factor operation of the 10 baseload plants, production costs will be sharply lower than present levels for the region. When in full production, these units and the remarkably low-cost 25 percent plant factor pumped storage hydro will produce at about the following levels:

	Billion kwh	Mills per kwh
nuclear	23.3	4.5
conventional thermal	15.5	5.0
pumped storage hydro	2.2	8.1
total	41.0	4.9

The nominal cost of 345-kv backbone transmission — 4/10 of one mill per kilowatt-hour of new generation — is not included, as this network will be shared by all present and future production.

While this massive low-cost increment of interconnected generation is certain to have a pronounced impact, it is not an easy matter to trace the precise effect on power costs to the ultimate consumer. Any sweeping predictions in this regard concerning any increment of low-cost power to New England can be grossly misleading. It is often overlooked, or ignored, that all of today's distribution costs and most of today's high-voltage transmission and generation costs will remain in the systems of 1972. It is therefore appropriate to view the forthcoming program as a single production increment delivering power into the existing systems at multiple points, and to compare *present production* costs against *projected 1972 production* costs with the low-cost increment averaged in. The reduction or saving must then be measured against *total delivered* costs to ultimate customers. This approach does not reflect improvements to existing systems by 1972 from plant retirements, more complete coordination, and other favorable cost factors, such as depreciated book values, nor does it reflect the slightly higher costs of operating present units in 1972 for shorter duration as newer units take the baseload, but it does provide a close approximation.

The average total delivered cost — production, transmission, and distribution — to ultimate customers in 1964 on the systems serving 97 percent of load was about 24 mills per kilowatt-hour. The production component of this total was just over 50 percent, or 12 mills, including prorations of fixed charges and general expense. With 62 percent (41 billion kilowatt-hours) of 1972 production at the new level of 4.9 mills, and the remaining 38 percent at the prevailing level of 12 mills, the weighted average production costs in 1972 should be about 7.6 mills, with no other improvements assumed, or *37 percent less* than in 1964. The reduction of 4.4 mills would lower the present delivered cost of 24 mills by about 19 percent. It is clear that dramatic results can be achieved only by a truly immense increment of strategically located new power supply of the magnitude now contemplated by the industry.

Looking beyond 1972, emerging plans of the utilities are less certain. Present thermal production sites are said to be suitable for expansion by 5 to 6 million kilowatts for baseload output, and excellent sites for development of some two million kilowatts more of very low-cost pumped storage for peaking are said to be available. If the historical trend of increasing efficiency in power supply continues, even lower-cost baseload power is in prospect than is now foreseen. Furthermore, any pumped storage peaking will become cheaper with age, since its major cost component is the pumping energy supplied to it by thermal generation.

Yankee Power in Transition

A quiet revolution in electric power technology is bringing forth new opportunities, new concepts, and new plans which promise dramatic change to historical circumstances and traditional ways. Publicized regional differences are narrowing as persistent regional disadvantages are overcome. New England's utilities are active participants in this revolution, and they propose to put its benefits to work in power markets of the 1970's and 1980's. Certain implications of the developing situation seem clear:

- By 1972, barring further inflation, the average price of electricity may be reduced as much as 25 percent by a massive increase in productive capacity, a strong high-voltage transmission network, and closer intersystem and interregional coordination of operations.

- The one-system concept may be made operational in most of New England in the years ahead, bringing increasing economy and reliability, and presenting a formidable private industry yardstick of power costs and service.

- Small systems, both public and private, may continue to suffer inherent cost disadvantages unless they are able to participate more broadly in the one-system concept.

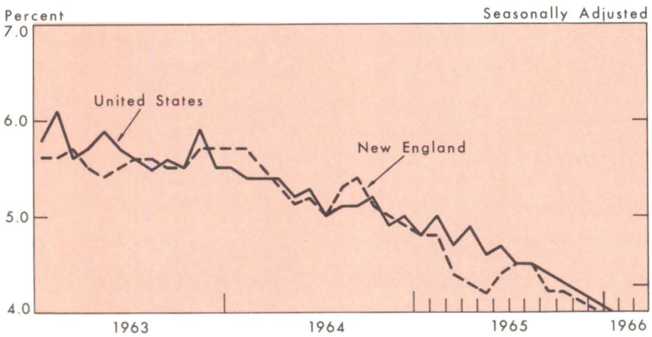
- The vast "inland" market may continue to suffer inherent cost disadvantages unless it can participate in the benefits of the one-system concept or chooses to seek other solutions.

- As New England is encouraged by lower rates to use its power system capabilities less sparingly, further economies are in prospect and load may grow even faster than predicted.

New proposals — for a Canadian hydropower import, an Appalachian thermal power import, a Maine Power Authority, and Dickey-Lincoln School project — should be examined in the light of these implications. In this period of rapid change, one thing seems certain: by 1980, over 90 percent of electric energy consumed in New England will be generated in power plants not yet in service today. Herein lies the opportunity to meet an old problem with new tools. It is an opportunity for resourcefulness, innovation, and cooperation. It should be viewed by all as an opportunity for real public service.

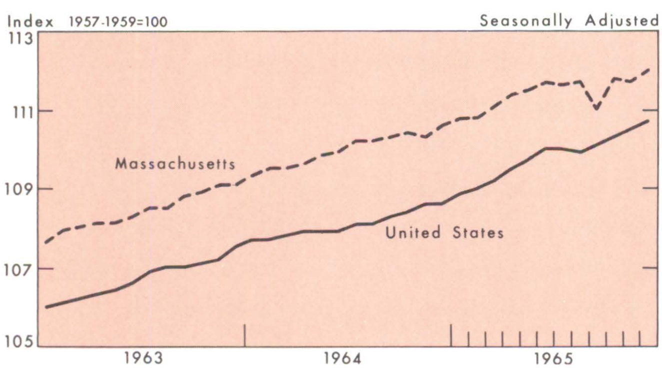
Some Economic Indicators

UNEMPLOYMENT RATES



Unemployment rates have shown a dramatic decline in both the region and the Nation and have reached their lowest levels since 1957.

CONSUMER PRICES



Consumer prices on the other hand have risen to new highs. The temporary September drop in Massachusetts prices was concentrated in the food and housing components.

Here's New England –

February 1966

MANUFACTURING INDEXES (seasonally adjusted) 1957–59 = 100	NEW ENGLAND pDec. '65	Nov. '65	Dec. '64	UNITED STATES Dec. '65	Nov. '65	Dec. '64
All Manufacturing	139	137	126	150	148	139
Nonelectrical Machinery	152	150	136	169	168	151
Electrical Machinery	157	152	139	173	168	149
Transportation Equipment	183	176	145	161	157	140
Textiles, Apparel, Leather	102	108	104	140	139	132
Textiles	103	110	105	140	139	130
Apparel	102	109	114	n.a.	147	141
Leather and Shoes	96	100	95	n.a.	110	106
Paper	135	132	125	149	147	140

	New England	Percent Change From:		United States	Percent Change From:	
BANKING AND CREDIT	Dec. '65	Nov. '65	Dec. '64	Dec. '65	Nov. '65	Dec. '64
Commercial and Industrial Loans ($ millions) (Weekly Reporting Member Banks)	2,234	0	+20	49,850	+ 2	+20
Deposits ($ millions) (Weekly Reporting Member Banks)	6,417	+ 1	+11	161,991	+ 3	+ 9
Check Payments ($ billions) (Selected Metropolitan Areas)*	217.3	+ 5	+21	3,249.6	+ 2	+16
Consumer Installment Credit Outstanding (index, seas. adj. 1957–59 = 100)	162.7	+ 1	+10	197.4	+ 1	+13
DEPARTMENT STORE SALES (index, seas. adj. 1957–59 = 100)	132	0	+ 5	n.a.	n.a.	n.a.
EMPLOYMENT, PRICES, MAN-HOURS & EARNINGS						
Nonagricultural Employment (thousands)	4,070	+ 1	+ 3	62,563	+ 1	+ 4
Insured Unemployment (thousands) (excl. R.R. and temporary programs)	89	+20	−32	1,255	+20	−23
Consumer Prices (index, 1957–59 = 100)	112.0 (Mass.)	0	+ 1	111.0	0	+ 2
Production-Worker Man-Hours (index, 1957–59 = 100)	104.1	+ 2	+ 7	114.3	0	+ 6
Weekly Earnings in Manufacturing ($)	102.25 (Mass.)	+ 2	+ 5	110.92	+ 1	+ 4
OTHER INDICATORS						
*Total Construction Contract Awards** ($ thous.)*	203,389	−11	+ 4	3,933,145	− 4	+ 4
Residential	89,205	− 9	+11	1,679,899	− 6	+12
Nonresidential	83,436	− 9	+ 1	1,447,454	− 1	+ 9
Public Works and Utilities	30,748	−22	− 8	805,792	− 5	−17
Electrical Energy Production (4 weeks ending Dec. 25th, 1965) (index, seas. adj. 1957–59 = 100)	158	+ 1	+ 6	165	0	+ 8
Business Failures (number)	62	+ 7	+15	1,090	+ 6	+13
New Business Incorporations (number)	1,208	+50	+ 8	18,185	+20	+ 4

*Seasonally adjusted annual rate.
**3-mos. moving averages — Oct., Nov., Dec..

p = preliminary

n.a. = not available

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